K 12.4

OPG

EB-2016-0152

OEB Staff Compendium

Panel 3B

A summary of actual and planned operating costs in the nuclear revenue requirement over the 2013-2021 period is presented in Ex. F2-1-1 Table 1.

OPG continues to benchmark annual performance of Darlington and Pickering (Safety, Reliability, Value for Money and Human Performance) based on ScottMadden methodologies established in 2009, consistent with its obligations under the Memorandum of Agreement with the Shareholder (Ex. A1-4-1 Attachment 2). In 2015, ScottMadden validated the ongoing appropriateness of OPG's application of the benchmarking methodology (see Attachment 3 to this exhibit). Of the three key indicators of TGC/MWh, WANO Nuclear Performance Index ("NPI") and Unit Capability Factor ("UCF"), Darlington has achieved a combination of first quartile (TGC/MWh) and second quartile (WANO NPI; UCF) performance. Pickering continues fourth quartile performance for all three metrics. As discussed below, Pickering's performance on these three key indicators is reflective of its small unit size, first generation CANDU technology, and low capability factor for extensive planned outage programs tied to extending the life of Pickering to the benefit of ratepayers.

OPG recognizes that there are limitations in relying on benchmarking alone to measure and explain performance and highlight areas for improvement. These limitations were specifically addressed in ScottMadden's transmittal letter, attached to the Phase 1 Benchmarking Report (EB-2010-0008, Ex. F5-1-1), which noted the impact of factors influencing OPG's performance gap against best quartile, stating that:

> In our opinion, the comparisons provided in this report present a fair and balanced view of OPG operating and financial performance compared to other operators in the nuclear generation industry. However, it would be inappropriate to generalize regarding OPG's absolute performance based solely upon comparisons to industry averages. Differences in design technology, the number of reactors on site, the geographic size of the site, reactor age, operational condition and other factors all influence OPG's operational and financial performance. Benchmark data can be useful for highlighting performance gaps relative to other nuclear generation operators but prescriptive conclusions regarding OPG's ability to narrow such performance gaps will require further analysis.

Comparison of OPG's CANDU units to industry benchmarks is further complicated by differences that exist between Darlington and Pickering. While OPG's ten nuclear units are

MEMORANDUM OF AGREEMENT

BETWEEN
Her Majesty the Queen in right of Ontario, as represented by the Minister of Energy (the "Shareholder" or “Minister”)
And
Ontario Power Generation, Inc. ("OPG")

5.8 The OPG Board Chair shall report to the Minister annually on the effectiveness of this MOA. Such report shall be provided to the Minister in writing within 90 days after the end of each fiscal period.

5.9 OPG shall provide to the Minister quarterly status updates on its response to the recommendations set out in the Auditor General's 2013 Report.

6 PERFORMANCE EXPECTATIONS

6.1 Operational Expectations

6.1.1 OPG shall operate its generating assets safely, efficiently and cost-effectively, and in accordance with all applicable safety and environmental regulations and standards.

6.1.2 OPG shall pursue cost-effective and efficient operational improvements that maintain the reliability of operations, the safety and security of OPG assets, employees and the public.

6.1.3 OPG shall undertake periodic benchmarking appropriate for its operations and type of assets, including as part of its submissions to the OEB.

6.1.4 OPG shall operate its Ontario based portfolio of generation assets in a manner that contributes to Ontario's and Canada's environmental objectives.

6.1.5 OPG shall ensure that a system is in place for the creation, collection, maintenance, and disposal of records in accordance with corporate policy, guidelines and best practices.

6.1.6 OPG shall make information targeted to the general public available in French where it meets a need to do so.

a. Recognizing that OPG's direct interaction with the public is often limited to regional or host community communications or broader public safety, OPG shall make information available in French only if reasonable in the circumstances.

b. For greater clarity, OPG shall provide the following services and products in French: advertising, news releases and educational materials where it meets a need to do so. As well, public safety communications, annual financial reports and educational materials will be provided in French and French speaking spokespeople will be made available as required for public and media interaction. French language products will be listed under a specific heading on the OPG web site.

c. This list shall be reviewed by OPG annually.

6.1.7 OPG shall support the province of Ontario in implementing its policy of putting conservation first by pursuing energy efficiency improvements in its operations where

Memorandum of Agreement

BETWEEN

Her Majesty the Crown In Right of Ontario (the "Shareholder")
And
Ontario Power Generation ("OPG")

Purpose

This document serves as the basis of agreement between Ontario Power Generation Inc. ("**OPG**") and its sole Shareholder, Her Majesty the Queen in Right of the Province of Ontario as represented by the Minister of Energy (the "**Shareholder**") on mandate, governance, performance, and communications. This agreement is intended to promote a positive and co-operative working relationship between OPG and the Shareholder.

OPG will operate as a commercial enterprise with an independent Board of Directors, which will at all times exercise its fiduciary responsibility and a duty of care to act in the best interests of OPG.

A. Mandate

1. OPG's core mandate is electricity generation. It will operate its existing nuclear, hydroelectric, and fossil generating assets as efficiently and cost-effectively as possible, within the legislative and regulatory framework of the Province of Ontario and the Government of Canada, in particular, the Canadian Nuclear Safety Commission. OPG will operate these assets in a manner that mitigates the Province's financial and operational risk.

2. OPG's key nuclear objective will be the reduction of the risk exposure to the Province arising from its investment in nuclear generating stations in general and, in particular, the refurbishment of older units. OPG will continue to operate with a high degree of vigilance with respect to nuclear safety.

3. OPG will seek continuous improvement in its nuclear generation business and internal services. OPG will benchmark its performance in these areas against CANDU nuclear plants worldwide as well as against the top quartile of private and publicly- owned nuclear electricity generators in North America. OPG's top operational priority will be to improve the operation of its existing nuclear fleet.

4. With respect to investment in new generation capacity, OPG's priority will be hydro- electric generation capacity. OPG will seek to expand, develop and/or improve its hydro- electric generation capacity. This will include expansion and redevelopment on its existing sites as well as the pursuit of new projects where feasible. These investments will be taken by OPG through partnerships or on its own, as appropriate.

5. OPG will not pursue investment in non-hydro-electric renewable generation projects unless specifically directed to do so by the Shareholder.

6. OPG will continue to operate its fossil fleet, including coal plants, according to normal commercial principles taking into account the Government's coal replacement policy and recognizing the role that fossil plants play in the Ontario electricity market, until government regulation and/or unanimous shareholder declarations require the closure of coal stations.

7. OPG will operate in Ontario in accordance with the highest corporate standards, including but not limited to the areas of corporate governance, social responsibility and corporate citizenship.

8. OPG will operate in Ontario in accordance with the highest corporate standards for environmental stewardship taking into account the Government's coal replacement policy.

B <u>Governance Framework</u>

The governance relationship between OPG and the Shareholder is anchored on the following:

1. OPG will maintain a high level of accountability and transparency:

   - OPG is an *Ontario Business Corporations Act* ("OBCA") company and is subject to all of the governance requirements associated with the OBCA.
   - OPG is also subject to the *Freedom of Information and Protection of Privacy Act*, the *Public Sector Salary Disclosure Act* and the *Auditor General Act*.
   - OPG's regulated assets will be subject to public review and assessment by the Ontario Energy Board.
   - OPG will annually appear before a committee of the Legislature which will review OPG's financial and operational performance.

2. The Shareholder may at times direct OPG to undertake special initiatives. Such directives will be communicated as written declarations by way of a Unanimous Shareholder Agreement or Declaration in accordance with Section 108 of the OBCA, and be made public within a reasonable timeframe.

C. <u>Generation Performance and Investment Plans</u>

1. OPG will annually establish 3 –5 year performance targets based on operating and financial results as well as major project execution. Key measures are to be agreed upon with the Shareholder and the Minister of Finance. These performance targets will be benchmarked against the

performance of the top quartile of electricity generating companies in North America.

2. Benchmarking will need to take account of key specific operational and technology factors including the operation of CANDU reactors worldwide, the role that OPG's coal plants play in the Ontario electricity market with respect to load following, and the Government of Ontario's coal replacement policy.

3. OPG will annually prepare a 3 – 5 year investment plan for new projects.

4. Once approved by OPG's Board of Directors, OPG's annual performance targets and investment plan will be submitted to the Shareholder and the Minister of Finance for concurrence.

D. Financial Framework

1. As an OBCA corporation with a commercial mandate, OPG will operate on a financially sustainable basis and maintain the value of its assets for its shareholder, the Province of Ontario.

2. As a transition to a sustainable financial model, any significant new generation project approved by the OPG Board of Directors and agreed to by the Shareholder may receive financial support from the Province of Ontario, if and as appropriate.

E. Communication and Reporting

1. OPG and the Shareholder will ensure timely reports and information on major developments and issues that may materially impact the business of OPG or the interests of the Shareholder. Such reporting from OPG should be on an immediate or, at minimum, an expedited basis where an urgent material human safety or system reliability matter arises.

2. OPG will ensure the Minister of Finance receives timely reports and information on multi-year and annual plans and major developments that may have a material impact on the financial performance of OPG or the Shareholder.

3. The OPG Board of Directors and the Minister of Energy will meet on a quarterly basis to enhance mutual understanding of interrelated strategic matters.

4. OPG's Chair, President and Chief Executive Officer and the Minister of Energy will meet on a regular basis, approximately nine times per year.

5. OPG's Chair, President and Chief Executive Officer and the Minister of Finance will meet on an as needed basis.

6. OPG's senior management and senior officials of the Ministry of Energy and the Ministry of Finance will meet on a regular and as needed basis to discuss ongoing issues and clarify expectations or to address emergent issues.

7. OPG will provide officials in the Ministry of Energy and the Ministry of Finance with multi-year and annual business planning information, quarterly and monthly financial reports and briefings on OPG's operational and financial performance against plan.

8. In all other respects, OPG will communicate with government ministries and agencies in a manner typical for an Ontario corporation of its size and scope.

F. Review of this Agreement

This agreement will be reviewed and updated as required.

Dated: the 17th day of August, 2005

On Behalf of OPG:	On Behalf of the Shareholder:
Original signed by:	Original signed by:
Jake Epp Chairman Board of Directors	Her Majesty the Queen in Right of the Province of Ontario as represented by the Minister of Energy, Dwight Duncan

MR. MILLAR: Okay. And that's -- but inherent in benchmarking is it's not so much the absolutes that matter, it's your relative performance to your peers. And that is what your shareholder asked you to do?

MS. SWAMI: They did ask us to benchmark. And as you know, we have talked a lot about the setting of the targets. We look to set our targets to make those improvements.

But as I have said, the other utilities are also doing a similar process and they are also driving their performance.

So yes, while we are benchmarking, the benchmark is constantly changing as well.

MR. MILLAR: And the shareholder in the memorandum of agreement didn't draw any distinction between Pickering and Darlington; is that fair?

MS. SWAMI: That's correct.

MR. MILLAR: It just said OPG's nuclear operations?

MS. SWAMI: As far as benchmarking, yes.

MR. MILLAR: So I asked you a question and I am not sure I got an answer. My question is: Are you satisfied with your level of performance so far?

MS. SWAMI: We are never satisfied with our level of performance. We are always striving to make improvements.

And would I like to see us move up the relative ranking? Of course. OPG is always interested in trying to make our performance better, and that's why we have targeted improvement programs, which we have talked about in the evidence and I won't go through them here.

But clearly we would like to see better performance from our plants.

MR. MILLAR: Is it fair to say -- and I guess I am not quite sure where 10 out of 14 is, but for the three key metrics, at least up to 2011 and for at least two out of three up to 2012, you would be in the bottom quartile overall?

MS. CARMICHAEL: No -- well, if you look at our benchmarking report for Darlington, we are in top quartile TGC --

MR. MILLAR: I am talking overall.

MS. CARMICHAEL: From a major operator perspective comparison, I would say that on a quartile basis it does appear to be that.

I would also like to just give you a little bit of information. I know that relative to the rankings, we appear to not be improving, but if you look at the absolute numbers of our -- for our company, for OPG nuclear we have shown improvement in those three areas. So in -- for our unit capability factor from 2008, we were at 77.4 percent and in 2012 we were at 82.9 percent.

This just is substantiating Ms. Swami's statement that we are improving but the industry also is improving, so it's a relative issue.

In terms of total generating cost, in 2008 on an operator level, we were at $60.34, and we have improved in 2012 to $46.92.

The Board does not believe it is sufficient for OPG to simply discount the benchmarking studies on the basis of data quality. The studies are all based on standard measures used by the nuclear industry throughout the United States and Canada. While caution should be exercised when reviewing such data, the Board is satisfied that the studies provide meaningful insights into OPG's operations. Moreover, even if there are frailties in the data, the differentials remain striking, particularly with respect to Pickering A. The reason why the MOA emphasized benchmarking was because such studies can and do shine a light on inefficiencies and lack of productivity improvement.

While OPG criticizes the data, the Board notes that few steps have been taken to improve the quality of studies. The Board also notes that benchmarking studies were not filed as a matter of course but rather were reluctantly produced during the course of cross-examination.

Moreover, the Board was surprised that OPG has not followed up with the suggested Phases 2, 3 and 4 of the benchmarking analysis suggested by Navigant. While the benchmarking is critical to the Board (and it would seem to the shareholder), it appears that OPG has done little since the completion of the Navigant Study. The Navigant Study was delivered two years ago on September 15, 2006. There appear to be no benchmarking studies underway. And OPG has not decided what benchmarking evidence, if any, it will present at the next rates case.

Navigant completed Phase I of its study in 2006. Phase 2 as described at page 9 of the Navigant Report was to set OPG's strategy and performance targets. Specifically, Phase 2 was to address the question "what level of cost and operational performance improvement is justified". Phase 3 was to develop and execute an implementation plan. Specifically, Phase 3 was to address the questions "what specific initiatives and actions are needed to achieve identified performance improvement targets".

The questions Navigant suggested should be addressed in the second and third phases of the study are important questions. They are directly responsive to paragraph A.3 of the MOA.[14]

[14] "OPG will seek continuous improvement in its nuclear generation business and internal services. OPG will benchmark its performance in these areas against CANDU nuclear plants worldwide as well as against the top quartile of private and publicly-owned nuclear electricity generators in North America. OPG's top operational priority will be to improve the operation of its existing nuclear fleet."

The Board directs OPG to produce further benchmarking studies in its next application that specifically address the questions raised in the proposed Phase 2 and Phase 3 of the Navigant Report. Whether these studies are performed by Navigant or another firm is a matter to be determined by the applicant.

The production costs of the Pickering A station are a particular concern. In the past, a major reason for the high PUEC for Pickering A has been the extent of unplanned outages and the resulting low capacity utilization. OPG has forecast significantly higher capacity factors for Pickering A in 2008 and 2009. But, as Chart 2-1 illustrates, even at those higher production levels, the PUEC for Pickering will still remain well above the PUEC for Pickering B, will be significantly higher than the PUEC of the Darlington station, and will stay well above the PUEC achieved by the Bruce station over the period 2005 to 2007. Thus, poor capacity factors are not the whole reason for a high PUEC at Pickering A.

The Board estimated the PUEC for Pickering A assuming it were able to reach the forecast capacity factors of the Pickering B station in 2008 and 2009. Even if Pickering A were able to increase its planned capacity factors by that much (from 79% in 2008 and 81% in 2009 to 86% in both years), the Board estimates that the PUEC of Pickering A would only fall to around $70 per MWh, a level that is still much higher than the next highest cost station in Chart 2-1. In the Board's view, this indicates an issue with the overall level of production costs at Pickering A.

Under these circumstances, the Board believes that a reasonable action is to disallow 10% of the Base OM&A costs of Pickering A. This represents a test period disallowance of $14.9 million in 2008 and $20.1 million in 2009. Even with those amounts removed from the revenue requirement, the amount of the operating costs of Pickering A will still remain well above those of other nuclear plants.

The Board will have an opportunity to reexamine this issue when the benchmarking studies are updated in the next proceeding. At that time the Board will examine any improvement or deterioration in production unit energy costs compared to other utilities, and the reasons for those changes.

Aside from this adjustment, the Board will allow the OM&A forecast by OPG. The Board understands the concern of the intervenors regarding the level of costs, but believes it is important to examine underlying cost drivers. A number of the planned expenditures are improvement as well as develop specific initiatives and actions to meet those performance targets.

The 2009 benchmarking initiative began in March 2009 following the retention of ScottMadden. OPG solicited benchmarking consulting services through a request for proposals and selected ScottMadden from among five respondents.

ScottMadden introduced a gap-based business planning process, as shown in Attachment 2, consisting of the following four steps:

- **Benchmarking:** Using selected industry performance metrics, establishing the current status of OPG relative to its peers.
- **Target Setting:** Implementing a "top-down" approach to set operational/financial performance targets and generation targets that will drive OPG closer to top quartile industry performance over the five year business plan.
- **Closing the Gap:** By reference to Nuclear's four cornerstone values of Safety, Reliability, Human Performance and Value for Money, developing various initiatives to close the performance gaps between OPG and its industry peers over the five-year business plan.
- **Resource Planning:** Preparing a OPG Nuclear business plan (i.e., the development of cost, staff and investment plans for each site and support group) that is based on the "top-down" targets and incorporates initiatives necessary to achieve targeted results.

The project was undertaken in two phases:

- **Phase 1: Benchmark Performance** – The goal of this phase was to benchmark OPG Nuclear's operational and financial performance to external peers to determine its relative standing on key operational and financial performance indicators.
- **Phase 2: Set Strategic Direction** – The goal of this phase was two-fold. First, use the benchmarking results to establish performance improvement targets that will achieve, or significantly drive OPG Nuclear closer to, top quartile industry performance. Second, identify the improvement initiatives best able to close the identified performance gaps to ensure that the desired performance targets are achieved. The Phase 1 and Phase 2

reports prepared by ScottMadden are provided at Ex. F5-T1-S1 and Ex. F5-T1-S2, respectively.

3.2 Benchmarking Initiative - Phase 1

During Phase 1, ScottMadden, assisted by OPG Nuclear, (a) identified the key performance metrics that would be benchmarked, (b) identified the most appropriate peer groups for comparison, and (c) prepared supporting analyses and charts.

Effective comparison of performance requires both the selection of appropriate performance indicators, and appropriate peer groups.

Appropriate benchmarking performance indicators are metrics with standard definitions, reliable data sources, and utilization across a good portion of the industry. With these criteria, the Phase 1 process established 19 benchmarking performance indicators divided into three categories which align with OPG Nuclear's cornerstone values of safety, reliability, and value for money, as set out in Chart 1 below. While ScottMadden was unable to recommend specific performance metric for the cornerstone value of human performance, it advised that good or poor human performance is manifest within many of the safety and reliability indicators selected.

OPG Nuclear has traditionally relied upon four primary performance indicators (Production Unit Energy Cost ("PUEC"), Elective Maintenance Backlogs, Unit Capability Factor and Forced Loss Rate) for external benchmarking. In its Phase 1 Report, ScottMadden recommended that OPG use a new metric, Total Generating Cost ($/MWh), as its primary financial benchmark performance indicator in place of PUEC. Total Generating Cost is calculated inclusive of Non-Fuel Operating Cost, Fuel Cost, and Capital Cost.

ScottMadden's rationale for selecting Total Generating Cost is twofold. First, PUEC is not a standard industry benchmark. Second, PUEC excludes consideration of capitalized costs. ScottMadden's Phase 1 report recommends that when benchmarking between OPG's CANDU units and its North American peers, capitalized costs should be included.

result, the names of comparator companies have been redacted in this non-confidential version of the 2015 Nuclear Benchmarking Report.

Of the 20 metrics listed in Table 1, three are used to provide important information regarding major operator performance. These are the WANO Nuclear Performance Index (NPI), Unit Capability Factor (UCF), and Total Generating Cost (TGC) per MWh.

Further information on benchmarking of major operators is provided in Section 6.0 of this report.

MR. SEQUEIRA: Well, the comparators used at OPG are divided into the four cornerstone areas that OPG uses, both for internal management, but that is very consistent with the balance scorecard approach to strategic planning, which we would have recommended had there not been those cornerstones in place.

MR. MILLAR: The phase 1 report benchmarks OPG against comparators for 19 metrics; is that correct?

MR. SEQUEIRA: It is.

MR. MILLAR: And you identify three of those metrics as being key metrics; is that correct? I am referring to page -- I believe it is 140 of your report. I don't know if it is in my materials, but perhaps if I can jog your memory, you speak of the WANO Nuclear Performance Index, the total generating cost per megawatt-hour and unit capability factor.

MR. SEQUEIRA: We have haven't used the... Wait a minute.

MR. MILLAR: When I say page 140, I am referring to the "140" at the top of the page as opposed to the bottom.

MR. SEQUEIRA: We haven't been using the term, because we also have key improvement areas, as well, but those are the three I would say highest-level aggregators of overall performance for an operator.

MR. MILLAR: Okay, thank you for that. Can you tell me a little bit about each of those? What is the WANO Nuclear Performance Index?

MR. SEQUEIRA: Well, WANO is World Association of result, the names of comparator companies have been redacted in this non-confidential version of the 2015 Nuclear Benchmarking Report.

Of the 20 metrics listed in Table 1, three are used to provide important information regarding major operator performance. These are the WANO Nuclear Performance Index (NPI), Unit Capability Factor (UCF), and Total Generating Cost (TGC) per MWh.

Further information on benchmarking of major operators is provided in Section 6.0 of this report.

Summary of Nuclear Benchmarking Reports

	---Rolling Actual Results---								--Annual--				
	a	b	c	d	e	f	g	h	i	j	k	l	m
Darlington	2008	2009	2010	2011	2012	2013	2014	2015	2016 Target Exh A2	2017 Target Exh A2	2016 Forecast Exh N1	2017 Target Exh N1	**2014** "Scott Madden" Phase 2 Report
WANO NPI (Index)	95.67	95.10	94.10	92.80	96.30	90.80	92.10	83.70	87.30	84.30	85.50	83.10	98.60
2-Year Unit Capability Factor (%)	91.99	90.20	89.40	89.60	92.00	90.44	89.41	83.96	91.10	85.10	90.00	85.10	93.30
3-Year Total Generating Costs ($/New MWh)	30.08	32.77	33.55	33.05	31.67	34.42	37.73	44.38	47.35	47.85	46.47	49.75	36.75
Pickering													
WANO NPI (Index)	60.90	67.17	64.30	66.10	64.70	67.50	64.30	68.50	72.30	71.10	75.60	69.70	77.83
2-Year Unit Capability Factor (%)	67.65	74.47	74.57	72.50	75.62	75.77	74.50	77.32	77.60	71.50	75.30	71.50	82.10
3-Year Total Generating Costs ($/New MWh)	67.05	66.42	65.62	65.86	67.16	67.18	67.93	67.36	71.09	76.48	72.46	78.83	66.84
Pickering A													
WANO NPI (Index)	60.84	61.10	47.70										70.90
2-Year Unit Capability Factor (%)	56.60	68.00	61.30										84.30
3-Year Total Generating Costs ($/New MWh)	92.27	95.41	90.21										70.81
Pickering B													
WANO NPI (Index)	60.93	70.20	72.60										81.30
2-Year Unit Capability Factor (%)	73.17	77.70	80.20										81.00
3-Year Total Generating Costs ($/New MWh)	58.68	54.64	54.79										64.80

Q1
Q2
Q3
Q4

Sources:
Column a - EB-2010-0008 Exh F5-1-1 page 12 (ScottMadden Phase 1)
Column b - EB-2010-0008 Undertaking J3.5 Attachment 1 page 4
Column c - EB-2013-0321 Exh L-6.4-SEC-92
Column d - EB-2013-0321 Exh F2-1-1 Attachment 1 page 3
Column e - EB-2013-0321 Exh L-6.4-SEC-92
Column f - EB-2016-0152 Exh L-6.2-SEC-63
Column g - EB-2016-0152 Exh F2-1-1 Attachment 1
Column h - EB-2016-0152 Exh L-6.2-SEC-63 Attchment 3
Column i and j - EB-2016-0152 Exh A2-2-1 Attachment 1 page 30 (2016-2018 Business Plan) - normalized
Column k and l - EB-2016-0152 Exh N1-1-1 Attachment 1 page 24 (2017-2019 Business Plan) - normalized
Column m - EB-2010-0008 Exh F5-1-2 page 16 (ScottMadden Phase 2)

As filed with Applications

OPG Nuclear	2008	2011	2014	2015
WANO NPI (Index)	17th out of 20	24th out of 27	22nd out of 24	23rd out of 24
2-Year Unit Capability Factor (%)	18th out of 20	25th out of 28	21st out of 24	23rd out of 24
3-Year Total Generating Costs ($/MWh)	16th out of 16	12th out of 14	10th out of 13	12th out of 13

Appendix E – Final Business Planning Targets Established for 2014

The tables below present the final operational and financial planning targets agreed to by the OPG Nuclear Executive Committee (NEC) for inclusion in the 2010-2014 Business Plan. **Bold** type is used to indicate the maximum NPI point threshold established by WANO. These thresholds represent guidance as to what is considered superior industry performance.

Safety Cornerstone Targets

Metric	Site / Business Unit	2009 Projection	2014	NA PWR/PHWR Best Quartile	NA PWR/PHWR Median	CANDU Best Quartile	CANDU Median
Tier 1							
All Injury Rate	Darlington	1.3	1.2	n/a	n/a	[redacted]	[redacted]
	Pickering A	1.3	1.2	n/a	n/a	[redacted]	[redacted]
	Pickering B	1.3	1.2	n/a	n/a	[redacted]	[redacted]
	IM&CS	2.36	1.2				
Collective Radiation Exposure* (man-rem)	Darlington	84.66	***66***	50.70	66.00	62.15	81.84
	Pickering A	129.53	125	50.70	66.00	62.15	81.84
	Pickering B	86.04	82	50.70	66.00	62.15	81.84
Fuel Reliability* (microcuries per gram)	Darlington	***0.00050***	***0.00050***	0.000001	0.000012	0.000001	0.000165
	Pickering A	0.00280	***0.00050***	0.000001	0.000012	0.000001	0.000165
	Pickering B	0.00120	***0.00050***	0.000001	0.000012	0.000001	0.000165
Environmental Index (%)	Darlington	85	80	n/a	n/a	n/a	n/a
	Pickering A	80	80	n/a	n/a	n/a	n/a
	Pickering B	80	80	n/a	n/a	n/a	n/a
Accident Severity Rate	Darlington	2.81	3.30	n/a	n/a	n/a	n/a
	Pickering A	4.18	3.30	n/a	n/a	n/a	n/a
	Pickering B	2.41	3.30	n/a	n/a	n/a	n/a
	NP&T	3.34	3.30	n/a	n/a	n/a	n/a
	E&M	2.30	3.30	n/a	n/a	n/a	n/a
	PINO	2.84	3.30	n/a	n/a	n/a	n/a
	NSC	2.42	3.30	n/a	n/a	n/a	n/a
	IM&CS	2.36	3.30	n/a	n/a	n/a	n/a
	NWM	7.34	3.30	n/a	n/a	n/a	n/a

PHWRs

Although the PHWR safety philosophy considers other special safety systems to be paramount to public safety, the following PHWR safety and safety-related systems were chosen to be monitored in order to maintain a consistent international application of the safety system performance indicators:

- Auxiliary boiler feedwater system
- Emergency AC power
- High pressure emergency coolant injection system

These systems were selected for the safety system performance indicator based on their importance in preventing reactor core damage or extended plant outage. Not every risk important system is monitored. Rather, those that are generally important across the broad nuclear industry are included within the scope of this indicator. They include the principal systems needed for maintaining reactor coolant inventory following a loss of coolant, for decay heat removal following a reactor trip or loss of main feedwater, and for providing emergency AC power following a loss of plant off-site power. (Gas cooled reactors have an additional decay heat removal system instead of the coolant inventory maintenance system)

Except as specifically stated in the definition and reporting guidance, no attempt is made to monitor or give credit in the indicator results for the presence of other systems at a given plant that add diversity to the mitigation or prevention of accidents. For example, no credit is given for additional power sources that add to the reliability of the electrical grid supplying a plant because the purpose of the indicator is to monitor the effectiveness of the plant's response once the grid is lost.

The **Nuclear Performance Index** Method 4 is an INPO sponsored performance measure, and is a weighted composite of ten WANO Performance Indicators related to safety and production performance reliability.

The NPI is used for trending nuclear station and unit performance, and comparing the results to the median or quartile values of a group of units, to give an indication of relative performance. The quarterly NPI has also been used to trend the performance and monitor the effectiveness of various improvement programs in achieving top quartile performance and allows nuclear facilities to benchmark their achievements against other nuclear plants worldwide.

The **Forced Loss Rate (FLR)** is defined as the ratio of all unplanned forced energy losses during a given period of time to the reference energy generation minus energy generation losses corresponding to planned outages and any unplanned outage extensions of planned outages, during the same period, expressed as a percentage.

Unplanned energy losses are either unplanned forced energy losses (unplanned energy generation losses not resulting from an outage extension) or unplanned outage extension of planned outage energy losses.

Unplanned forced energy loss is energy that was not produced because of unplanned shutdowns or unplanned load reductions due to causes under plant management control when the unit is considered to be at the disposal of the grid dispatcher. Causes of forced energy losses are considered to be unplanned if they are not scheduled at least four weeks in advance. Causes considered to be under plant management control are further defined in the clarifying notes.

Unplanned outage extension energy loss is energy that was not produced because of an extension of a planned outage beyond the original planned end date due to originally scheduled work not being completed, or because newly scheduled work was added (planned and scheduled) to the outage less than four weeks before the scheduled end of the planned outage.

Planned energy losses are those corresponding to outages or power reductions which were planned and scheduled at least four weeks in advance (see clarifying notes for exceptions).

Reference energy generation is the energy that could be produced if the unit were operated continuously at full power under reference ambient conditions throughout the given period. Reference ambient conditions are environmental conditions representative of the annual mean (or typical) ambient conditions for the unit.

Unit Capability Factor is defined as the ratio of the available energy generation over a given time period to the reference energy generation over the same time period, expressed as a percentage. Both of these energy generation terms are determined relative to reference ambient conditions.

Available energy generation is the energy that could have been produced under reference ambient conditions considering only limitations within control of plant management, i.e., plant equipment and personnel performance, and work control.

Reference energy generation is the energy that could be produced if the unit were operated continuously at full power under reference ambient conditions.

Reference ambient conditions are environmental conditions representative of the annual mean (or typical) ambient conditions for the unit.

The **Chemistry Performance Indicator** compares the concentration of selected impurities and corrosion products to corresponding limiting values. Each parameter is divided by its limiting value, and the sum of these ratios is normalized to 1.0. For BWRs and most PWRs, these limiting values are the medians for each parameter, based on data collected in 1993, thereby reflecting recent actual performance levels. For other plants, they reflect challenging targets. If an impurity concentration is equal to or better than the limiting value, the limiting value is used as the concentration. This prevents increased concentrations of one parameter from being masked by better performance in another. As a result, if a plant is at or below the limiting value for all parameters, its indicator value would be 1.0, the lowest chemistry indicator value attainable under the indicator definition. The following is used to determine each unit's chemistry indicator value:

- PWRs with recirculating steam generators and VVERs
    - Steam generator blowdown chloride
    - Steam generator blowdown cation conductivity
    - Steam generator blowdown sulphate
    - Steam generator blowdown sodium

(DN) that can be worked on without requiring the unit shutdown. This metric identifies deficiencies or degradation of plant equipment components that need to be remedied, but which do not represent a loss of functionality of the component or system.

Online Corrective Maintenance Backlog is the average number of active on-line maintenance work orders per operating unit classified as Corrective Critical (CC) or Corrective Non-Critical (CN) that can be worked on without requiring the unit shutdown. This metric identifies deficiencies or degradation of components that need to be remedied, and represents a loss of functionality of a major component or system.

On-line maintenance is maintenance that will be performed with the main generator connected to the grid.

Value for Money Definitions

The following definition summaries are taken from the *January 2013 EUCG Nuclear Committee Nuclear Database Instructions*.

Capital Costs ($)

All costs associated with improvements and modifications made during the reporting year. These costs should include design and installation costs in addition to equipment costs. Other miscellaneous capital additions such as facilities, computer equipment, moveable equipment, and vehicles should also be included. These costs should be fully burdened with indirect costs, but exclude AFUDC (interest and depreciation).

Fuel ($)

The total cost associated with a load of fuel in the reactor which is burned up in a given year.

Net Generation (Gigawatt Hours)

The gross electrical output of the unit measured at the output terminals of the turbine-generator minus the normal station service loads during the hours of the reporting period, expressed in Gigawatt hours (GWh). Negative quantities should not be used.

Design Electrical Rating (DER)

The nominal net electrical output of a unit, specified by the utility and used for plant design (DER net expressed in MWe). Design Electrical Rating should be the value that the unit was certified/designed to produce when constructed. The value would change if a power uprate was completed. After a power uprate, the value should be the certified or design value resulting from the uprate.

Operating Costs ($)

The operating cost is to identify all relevant costs to operate and maintain the nuclear operations in that company. It includes the cost of labour, materials, purchased services and other costs, including administration and general.

Total Generating Costs ($)

The sum of total operating costs and capital costs as above.

Total Operating Costs ($)
The sum of operating costs and fuel costs as above.

Note: Capital costs, fuel costs, operating costs and Total Generating Costs are divided by net generation as above to obtain per MWh results. Capital costs are also divided by MW DER to obtain MW results.

Human Performance Definitions

The following definition summary is taken from the Institute of Nuclear Power Operations (INPO) database.

Human Performance Error Rate (# per ISAR and Contractor Hours)
The Human Performance Error Rate metric represents the number of site level human performance events in an 18-month period per 10,000 ISAR hours worked (including on site supplemental personnel). The formula used is:

{(# of S-EFDRs) / (Total ISAR Hours + Total Contractor Hours)} x 10,000 Hours (Calculated as an 18-month rolling average)

INPO guidelines define non utility personnel to include contractor, supplemental personnel assigned to perform work activities on site or at other buildings that directly support station operation. This includes personnel who deliver and receive equipment, deliver fuel oil, remove trash and radioactive waste, and provide building and grounds maintenance within the owner-controlled areas or facilities that support the station.

INPO defines an event to occur as a result of the following:

An initiating action (error) by an individual or group of individuals (event resulting from an active error) or an initiating action (not an error) by an individual or group of individuals during an activity conducted as planned (event resulting from a flawed defense or latent organizational weakness). They may be related to Nuclear Safety, Radiological Safety, Industrial Safety, Facility Operations or considered to be a Regulatory Event reportable to a regulator or governing agency. OPG Nuclear's criteria for defining station event free day resets have been developed based on INPO guidelines. However, the definition may differ slightly due to adaptation resulting from technological differences.

OPG's CANDU plants require 1,431 more Full Time Equivalents ("FTEs") than comparator plants and eliminated these FTEs from the staffing study. OPG estimated that this represents $184M of unavoidable OM&A.

As the shareholder has concurred with the business plans that underpin the application, OPG replied that the shareholder has no concerns with OPG's performance under the Memorandum of Agreement.[38] OPG argued that it is not contractually committed to, or required to target or perform to top quartile standards, and that it is not aware of any case where the Board considered failure to achieve top quartile performance in setting rates.

Board Findings

The benchmarking of OPG's nuclear operations is an important reference for the Board. OPG has continued to produce annual nuclear benchmarking reports based on the format and methodology set out in 2009 by the consulting firm ScottMadden. The benchmarking is responsive to the Memorandum of Agreement with the Shareholder and provides the Board with comparative information for its review in a cost of service application. It is the Board's expectation that OPG will continue to produce annual nuclear benchmarking reports based on the ScottMadden methodology and that OPG will file these reports in future cost of service applications.

The benchmarking results for 2008 to 2013 and the targets for the test period were reviewed in this proceeding. The analysis was complicated by the presentation of rolling averages for the historical period and annual targets for the future period. The analysis was further complicated by the reorganization of Pickering. The Board recognizes that some individual units at Pickering and Darlington have improved performance in one or more of the metrics. In OPG's view, it has improved as a major operator in the three key metrics, but in comparison to the industry, OPG is just stable, because the industry also is changing.

Despite these factors, there is no dispute that OPG's performance in the three key metrics is not top quartile, nor does it demonstrate continuous improvement. In fact, for many of the measures OPG remains in the third or fourth quartile. It is also reasonable to conclude that OPG will not reach the aspirational 2014 targets set by ScottMadden and OPG in 2009 in order to close the gap. This is not the type of performance that

[38] Reply Argument page 134

ratepayers would expect. OPG is not satisfied with its performance either: "... clearly we would like to see better performance from our plants."[39]

In its submission, Board staff included calculations of the cost of OPG's performance relative to the midpoint for comparators' total generating cost for 2011 for illustrative purposes. CME submitted that a $150M OM&A reduction per year was appropriate on the basis of this gap. The Board agrees with OPG that reductions of $150M to $300M per year on the basis of nuclear benchmarking is not appropriate as the impact of Business Transformation is not reflected in the 2011 total generating costs. However, the Board notes that OPG's total generating cost targets for 2014 and 2015 take into account Business Transformation and those targets are second and third quartile.

OPG also argued that the Board staff and CME calculations were flawed as there is unavoidable OM&A related to the CANDU technology. The Board does not agree that the calculations were flawed for this reason. The ScottMadden methodology, which has been accepted by OPG for benchmarking, considered technology differences and found that the best overall financial comparison metric for OPG facilities is total generating cost per MWh.

Both Environmental Defence and GEC have proposed significant reductions related to poor economic performance of the Pickering units. The Board does not agree with these submissions. The government's direction on the operation of Pickering is set out in the Long-Term Energy Plan.

The Board finds that OPG's proposed nuclear OM&A costs should be reduced. The Memorandum of Agreement provides that "OPG's top operational priority will be to improve the operation of its existing nuclear fleet." In conjunction with ScottMadden, OPG itself set targets for 2014 that will not be met. Although the Memorandum of Agreement is not a contract for this purpose, it is clearly OPG's shareholder's intention that OPG improve continually, and at least target top quartile performance. OPG accepts that benchmarking is a valuable tool, and accepts that it has not achieved the results it wanted to achieve. It does not appear to accept, however, that there should be any repercussions from this poor performance in the way of disallowances. Benchmarking serves as a guide only. However, it is clear that OPG's inability to achieve even average performance imposes a significant cost on ratepayers. The Board finds that it is not reasonable to pass all of these costs on to ratepayers.

[39] Tr Vol 6 page 13

There is no specific budget "line item" related to overall nuclear performance and benchmarking. However, the majority of OM&A costs are predominantly related to staffing levels, compensation and pension related costs. Therefore, the Board's disallowances with respect to this issue are incorporated within its disallowances under the compensation section of this Decision.

3.3 Nuclear Fuel

(Issue 6.5)

Nuclear fuel costs include the cost of fuel bundles, used fuel storage cost and fuel oil for standby generators. As updated in Exhibit N2, OPG has forecast an amount of $266.5M for nuclear fuel procurement for 2014 and $260.5M for 2015.

AMPCO submitted that based on the average of 2010 to 2013 actuals, the test period fuel oil expense should be reduced by $3.5M. OPG did not respond to this submission.

In response to direction from the previous cost of service decision, OPG filed the Uranium Procurement Program Assessment Study prepared by Longenecker and Associates ("Longenecker").[40] Longenecker confirmed that US nuclear generators require inventory of 30 to 35% of annual requirements. OPG stated that test period carrying costs would be reduced by $4.7M if OPG's inventory levels were reduced to 30%. CME submitted that a reduction of $4.7M is appropriate OPG argued that CME's proposal was unreasonable as contractual obligations as well as financial and physical risk coverage limits need to be considered.

CME observed that the proposed fuel costs are higher than historical and submitted that each test year be no more than the 2013 expense of $244.7M. OPG replied that there is no support for this submission as fuel expense is a function of production. In addition, OPG indicated that the 2013 fuel expense was based on production of 44.7 TWh and the production forecast for each test year is higher.

Board staff suggests that OPG be required as part of its next payments application to provide a study demonstrating how its nuclear fuel requirements and cost estimates reflect appropriate strategies for balancing costs and risks. Further, Board staff suggested that the analysis be based on the approaches that OPG has found

[40] Exh F5-2-1

BUSINESS PLANNING AND BENCHMARKING
NUCLEAR

1.0 PURPOSE

This evidence presents the business plan and benchmarking results for OPG's Nuclear Operations and provides a summary of nuclear operating costs in support of the application.

2.0 OVERVIEW

OPG's 2017-2021 rate application for its nuclear facilities is based on OPG's 2016-2018 Business Plan, including an additional three-year financial projection for the later years of the test period (2019-2021) both prepared on the same basis and through a consistent process (see Ex. A2-2-1 Attachment 1, Appendix 5: Nuclear Financial Plan, Operational Targets, and Initiatives, for further details). It is also aligned to the guiding principles of Ontario's 2013 Long-Term Energy Plan as it pertains to cost-effectiveness, reliability, clean energy, and community engagement.[1] This application reflects unprecedented and significant changes in OPG's nuclear operations which pose unique challenges in terms of business planning and benchmarking. These include the implementation of the Darlington Refurbishment Program ("DRP") and Pickering Extended Operations ("Extended Operations").

OPG's 2016-2018 Business Plan continues to achieve a sustainable cost structure for the nuclear operations by building on the success of major programs undertaken by OPG over the past few years, including; a) Pickering Continued Operations, where the work program was completed on time, on budget and is on plan to achieve 4-6 additional years of station operation to 2020, b) Business Transformation, where staffing targets were fully realized through the successful implementation of the program, and c) completion of various fleet-wide and site initiatives (Fuel Handling Reliablity, 3k3 Equipment Reliablity and Days Based Maintenance) that were focused on improving operational and cost performance. These initiatives are described in greater detail in section 3.5 below.

[1] Executive Summary, Ontario 2013 Long-Term Energy Plan as found at http://www.energy.gov.on.ca/en/ltep/achieving-balance-ontarios-long-term-energy-plan/

MWh associated with extensive additional planned outages for Pickering Extended Operations.

- For the human performance cornerstone, OPG is targeting improvement at Darlington, as indicated in the target reductions in the HPER over the 2016-2018 planning period. Pickering HPER is targeted to remain unchanged over this period.

Projected targets for the three key metrics of TGC/MWh, FLR and UCF for 2019-2021 are provided in Chart 5. These are challenging targets, which will require OPG to establish new initiatives based on future outcomes and operating conditions in order to achieve them.

Chart 5
Projected Targets for Key Metrics

Benchmarking Indicators	Pickering – Annual Targets			Darlington – Annual Targets		
	2019	2020	2021	2019	2020	2021
Safety						
Forced Loss Rate (%)	5.0	5.0	5.0	1.0	4.2	3.0
Unit Capability Factor (%)	72.6	73.4	70.6	87.8	79.4	90.9
Normalized Total Generating Cost per MWh ($/Net MWh)*	N/A	N/A	N/A	51.68	52.04	39.80
Total Generating Cost per MWh ($/Net MWh)*	78.36	74.93	81.16	64.61	73.82	64.90

* TGC/MWh and Non-Fuel Operating Cost per MWh exclude centrally held pension and OPEB costs and asset service fees to align with the industry standard.

Darlington's FLR in 2020 and 2021 is impacted by the assumed FLR for refurbished Unit 2 returning to service and is consistent with the assumptions that underpin the Darlington Refurbishment Execution Phase Business Case (Ex. D2-2-8 Attachment 1). The decline in Darlilngton's TGC/MWh in 2021 is largely explained by the expectation that two units will be subject to refurbishment in 2021. As a result there will be signficantly lower outage OM&A as there are no planned outages with the excepton of a short post refurbishment outage as described in Ex. E2-1-1.

APPENDIX 4: NUCLEAR FINANCIAL PLAN, OPERATIONAL TARGETS, AND INITIATIVES

Financial Plan

(in millions of dollars)	Forecast 2016	Business Plan 2017	Business Plan 2018	Business Plan 2019	Projection 2020	Projection 2021
OM&A						
Base*	1,172	1,196	1,215	1,254	1,263	1,281
Outage Incremental	319	392	373	343	328	322
Project Portfolio	94	111	91	82	82	87
Pickering Continued Operations Enabling Costs	15	26	55	107	104	-
Darlington Refurbishment Project	3	49	16	7	52	26
Nuclear New Build	1	2	7	10	11	11
Total Nuclear OM&A	**1,605**	**1,776**	**1,758**	**1,803**	**1,841**	**1,727**
Capital						
Project Portfolio (including Spares and Minor Fixed Assets)**	291	322	319	299	289	244
Darlington Refurbishment Project (excl. Support Services)	1,008	1,119	1,084	1,082	1,019	1,035
Total Nuclear Capital	**1,299**	**1,441**	**1,403**	**1,381**	**1,308**	**1,279**
Provision Expenditures						
ONFA Funded	85	150	147	206	264	325
Internally Funded - Base	101	115	115	122	125	127
Internally Funded - Projects	54	49	70	45	45	40
Internally Funded - Darlington Refurbishment Waste Containers	31	44	45	45	38	19
Total Nuclear Provision Expenditures	**272**	**358**	**377**	**418**	**471**	**511**
Fuel Expense (Pickering and Darlington)	**263**	**223**	**220**	**228**	**217**	**198**

* Includes an estimated $4M to $5M per year for work in support of the RG&PM business unit

** In 2019, includes $16M related to the load of new fuel bundles into the refurbished Darlington Unit 2

Operational Targets

The key 2017-2019 targets for the Nuclear business unit are set out below. These targets reflect the operating environment of the nuclear fleet, including refurbishment activities at the Darlington station and continuing work on fuel channel inspections at the Pickering station.

Metric	NPI Max	Industry Best Quartile	Pickering 2016 Target	Pickering 2016 Forecast	Pickering 2017 Target	Pickering 2018 Target	Pickering 2019 Target	Darlington[1] 2016 Target	Darlington[1] 2016 Forecast	Darlington[1] 2017 Target	Darlington[1] 2018 Target	Darlington[1] 2019 Target
All Injury Rate[2] (#/200k hrs worked)	N/A	0.69	0.24	0.49	0.24	0.24	0.24	0.24	0.23	0.24	0.24	0.24
Collective Radiation Exposure (person-rem/unit)	80.00	38.17	111.50	104.50	126.90	137.30	153.30	65.00	80.90	111.90	82.70	78.40
Unit Capability Factor (%)	92.0	91.3	77.6	75.3	71.5	72.0	72.6	91.1	90.0	85.1	86.0	87.8
Forced Loss Rate (%)	1.00	0.38	5.00	4.37	5.00	5.00	5.00	1.00	1.93	1.00	1.00	1.00
On-line Corrective Maintenance Backlog (work orders/unit)	N/A	7	55	80	28	28	28	20	20	15	10	7
WANO NPI (Index)	N/A	93.5	72.3	75.6	69.7	67.2	65.9	87.3	85.5	83.1	90.7	91.0
Human Performance Error Rate	N/A	0.0010	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030	0.0053	0.0020	0.0020	0.0020
Total Generating Cost per MWh[3]	N/A	$38.93	$71.09	$72.46	$78.83	$80.09	$81.49	$47.35	$46.46	$49.75	$49.54	$52.33

[1] Darlington targets reflect the impact of the Unit 2 Refurbishment starting in October of 2016, where applicable.

[2] Also applies to Darlington Refurbishment Project and Contractors.

[3] Metrics exclude centrally-held Pension and OPEB costs and asset service fees. Targets may change subject to allocations and assumptions being finalized. Darlington metrics have been normalized after 2016 for generation forgone during the Unit 2 refurbishment.

3. Objectives, Scope and Approach

Objectives and Scope

OPG asked ScottMadden to provide a written evaluation of its proposed methodology for normalizing two cost metrics that are used to track performance at DNGS. The goal of this normalization is to facilitate easier comparison to industry peers and pre-Refurb performance at DNGS for:

1) Total Generating Cost per MWh (TGC per MWh)
    - Numerator is Non-Fuel Operating Cost + Fuel Cost + Capital Cost
    - Denominator is the electrical energy generated and delivered to the grid, metered at DNGS
    - Metric represents total costs incurred per unit of net electrical production in the same period
2) Non-Fuel Operating Cost per MWh (NFOC per MWh)
    - Numerator is Non-Fuel Operating Cost. Denominator is the electrical energy generated and delivered to the grid, metered at DNGS
    - Metric represent Non-Fuel Operating Cost incurred per unit of net electrical production in the same period

ScottMadden's Approach

ScottMadden's approach to completing this evaluation can be broken down into six steps:

1) Understand and document exactly how OPG proposes to normalize these two cost metrics
2) Conduct research on comparable utility capital projects and related utility finance approaches to measure cost performance
3) Compare research findings to OPG approach
4) Develop and document ScottMadden evaluation of OPG approach
5) Send draft of evaluation to OPG for review
6) Finalize report

ScottMadden did not participate in the development of the proposed methodology but, to ensure completion of Step 1, did speak with internal OPG personnel and reviewed various internal OPG documents.

To complete Step 2, ScottMadden spoke with its internal nuclear experts and conducted research to identify other nuclear operators who could provide valuable operational experience (OpEx) for this evaluation. ScottMadden then conducted phone interviews with the following companies:

- NB Power
- Bruce Power
- Duke Energy

ScottMadden and these companies agreed to acknowledge and keep confidential any specific company information provided by OPG. OPG agreed to make every commercially reasonable effort to protect the confidentiality of any specific company information provided in response to the interviews.

Board Staff Interrogatory #101

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

Interrogatory

Reference:
Ref: Exh F2-1-1 page 3 and 16

At page 16 of the reference, it states:

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

a) Please provide the Nuclear Operations internal performance targets for TGC/MWh, on a non-normalized basis or note whether the internal targets are provided in the nuclear business plan filed in response to a previous interrogatory.

b) Please provide the details of the normalized TGC calculation.

c) Is normalizing TGC standard practice for utilities during major nuclear refurbishments?

d) In 2015, ScottMadden validated the ongoing appropriateness of OPG's application of the benchmarking methodology. Was ScottMadden consulted about normalizing TGC during the DRP, and if yes, what was their feedback?

Response

a) The non-normalized TGC/MWh is included in Ex. F2-1-1 Chart 4 (p. 15) and Chart 5 (p. 17).

b) The denominator in TGC/MWh declines as noted in the evidence reference as the planned Darlington units are being refurbished. TGC/MWh is normalized by adding back to the denominator the deemed generation had refurbishment not taken place:

1. Added back generation based on duration of refurbishment (e.g., 365 days X 878 MW X 24 hours).
2. Adjusted for regular scheduled outage (i.e., Unit 2 would have a regularly scheduled outage in 2019 if it were not being refurbished)
3. Adjusted for forced losses based on Darlington's expected forced loss rate (FLR) of 1% instead of the post refurbishment targeted FLRs.

The numerator has been adjusted for higher fuel costs as a result of normalizing the generation. Fuel costs are adjusted based on Total Fuel Bundle Cost and Used Fuel Storage & Disposal costs per Ex. F2-5-1 Table 1.

c) & d) ScottMadden's evaluation of OPG's approach to normalizing TGC/MWh during DRP is attached as Attachment 1. ScottMadden found OPG's normalization approach to be unique but logical, reasonable, and easy to understand.

ScottMadden Evaluation of OPG Proposed Approach to Normalize Cost Metrics During Darlington Refurbishment

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MANAGEMENT CONSULTANTS

4. Assumptions and Qualifications

Assumptions

In preparing this evaluation, ScottMadden made the following assumptions:

- OPG will continue to report an unadjusted (i.e., not normalized) version of these cost metrics in conjunction with any normalized version
- Documents OPG has shared with ScottMadden reflect current plans for normalization of the cost metrics to be evaluated (TGC/MWh and NFOC/MWh) as of the date of this report
- Information provided by personnel from other companies accurately reflects what was (or would be) their approach to normalizing cost metrics in a comparable situation

Qualifications

ScottMadden's evaluation is subject to the following qualifications:

- Refurb is a unique "mega-project," and the experience and perspective of other industry professionals, while useful to consider, cannot provide established practice for normalizing cost metrics during this unique project
- This evaluation is based solely on the approach described in this document, and ScottMadden does not imply the performance of any additional, specific research
- The ScottMadden evaluation of the OPG approach to normalizing these cost metrics was prepared for the benefit of OPG and is limited to the subject matter expressly stated in this document; no additional ScottMadden opinion is implied or may be inferred
- ScottMadden does not express an opinion in this document on the:
  - Effectiveness of cost management practices at OPG
  - Appropriateness of any costs incurred by OPG

5. Evaluation and Summary

Evaluation

ScottMadden concurs with OPG that Refurb will significantly impact station performance indicators for these two cost metrics and that normalization will be necessary to facilitate useful comparisons to past performance and industry peers.

ScottMadden supports OPG's decision to continue to report an unadjusted (i.e., not normalized) version of these cost metrics in conjunction with any normalized version.

ScottMadden observed that OPG evaluated a robust list of the options available in selecting its normalization approach to these cost metrics, including:

- Adjust numerator (cost)
  - Adjust up – Increase fuel cost using historical cost data on the assumption that no units are offline during refurbishment
  - Adjust down – Reduce fixed costs using allocation factors on the assumption that actual costs do not scale up or down with generation
  - Do not adjust – Make no adjustment to cost

- Adjust denominator (MWhs generated)
  - Adjust up – Increase MWhs using historical data and forced-loss rate (FLR) projections, on the assumption that no units are offline for Refurb
  - Adjust down – Not considered
  - Do not adjust – Make no adjustment to MWhs generated

OPG selected its preferred normalization approach by measuring each option against six criteria:

- Understandability – how easy is it to describe how the metric was normalized?
- Ease of calculation – how easy would it be to perform the normalization and calculate this metric as Refurb continues?
- Protection from understatement – is there sufficient protection from making performance look better than it is through changes to the numerator or denominator?
- Acceptance by station management – would station management believe the metric is reflective of true performance and use it to pursue improvement?
- Acceptance by executive oversight – would OPG management believe the metric is reflective of true performance and use it to pursue improvement?
- Acceptance by external stakeholders – would external stakeholders believe the metric is reflective of true performance and use it to pursue improvement?

ScottMadden believes this is an appropriate set of criteria for selecting a normalization approach that facilitates useful comparisons to past performance and industry peers. Ultimately, the normalized metrics must support effective ongoing performance monitoring and improvement, and, as such, ease of calculation is the least important criterion of the group.

ScottMadden views OPG's current normalization approach for these metrics, as detailed in the Appendix, as unique but logical, reasonable, and easy to understand.

The ScottMadden observations that OPG should consider as supportive of its current normalization approach include:

- Significant historical data on fuel cost is available for use in "normalizing up" the numerator
- Significant historical data on MWhs of generation is available for use in "normalizing up" the denominator
- The current normalization approach is relatively easy to understand and calculate
- The top industry cost organization (the Electric Utility Cost Group or EUCG) allows nuclear operators who were available to generate MWhs but did not do so at the request of the market operator to submit those MWhs as if they generated the MWhs

The ScottMadden observations that OPG should consider as not supportive of its current normalization approach include:

- Allocation of corporate and nuclear support costs to DNGS still inflate the numerator
- OpEx from other companies did not support "normalizing up" costs in the numerator and was focused instead on adjusting the distribution of actual costs to reflect performance

- OpEx from other companies did not support "normalizing up" MWhs in the denominator
  - Other companies used actual MWhs generated (or available to generate) in every case
  - In the noted case where MWhs available to generate were included (see supportive observations above), the unit was operational and the period was hours or days rather than months or years, which is the case with Refurb
  - Other companies did not include potential MWhs in the calculation when a unit was offline due to a capital project

Summary

OPG asked ScottMadden to provide a written evaluation of its proposed methodology for normalizing Total Generating Cost per MWh (TGC per MWh) and Non-Fuel Operating Cost per MWh (NFOC per MWh), both of which are used to track performance at DNGS. The goal of this normalization is to facilitate easier comparison to industry peers and pre-Refurb performance at DNGS. ScottMadden performed the evaluation according to the approach described in this document and subject to the listed assumptions and qualifications. One noteworthy qualification is that Refurb is a unique "mega-project," and the experience and perspective of other industry professionals, while useful to consider, cannot provide established practice for normalizing cost metrics during this unique project.

ScottMadden concurs with OPG that Refurb will significantly impact station performance indicators for these two cost metrics and that normalization will be necessary to facilitate useful comparisons to past performance and industry peers. ScottMadden also supports OPG's decision to continue to report an unadjusted (i.e., not normalized) version of these cost metrics in conjunction with any normalized version. Further, ScottMadden observed that OPG evaluated a robust list of the options available in selecting its normalization approach and assessed these options against an appropriate set of criteria for selecting a normalization approach that facilitates useful comparisons to past performance and industry peers.

ScottMadden views OPG's current normalization approach for these metrics, as detailed in the Appendix, as unique but logical, reasonable, and easy to understand. These normalized measures can facilitate useful comparisons to past performance and industry peers. And, if the normalized measures are accepted by management and external stakeholders, they can be used to drive performance monitoring and improvement. ScottMadden's evaluation found that, while Refurb is a unique mega-project, a more strongly supported and conventional approach to normalization of cost metrics under comparable scenarios was to adjust the distribution of actual costs to reflect performance of the operating units while using actual MWhs generated in the denominator.

3.0 NUCLEAR BUSINESS PLANNING AND BENCHMARKING

3.1 Gap-Based Business Planning Process

OPG's Nuclear business planning cycle is undertaken annually as part of and consistent with the overall OPG business planning process (see Ex. A2-2-1). The business planning process is focused on establishing strategic and performance targets for nuclear, in alignment with OPG's objectives, and identifying the initiatives and resources required to achieve these targets.

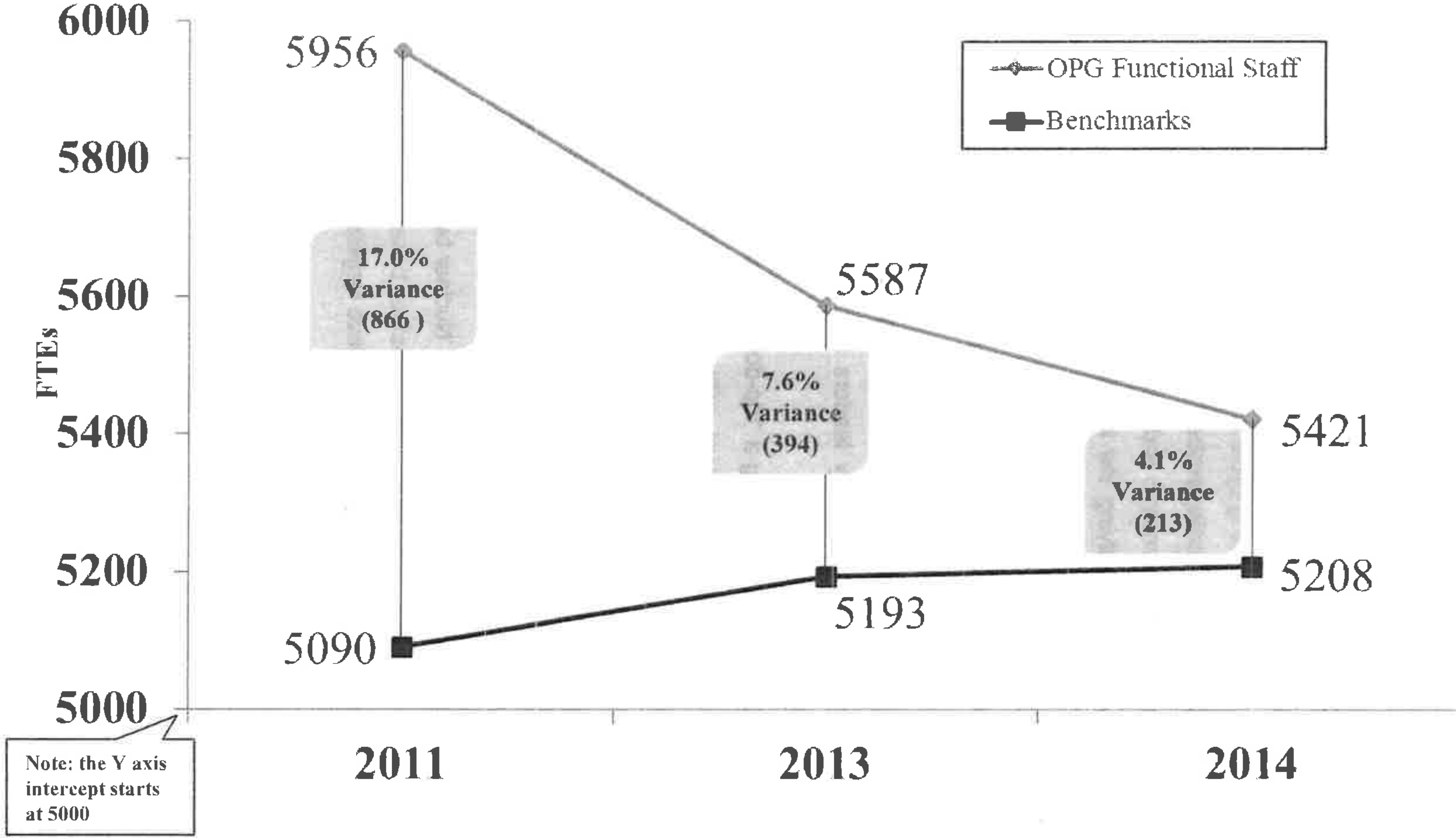
Since 2009, OPG nuclear has used a gap-based business planning process which consists of the following steps:

- **Benchmarking:** Using industry accepted performance metrics, compare nuclear performance against industry leaders in order to identify areas with the greatest potential for improvement.
- **Target Setting:** Implementing a "top-down" approach to set operational and financial performance targets consistent with continuous improvement and informed by benchmarking.
- **Closing the Gap:** By reference to OPG Nuclear's four cornerstone values of Safety, Reliability, Human Performance and Value for Money, developing various fleet wide and site specific initiatives to close the performance gaps between current and targeted results.
- **Resource Planning:** Preparing an OPG Nuclear business plan (i.e., the development of cost, staff and investment plans) that is based on the "top-down" targets and incorporates initiatives necessary to achieve targeted results.

3.2 Gap-Based Business Planning – Benchmarking

The 2015 Nuclear Benchmarking Report benchmarks OPG's performance against industry peers based on 2014 data and uses 20 indicators aligned with the cornerstone values of Safety, Reliability, Value for Money and Human Performance (see Attachment 1 to this exhibit). The 2015 Nuclear Benchmarking Report uses the same methodology and format as

Attrition, OPG Actions, & Increases In The Benchmark Have Reduced OPG's Variance From The Benchmark



The Center-Led Initiative involved a major reorganization effort, decreasing staffing in a number of functions since 2011, most notably Management.

The Pickering Station amalgamation helped OPG achieve efficiencies and improve variances from the benchmark in a number of functions since 2011.

As Pickering approaches shutdown, the attrition rate has increased as more personnel retire early and some vacant positions go unfilled.

GOODNIGHT CONSULTING

Highlights of OPG's 2016-2018 Business Plan as it pertains to Nuclear Operations include the following:

- OPG has been successful in achieving Business Transformation targets through attrition. Higher than anticipated attrition has eliminated the gap associated with Goodnight[2] staffing benchmarks in 2016. The business plan and three-year financial projection address the challenges ahead and focus on addressing the emerging labour supply versus demand gap, leadership capability and key resource availability to ensure safe and efficient operations of OPG's nuclear facilities, while minimizing risks to the efficient execution of Pickering Extended Operations and the DRP.
- Maintaining high standards of safety and environmental stewardship with a focus on keeping Airborne Tritium Emissions as low as reasonably achievable.
- Implementation of Extended Operations to extend the life of all six Pickering units until 2022 and four units until 2024.
- Continued planning to develop a Pickering End of Commercial Operations and Decommissioning Strategy.
- An initiative to improve equipment reliability at both Pickering and Darlington with a particular focus on fuel handling to ensure that we achieve aggressive forced loss targets that improve generation efficiency.
- Implementation of human performance improvement plans at the nuclear fleet and station levels to focus on worker safety and plant operation, including increased supervisory effectiveness and field oversight, focusing on error prevention to reduce forced outages and improve production levels, thereby lowering Total Generating Cost per MWh ("TGC/MWh").
- Executing project portfolio investments to enhance the performance, reliability and overall value of OPG's Nuclear assets. This includes increased capital investment primarily at Darlington to undertake aging equipment projects and certain Facilities and Infrastructure Projects determined to be necessary to support Darlington operations before, during and post-refurbishment (see Ex. D2-2-10 and Ex. D2-1-2 section 3.1).

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[2] See section 3.3 of this exhibit for further discussion of Goodnight staff benchmarking.

5,421 OPG Employees & Contractors Were Functionalized For Benchmarking

	Employees	Contractor FTEs	Grand Total
Assurance	36	0	36
Business & Admin Services	570	71	641
Commercial Operations & Environment	33	0	33
Corporate Relations & Communications	16	0	16
Finance	66	1	67
Nuclear	3606	305	3911
Nuclear Projects	199	114	313
People and Culture	364	41	405
Grand Total	**4890**	**531**	**5421**

This data is organized by OPG Business Group; employees supporting various job functions are found within each Business Group, for example the "People & Culture" Business Group includes Training, HR, and Support staff

	Regular	Contractor	Grand Total
Configuration Control	310	35	345
Equipment Reliability	406	36	442
Loss Prevention	268	35	303
Materials & Services	187	21	208
Operate The Plant	1055	17	1072
Support Services & Training	1013	136	1149
Work Management	1651	251	1902
Grand Total	**4890**	**531**	**5421**

This data is organized by Goodnight Consulting Process Area.

A line-by-line accounting of where each employee was functionalized is provided in the Appendix

GOODNIGHT CONSULTING

2,036 OPG Nuclear Personnel Could Not Be Benchmarked

CANDU-Specific Exclusions*

- *Fuel Handling*: Comparable function in PWRs only occurs during outages
- *Heavy Water Handling*
- *Tritium Removal Facility*
- *Feeder and Fuel Channel Support*
- *Other CANDU-Specific support to excluded functions e.g. Refueling Ops*

*Unique to CANDU design with no comparable PWR activity

OPG-Specific Exclusions

- *Pickering Units 2 & 3 Safe Store Support*: However, cross-tied operations for Units 2 & 3 ***were counted***
- *Major Projects/ One time initiatives*: e.g., Darlington Refurbishment, New Build, etc.

Generic Exclusions**

- *Nuclear waste and used fuel*: Functions not performed by plants in the benchmark
- *Outage execution activities*: Less than 10% were applied as "on-line“ support to various functions
- *Water treatment*: Functions not performed by plants in the benchmark

**Both CANDU & PWR activities but excluded as non-baseline/non-steady state

Other Exclusions

- *Security*: Excluded consistent with OPG Security policy
- *Information Management*: Benchmarked via a different method external to this study
- *Long Term Leave Personnel*: Excluded consistent with Goodnight Consulting benchmarking methodology
- *Corporate Support Not Directly Supporting The Nuclear Program*: Excluded consistent with Goodnight Consulting benchmarking methodology

GOODNIGHT CONSULTING

Board Staff Interrogatory #109

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

Interrogatory

Reference:
Ref: Exh F2-1-1 Attachment 2 page 3 and 11 Ref: Exh F4-3-1 Attachment 1

At page 3, it states, "We benchmarked 5,421 OPG Nuclear staff and long-term contractors; 2,036 OPG Nuclear personnel could not be benchmarked."

a) Confirm that these data units are FTE, as used in the balance of the Goodnight report.

b) What is the definition of long-term contractor? What is the equivalent term used by OPG?

c) The total nuclear staff referred to by Goodnight is 7,457 FTE, presumably at March 2014. Attachment 1 to Exh F4-3-1 is a table summarizing FTE for the period 2013 to 2021. The total actual nuclear FTE for 2014 are 8,431.8.
   i. At page 11, Goodnight states that an FTE is 1,890 hours/year (or 36-1/3 hours per week). What factor did OPG use to determine FTE in Attachment 1 to Exh F4-3-1?
   ii. While the FTE data were collected at different times in 2014, please explain the approximately 1,000 FTE difference between the 7,457 FTE referred to in the Goodnight study and the 8,431,8 FTE summarized in Attachment 1 to Exh F4-3-1.
   iii. Using the same categories as lines 3 to 22 Attachment 1 to Exh F4-3-1, please set out the distribution of the 5,421 FTE that were benchmarked by Goodnight.

Response

a) Goodnight data is a combination of regular staff headcount translated into FTEs and long-term contractor FTEs at March 2014.

b) Goodnight Consulting defines a long-term contractor as non-regular staff or purchased services contractors of 6 months or longer duration (Goodnight report at EB-2013-0321 Ex. F5-1-1 Part a, p. 39). OPG does not distinguish between short term and long term contractors in its contractor support services (see definition of non regular labour, augmented staff and other purchase services in Ex. F2-4-1, p. 4).

c) Goodnight refers to 7,457 FTEs, which represent 6,926 regular staff, 195.3 non-regular staff contractor FTEs and 335.7 purchased services contractor FTEs.

i. More specifically, Goodnight is referring to an annual factor of 1,890 hours per year to calculate FTEs for purchased services contractors.

The FTEs in Attachment 1 to Ex. F4-3-1 were determined based on the weekly base hours associated with each position over the course of the year. Different factors were used depending on the base hours of work associated with each regular staff position as follows:

- For an employee whose base hours of work are 35 hours per week, an annual factor of 1,820 hours per year was used
- For an employee whose base hours of work are 37.5 hours per week, an annual factor of 1,950 hours per year was used
- For an employee whose base hours of work are 40 hours per week, an annual factor of 2,040 hours per year was used

ii. The difference of 974.8 FTEs from the 7,457.0 Nuclear FTEs in the Goodnight study to the 8,431.8 actual FTEs for 2014 in Ex. F4-3-1 Attachment 1 is shown in Chart 1 below:

Chart 1

	Total FTEs
Goodnight March 2014 Reported Total	7,457.0
Less: Augmented Staff + Other Purchased Services	(335.7)
Plus:	
Non-Regular Staff Not Benchmarked + Security Protected Staff Excluded + Other (timing differences, etc)[1]	765.0
Indirect Corporate Staff	545.4
Ex. F4-3-1 Attachment 1 2014 Actual	8,431.8

The Goodnight study identified 7,457.0 Nuclear FTEs, consisting of 6,926.0 Regular Staff and 531.0 Contractors. Of the 7,457.0 Nuclear FTEs, Goodnight was able to benchmark 4,890.0 Regular Staff FTEs and the 531.0 Contractor FTEs engaged in baseline steady state operations, for a total of 5,421.0 FTEs. The 531.0 Contractor FTEs in the Goodnight study represent Non–Regular Staff, Augmented Staff and Other Purchase Services. Goodnight was

[1] Provided on an aggregated basis, as OPG is unable to disclose information separately for Security Protected Staff.

unable to benchmark the remaining 2,036.0 Regular Staff FTEs as described at Ex. F2-1-1 Attachment 2, p. 14.

The 8,431.8 FTEs identified in Ex. F4-3-1 Attachment 1 also includes Non-Regular Staff FTEs but excludes 335.7 Augmented Staff and Other Purchase Services FTEs, which have been subtracted in the reconciliation in Chart 1.

The other reconciliation items in Chart 1 include adjustments for:

- 765.0 FTEs for Non-Regular Staff Not Benchmarked, Security Protected Staff Excluded, and Other:
  - Non-regular staff engaged in non-benchmarked activities, primarily outage execution (Ex. F2-2-1 Attachment 2, p. 10). These non-baseline, non-regular staff FTEs were excluded from the 7,457.0 FTES analysed by Goodnight but have been included in the 8,431.8 FTEs.
  - Security Protected Staff. The number of security personnel working at OPG is confidential and therefore OPG did not provide information on Security Protected Staff FTEs to Goodnight. Security Protected Staff are excluded from the 7,457.0 FTEs but have been included in the 8,431.8 FTEs.
  - Other (e.g. timing differences). Goodnight derived FTEs based on March 2014 headcount whereas the 8,431.8 FTEs reflect actual 2014 FTEs.
- 545.4 FTEs for Direct versus Indirect Corporate Staff:
  - Goodnight benchmarked those Corporate Staff directly supporting Nuclear (e.g., Nuclear Finance). Corporate Staff that indirectly support Nuclear (e.g., Treasury) were excluded from Goodnight but have been included within the 8,431.8 FTEs.

iii. Of the 5,421 FTEs benchmarked by Goodnight, these include 335.7 purchased services contractor FTEs, which are not represented in Ex. F4-3-1 Attachment 1. Therefore, 5,085.3 regular and non-regular benchmarked FTEs can be distributed according to the format of Ex. F4-3-1 Attachment 1 lines 3 to 22:

Line No.	**NUCLEAR FACILITIES**	**Goodnight 2014 Study Benchmarked**
1	**Staff** (Regular and Non-Regular)	**FTEs**
2		
3	**Nuclear - Direct**	
4	Management	271.2
5	Society	1,281.3
6	PWU	2,335.7
7	EPSCA	42.5
8	Subtotal	3,930.7
9		
10	**Nuclear - Allocated**	
11	Management	148.0
12	Society	335.7
13	PWU	671.0
14	EPSCA	0.0
15	Subtotal	1,154.6
16		
17	**NUCLEAR FACILITIES**	
18	Management	419.2
19	Society	1,617.0
20	PWU	3,006.6
21	EPSCA	42.5
22	Total	5,085.3
	Contractor FTEs Purchased Services	335.7
	Total	5,421.0

	FTEs	a 2014 Actual	b 2014 Goodnight	Notes
1	**Nuclear - Direct**			
2	Management	553.1	271.2	
3	Society	1,922.2	1281.3	
4	PWU	4,002.4	2335.7	
5	EPSCA	69.6	42.5	
6	Subtotal	6,547.3	3930.7	
7	**Nuclear - Allocated**			
8	Management	376.0	148.0	
9	Society	625.6	335.7	
10	PWU	882.8	671.0	
11	EPSCA	0.0	0.0	
12	Subtotal	**1,884.4**	**1154.7**	
13	**Nuclear Total**			
14	Management	929.1	419.2	
15	Society	2,547.8	1617.0	
16	PWU	4,885.2	3006.7	
17	EPSCA	69.6	42.5	
18	**TOTAL**	**8,431.8**	**5085.4**	
19	**Purchased Service Contractor FTEs**	335.7	335.7	Goodnight benchmarked 531 baseline contractor FTEs. In response to L-6.2-Staff-109, OPG stated that 335.7 contractor FTEs benchmarked by Goodnight were not included in Exh F4-3-1 Attachment 1
20			**5421.1**	Goodnight benchmarked 5421.1 OPG Nuclear FTEs (4890 employees + 531 contractors)
21			2,036.0	Goodnight could not benchmark 2036 nuclear personnel. Exh F2-1-1 Attachment 2 page 14: CANDU specific exclusions, OPG specific exclusions (e.g. DRP), generic exclusions (e.g. nuclear waste and used fuel), other (e.g. security, information management, long term leave personnel, corporate support not directly supporting the nuclear program).
22	**TOTAL (OPG + Contractors)**	**8,767.5**	**7,457.1**	The difference in FTEs: 8767.5 - 7457.1 = 1310.4 In response to L-6.2-Staff-109 (updated Feb 10, 2017), 765 FTEs (non regular staff not benchmarked, Security Protected Staff, Other (timing differences) 545.4 FTEs (indirect corproate staff, e.g. Treasury)

Column a data, lines 1-18, from Exh F4-3-1 Attachment 1 "FTE (Regular and Non-Regular) Information for OPG's Nuclear Facilities"
Column b data from L-6.2-Staff-109

AMPCO Interrogatory #92

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

Interrogatory

Reference:
Ref: D2-2-8 Attachment 4 Page 27

a) Please quantify the % of costs associated with the full time operation of Darlington that remains during the test period by year and show the calculation.

Response

Chart 1 compares the Darlington operating costs in the test period to 2015 actual operating costs. Darlington operating costs reflect amounts shown in L-6.2-15 SEC-63 part (b), Chart 1 for Stations and Nuclear Support for 2017-2021.

Chart 1

Line No.	($M)	2015	2017	2018	2019	2020	2021
		(a)	(b)	(c)	(d)	(e)	(f)
1	Total Darlington Operating Costs	694.6	723.4	686.0	681.4	725.4	588.5
2	Forecast Darlington Operating Costs as a % of 2015		104.1%	98.8%	98.1%	104.4%	84.7%

The majority of costs associated with the full-time operation of Darlington remain fixed as many of the functions that support the operation of all four units continue to be required during refurbishment to support the operation of a multi unit station even while units are on refurbishment outages. Examples of operating costs that remain even if one unit is in refurbishment include:

- Operating and maintaining safety systems and other common systems (i.e., Unit 0).
- Tritium removal facility that supports the remaining operating units, Pickering and other nuclear plants as well as other common facilities (e.g., water treatment plant).
- Fuel handling maintenance and operations to support fueling of the remaining operating units as well as fueling of the units undergoing refurbishment. Costs of defueling of the refurbishment units are included in DRP.

- Support, planning and contract oversight for work being performed within the station, except on the refurbishment units (the DRP will perform the oversight for the refurbishment unit).
- Operator training to ensure long term operability of the four units.
- Equipment inspections that are required on a periodic basis.
- Measurement, monitoring and reporting of environmental emissions.
- Security, nuclear programs, nuclear oversight, engineering and other nuclear support costs. Incremental security costs for the Refurbishment security entrance are funded by the DRP.

In addition, OPG has a comprehensive plan to perform non-refurbishment maintenance work on the unit that is offline. OPG cannot meaningfully allocate costs between the costs of such work and the other costs required to support the operation of the four-unit station. This work includes preventative and corrective maintenance work that would normally be done during scheduled outages but will be spread over the refurbishment period while a unit is on a refurbishment outage.

Note that total Darlington costs fluctuate year over year for a variety of reasons and in some years (e.g., 2017 and 2020), are higher than 2015 due to the outage program, additional inspection programs such as single fuel channel inspections, and specific life cycle management work. A description of year over year changes for base OM&A, project OM&A and outage OM&A costs can be found in Ex. F2-2-2, Ex. F2-3-2, and Ex. F2-4-2.

Board Staff Interrogatory #141

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

Interrogatory

Reference:
Ref: Exh A2-2-1 page 2 Attachment 1 page 15 Ref: Exh F2-1-1 Table 3

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

a) At page 2 of Exh A2-2-1, it states that the planning assumptions include Pickering 2022/2024. If so, why are there reductions in staffing levels in 2019-2021?

b) Does the business plan and the nuclear staff summary reflect the allocation of Darlington staff, from units undergoing refurbishment, to Pickering?

Response

a) OPG's staffing plans are based on the assumption that the Pickering station will operate until 2022/2024. However, the company's staffing strategy is to reduce headcount, where possible, in advance of the shut down. This applies to both direct and support organization and costs such as inspection, maintenance, engineering and corporate support services, which will start to ramp down staffing gradually in advance of the units closing.

b) There are no Darlington staff from units undergoing refurbishment allocated to Pickering in the 2016-2018 Business Plan or the nuclear staffing summary.

Numbers may not add due to rounding.

Table 1
Operating Costs Summary - Nuclear ($M)

Line No.	Cost Item	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	OM&A:									
	Nuclear Operations OM&A									
1	**Base OM&A**	1,127.7	1,127.1	1,159.6	1,201.8	1,210.6	1,226.0	1,248.4	1,264.7	1,276.3
2	**Project OM&A**	105.7	101.9	115.2	98.2	113.7	109.1	100.1	100.2	86.8
3	**Outage OM&A**	277.5	221.3	313.7	321.2	394.6	393.8	415.3	394.4	308.5
4	**Subtotal Nuclear Operations OM&A**	1,510.8	1,450.3	1,588.5	1,621.3	1,718.9	1,728.9	1,763.8	1,759.4	1,671.6
5	**Darlington Refurbishment OM&A**	6.3	6.3	1.6	1.3	41.5	13.8	3.5	48.4	19.7
6	**Darlington New Nuclear OM&A**[1]	25.6	1.5	1.3	1.2	1.2	1.2	1.2	1.3	1.3
7	**Allocation of Corporate Costs**	428.4	416.2	418.8	442.3	448.9	437.2	442.7	445.0	454.1
8	**Allocation of Centrally Held and Other Costs**[2]	413.5	416.9	461.0	331.9	80.2	118.2	108.3	91.1	81.3
9	**Asset Service Fee**	22.7	23.3	32.9	28.4	27.9	27.9	28.3	22.9	20.7
10	**Subtotal Other OM&A**	896.5	864.1	915.5	805.0	599.7	598.3	584.1	608.6	577.1
11	**Total OM&A**	2,407.3	2,314.5	2,504.0	2,426.3	2,318.6	2,327.1	2,347.9	2,368.0	2,248.7
12	**Nuclear Fuel Costs**	244.7	254.8	244.3	264.8	219.9	222.0	233.1	228.2	212.7
	Other Operating Cost Items:									
13	**Depreciation and Amortization**	270.1	285.3	298.0	293.6	346.9	378.7	384.0	524.9	338.1
14	**Income Tax**	(76.4)	(61.5)	(31.8)	(16.7)	(18.4)	(18.4)	(18.4)	51.2	51.7
15	**Property Tax**	13.6	13.2	13.2	13.5	14.6	14.9	15.3	15.7	17.0
16	**Total Operating Costs**	2,859.3	2,806.2	3,027.8	2,979.4	2,881.6	2,924.4	2,961.9	3,187.9	2,868.2

Notes:

1 Nuclear Operations expenditures to maintain the Nuclear New Build option. In addition there are allocated corporate costs (included in line 7) for Nuclear New Build of $0.8M in 2016, $1.1M in 2017, $0.2M in 2018, $0.5M in 2019, $0.5M in 2020 and $0.5M in 2021.

2 Comprises centrally-held costs from Ex. F4-4-1 Table 3 and amounts of approximately $1M-$6M per year for machine dynamics and performance testing services provided by Hydro Thermal Operations in support of Nuclear Operations.

Chart 1: Nuclear Deficiency for 2017 - 2021 Period

Line No		($M) 2017	($M) 2018	($M) 2019	($M) 2020	($M) 2021	Reference
1	**EB-2013-0321 Average Approved 2014 & 2015 Revenue Requirement**	**2,834.0**	**2,834.0**	**2,834.0**	**2,834.0**	**2,834.0**	Note 1a
2	Revenue at EB-2013-0321 Payment Amount ($59.29/MWh)	**2,258.9**	**2,280.9**	**2,313.9**	**2,214.8**	**2,097.9**	Note 2a
3	Lower Production (line 1 - line 2)	**575.2**	**553.1**	**520.2**	**619.2**	**736.1**	
	Changes in Revenue Requirement:						
4	Darlington Refurbishment	46.7	(15.9)	(51.0)	487.9	519.3	Note 3a
5	Pickering Extended Operations Enabling Costs	25.6	55.3	107.1	104.3	0.0	Ex. F2-2-3 Chart 2
6	Impact of Changes in Nuclear Station End-of-Life Dates on Nuclear Liabilities	31.8	36.2	42.2	129.7	132.2	Ex. C2-1-1 Table 5, line 18
7	Impact of Changes in Nuclear Liabilities Reflecting 2017 ONFA Reference Plan	(22.9)	(32.8)	(3.7)	(84.8)	(127.0)	Ex. N1-1-1 Chart 3.2.1 line 8
8	Remaining Depreciation and Amortization Expense *(other than lines 4, 6 & 7)*	99.9	136.9	143.7	132.4	(141.7)	Note 4a
9	Outage OM&A Expenses *(other than line 5)*	75.8	59.8	29.9	12.2	11.8	Note 5a
10	Remaining/Other OM&A Expenses *(other than lines 4, 5, 6, & 7)*	81.8	103.5	164.4	182.2	194.6	Note 6a
11	Fuel Costs *(other than lines 6 & 7)*	(49.8)	(47.8)	(37.5)	(41.4)	(56.7)	Note 7a
12	Other	38.6	61.5	54.2	42.3	51.9	Note 8a
13	**Total Change in Revenue Requirement** (lines 4 through 12)	**327.4**	**356.6**	**449.4**	**964.8**	**584.4**	
14	**Total Revenue Deficiency** (line 3 + line 13)	**902.5**	**909.7**	**969.5**	**1,584.0**	**1,320.5**	

Notes

1a Ex. I1-1-1 Table 2, Line 11

OEB APPROVED 2014	OEB APPROVED 2015	AVERAGE
2,790.4	2,877.6	2,834.0

2a

REDUCED PRODUCTION	2017	2018	2019	2020	2021
Test Period Production (Ex E2-1-1 Table 1, line 3, cols. (e) to (i)) **(TWh)**	38.1	38.5	39.0	37.4	35.4
Nuclear Base Payment Amount (EB-2013-0321 Payment Amount Order, App D, line 3) **($/MWh)**	$59.29	$59.29	$59.29	$59.29	$59.29
Forecast Revenue ($M)	2,258.9	2,280.9	2,313.9	2,214.8	2,097.9

OUTAGE OM&A – NUCLEAR

1.0 PURPOSE

This evidence presents nuclear operations outage OM&A costs for the period 2013 - 2021.

2.0 OVERVIEW

Outage OM&A costs vary year over year depending on the number and scope of outages and therefore cannot be trended over time. Chart 1 below shows the cost, frequency and nature of nuclear outages during the 2013 to 2021 period. The test period outage OM&A expense is $394.6M in 2017, $393.8M in 2018, $415.3M in 2019, $394.4M in 2020 and $308.5M in 2021, and forms part of the OM&A expense in the nuclear revenue requirement.

Outage OM&A costs over the test period primarily reflect the following:

- Outage OM&A costs to complete Darlington unit outages for the three year planned outage schedule for routine inspection and maintenance. This includes outage costs for units laid up during refurbishment (e.g., Unit 2 during 2016-2020), which will be subject to inspection and maintenance activities over the period 2017-2019 associated with a planned outage in accordance with OPG's aging and life cycle management programs, in addition to and separate from the refurbishment of the units. The outage work in 2017-2019 effectively replaces two scheduled planned outages for Unit 2 in 2016 and 2019 which would otherwise have been undertaken absent Unit 2 refurbishment.
- Darlington Unit 2 is scheduled to return to service in February 2020 following refurbishment. OPG has scheduled two post refurbishment mini planned outages to address any issues expected to arise after the major refurbishment is complete and the unit has resumed operations.
- Outage OM&A costs to complete Pickering unit outages for the two year planned outage schedule for routine inspection and maintenance. The cost for each of the planned outages for the period 2017-2020 also includes the additional scope added for Pickering Extended Operations which is required to enable Pickering's operation to 2022/2024. In addition, the Unit 7 outage in 2020 is being undertaken solely for

Board Staff Interrogatory #096

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

Interrogatory

Reference:
Ref: Exh F2-4-1 page 1
Outage OM&A cost for Darlington in the test period include, "outage costs for units laid up during refurbishment (e.g., Unit 2 during 2016-2020), which will be subject to inspection and maintenance activities over the period 2017-2019 associated with a planned outage in accordance with OPG's aging and life cycle management programs, in addition to and separate from the refurbishment of the units."

a) Why are these inspection and maintenance activities separate from refurbishment?

b) What is the purpose of the aging and life cycle management programs for units undergoing refurbishment? Are the programs required by the CNSC? Please provide examples of aging and life cycle management programs.

Response

(a) These inspection and maintenance activities are separate from refurbishment because they are required as part of the ongoing maintenance and operation of the plant and are required to be performed even while the unit is being refurbished.

Examples of these inspection and maintenance activities, which are typical of regular planned outages at Darlington or Pickering, are set out in OPG's response to part (b) below.

In contrast, Darlington Refurbishment Program ("DRP") scope is defined as the replacement of station life limiting components, regulatory and safety improvements and other work best performed during an extended refurbishment outage as well as incremental facilities and infrastructure required for DRP to complete the above scope.

(b) As identified above, the DRP has a defined scope of work limited to specific systems and components. The remaining systems and components not included as part of DRP scope require ongoing inspection, maintenance, repair and replacement as defined by station aging and life cycle management programs for those systems and components.

The purpose of these programs is to ensure equipment is meeting safety and reliability standards and requirements. Some programs are required by the CNSC, which typically include periodic inspections and preventative maintenance programs on safety related equipment. Some investments are required to ensure the plant runs optimally and meets performance expectations. Examples of maintenance activities as per the stations aging and life cycle management programs are as follows:

- Replacement of system components at end of component life before failure
- Replacement of obsolete parts; e.g., plant computer equipment
- Overhauls of pumps and valves
- Preventative maintenance on motors
- Inspections of heat exchanger tube bundle wall thickness
- Inspection and testing of electrical circuit breakers
- Calibration of instrumentation.

outage OM&A, and it's about outage OM&A that's outside of the DRP.

Is there a table in the evidence that summarizes outage OM&A by unit?

MS. CARMICHAEL: There is, I will provide it in a minute.

MS. BINETTE: For the test period?

MS. CARMICHAEL: Yes.

MS. BINETTE: Okay. I missed that so perhaps -- we are running out of time, so perhaps I can get that actual reference from you.

MS. CARMICHAEL: I believe it's CCC 24.

MS. BINETTE: Okay. And given that, at the bottom of this page, if you could scroll down to the last paragraph, it talks about some of the programs required under outage OM&A are required by the CNSC.

Would you be able to say how much of those numbers that you are providing in CCC 24 would be related to the requirements of the CNSC?

MS. CARMICHAEL: I don't believe we have that kind of Breakdown, because most of the work is required to run safe and reliable operations. Some of that was CNSC safety requirements, but they merge on, you know, types of work.

So I don't believe we have that kind of breakdown. But the work we are doing, and you have the categories there, is all about having safe, reliable operations during the refurbishment period for that unit, as well as the rest of the units; they are all interrelated.

So work needs to be done, CNSC work plus ensuring that work is done on the other components that aren't being done under DRP to ensure that maintenance is done, inspections, any repairs that need to be done, even on equipment that hasn't been able to access previously to get us to the end of the refurbishment window and come out with a unit that both from the DRP core scope perspective and the rest of the plant, the rest of the unit, they combine, come out both on improved performance based both on safety and reliability.

MS. BINETTE: I am going the leave that for now. Could we move to page 34, which is a corrected response and again it comes back to those warranty outages.

MS. CARMICHAEL: Could I have the IR please?

MS. BINETTE: Sorry, it's 6.1 Staff 97. And again about the warranty outages, it gives the cost of the first warranty outage at 12.8 million. And in the previous response, it was 10 million, and then it gives the second warranty outage cost at 8.2, and in the previous version of this response it was 3.7 million.

Can you explain the increase?

MS. CARMICHAEL: Yes, when we initially put the interrogatory response together, the station provided us with a response to what was in their budget. But outage costs are all sort of a -- they include station costs, but they also include costs from other organizations, and those were the costs we omitted in the original response to the IR.

	PICKERING EXTENDED OPERATIONS:							
	Nuclear - Direct							
16	Management	0.0	0.0	0.0	0.5	2.0	11.5	39.2
17	Society	0.0	0.0	5.0	19.7	46.0	94.9	374.7
18	PWU	0.0	0.0	25.0	56.2	59.0	80.3	717.7
19	EPSCA	0.0	0.0	0.0	0.0	0.0	0.0	6.8
20	Subtotal	0.0	0.0	30.0	76.4	107.0	186.8	1,138.5
	Nuclear - Allocated							
21	Management	0.0	0.0	0.0	0.0	1.0	1.5	12.0
22	Society	0.0	0.0	2.0	4.0	19.0	33.0	55.0
23	PWU	0.0	0.0	12.0	12.5	15.0	20.0	43.0
24	EPSCA	0.0	0.0	0.0	0.0	0.0	0.0	0.0
25	Subtotal	0.0	0.0	14.0	16.5	35.0	54.5	110.0
	NUCLEAR FACILITIES							
26	Management	0.0	0.0	0.0	0.5	3.0	13.0	51.2
27	Society	0.0	0.0	7.0	23.7	65.0	127.9	429.7
28	PWU	0.0	0.0	37.0	68.7	74.0	100.3	760.7
29	EPSCA	0.0	0.0	0.0	0.0	0.0	0.0	6.8
30	**Total Pickering Extended Operations**	**0.0**	**0.0**	**44.0**	**92.9**	**142.0**	**241.3**	**1,248.5**

1. Numbers may not add due to rounding

c) Some of the additional FTEs hired for sustaining Pickering operations will be term employees; however, the number of term employees to be employed has not been determined. Currently, term employees represent less than 1% of the nuclear organization headcount.

d) The decline of approximately 500 FTEs (about 8%) between 2017 and 2021 involves decreases in both regular and non-regular FTE as shown in Ex. F4-3-1, Attachment 1. This decline reflects reduced staffing levels associated with the completion of work programs to enable Pickering continued operations and a decline in outage activity in 2021. While a station-wide Pickering VBO is planned in 2021, non-refurbishment outage work at Darlington is restricted as two units undergo refurbishment. Also embedded in the business plan are staffing reductions for corporate support headcounts associated with achieving a 5% reduction from 2015 planned levels by 2020. Monitoring and control of new hiring as staff numbers fall due to attrition will continue, as well as initiative development and implementation to streamline processes and find new efficiencies to help manage attrition as OPG prepares for the end of Pickering unit operations beyond the IR test period.

Pickering Extended Operations. The outage OM&A costs for Pickering Extended Operations are set out in Chart 2 below.

Chart 1

Outage Frequency and Outage Costs 2013-2021

DESCRIPTION	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Darlington Unit Outages [1]	Unit 2; Unit 4	Unit 1	Unit 3 & Unbudgted Unit 1	Unit 4	Unit 1	Unit 3	Unit 4	Unit 1	None
Darlington Station Outages	VBO Preparation	VBO Preparation	Units 1-4 VBO Execution	None	None	None	None	None	None
Darlington Refurbishment Outages	None	None	None	Unit 2	Unit 2	Unit 2	Unit 2	Unit 2; Unit 3	Unit 3; Unit 1
Darlington PHT Pump Replacement Mini Outages				Unit 3	Unit 3; Unit 4	Unit 1; Unit 4	Unit 1	Unit 4	Unit 4
Darlington Post Refurbishment Outages	None	None	None	None	None	None	None	Unit 2	Unit 2
Pickering Unit Outages	Unit 1 (extended from 2012 [2]) Unit 5, 6	Unit 4,7,8	Unit 1, 5, 6 & Unbudgeted Unit 1, 8	Unit 4,7,8	Unit 1,5,6	Unit 4,7,8	Unit 1,5,6	Unit 4,7,8 [3]	Unit 1,5,6
Pickering Station Outages	None	None	None	None	None	None	None	VBO Preparation	Units 1-6 VBO
Pickering Mid-cycle Outages	Unit 4	None	None	Unit 1	Unit 4	Unit 1	Unit 4	Unit 1	None
Outage Costs ($Millions)	277.5	221.3	313.7	321.2	394.6	393.8	415.3	394.4	308.5

[1] Unit 2 will be subject to inspection and maintenance activities over the period 2017-2019 associated with a planned outage in accordance with OPG's aging and life cycle management programs, in addition to and separate from the refurbishment of the units.

[2] The Unit 1 outage was extended from 2012 into 2013 due to a fire in the Lube Oil Purifier system, resulting in the 2013 scheduled Unit 4 outage being shifted into 2014.

[3] The scope for the Unit 7 outage in 2020 is limited as it is solely for Pickering Extended Operations and therefore excludes "typical" planned outage.

Chart 2

Pickering Extended Operations Outage OM&A 2017-2020

Line No.	Cost Item	2017	2018	2019	2020	Total	Reference
		(a)	(b)	(c)	(d)	(e)	(f)
1	Pickering Station	12.2	11.6	20.8	22.8		Ex. F2-4-1 Table 1
2	Nuclear Support Divisions	9.9	25.7	67.9	62.8		Ex. F2-4-1 Table 1
3	Total Outage OM&A	22.1	37.3	88.7	85.6	233.7	

VECC Interrogatory #20

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

Interrogatory

Reference:
Reference: F2/T4/S1/Table 1

a) Please amend Table 1 to show outage OM&A by unit.

Response

a) See Chart 1.

Chart 1

Outage OM&A - Nuclear ($M)

Line No.	Nuclear Stations	2013 Actual (a)	2014 Actual (b)	2015 Actual (c)	2016 Budget (d)	2017 Plan (e)	2018 Plan (f)	2019 Plan (g)	2020 Plan (h)	2021 Plan (i)
1	**Darlington NGS**									
2	Unit 1	2.2	70.1	1.7	8.3	122.6	1.1	6.4	128.2	6.1
3	Unit 2	83.9	0.5	0.1	16.0	53.7	38.7	31.7	14.8	13.6
4	Unit 3	0.0	3.9	91.4	0.0	3.9	110.3	0.0	43.9	44.6
5	Unit 4	60.5	0.7	1.7	99.5	0.3	4.3	110.1	0.0	0.0
6	Common[1]	0.5	5.7	63.5	1.3	0.0	0.0	0.0	0.0	0.0
7	Total Darlington NGS	147.2	80.9	158.4	125.2	180.6	154.3	148.1	187.0	64.3
8	**Pickering NGS**									
9	Unit 1	4.2	2.9	47.1	2.4	61.7	2.3	51.6	1.2	53.9
10	Unit 4	14.6	42.4	5.7	47.1	2.8	53.9	8.4	63.4	0.0
11	Unit 5	44.4	6.1	44.2	6.3	61.9	14.5	100.6	2.2	66.6
12	Unit 6	59.4	1.6	45.8	0.8	71.1	2.2	86.7	6.1	62.7
13	Unit 7	1.3	49.9	1.7	68.4	1.7	85.5	0.8	43.6	0.6
14	Unit 8	3.8	31.4	2.0	58.5	6.3	68.7	9.1	85.0	14.1
15	Common[1]	2.5	6.0	8.8	12.5	8.5	12.2	10.0	6.0	46.2
16	Total Pickering NGS	130.3	140.3	155.3	196.0	214.0	239.4	267.2	207.5	244.2
17	**Total Outage OM&A**	277.5	221.3	313.7	321.2	394.6	393.8	415.3	394.4	308.5

Note:
1. Common outage costs include Vacuum Building Outages and repair of spare parts.

BASE OM&A – NUCLEAR OPERATIONS

1.0 PURPOSE

This evidence presents nuclear base OM&A expense for the historical period, bridge year, and test period (excluding OM&A expense for Darlington Refurbishment).

2.0 OVERVIEW

The nuclear base OM&A expense for 2013-2021 is provided in Ex. F2-2-1 Table 1. OPG is requesting approval of base OM&A expense of $1,210.6M in 2017, $1,226.0M in 2018, $1,248.4M in 2019, $1264.7M in 2020 and $1,276.3M in 2021. The average annual increase over the test period is 1.24 per cent.

The modest increases in the face of labour and material cost escalation reflect a continued focus on controlling staff levels, cost discipline and work reduction or elimination through re-prioritizing and streamlining work. OPG continues to implement various value for money, fleet wide and site initiatives to reduce costs as part of a focus on continuous improvement.

OPG's staff resource plan forecasts an increase in Nuclear regular staff FTEs (excluding Darlington Refurbishment) in 2016 to ensure resources are available following a period of higher than budgeted attrition. Thereafter, FTEs experience a net decline over the test period (Ex. F2-1-1 Table 3).

3.0 BASE OM&A BACKGROUND

Base OM&A provides the main source of funding for operating and maintaining the nuclear stations in support of:

- the ongoing production of electricity from the operating nuclear units;
- ensuring the safe operation of the plants;
- improving the reliability of the nuclear assets, and
- ensuring compliance with applicable legislation and nuclear regulatory requirements.

3.1 Base OM&A Description by Function and Resource Type

Board Staff Interrogatory #89

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

Interrogatory

Reference:
Ref: Exh F2-2-1 page 1 and Table 1

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

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

Response

Darlington's base OM&A in the test period is higher than 2015 actual, despite differences in the number of operational units, for two primary reasons.

First, the majority of base OM&A costs associated with operating a four unit station remains in place during refurbishment, as discussed at Ex. L-6.1-2 AMPCO-92.

Second, base OM&A increases over this period due to labour escalation reflecting collective agreement provisions.

AMPCO Interrogatory #92

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

Interrogatory

Reference:
Ref: D2-2-8 Attachment 4 Page 27

a) Please quantify the % of costs associated with the full time operation of Darlington that remains during the test period by year and show the calculation.

Response

Chart 1 compares the Darlington operating costs in the test period to 2015 actual operating costs. Darlington operating costs reflect amounts shown in L-6.2-15 SEC-63 part (b), Chart 1 for Stations and Nuclear Support for 2017-2021.

Chart 1

Line No.	($M)	2015	2017	2018	2019	2020	2021
		(a)	(b)	(c)	(d)	(e)	(f)
1	Total Darlington Operating Costs	694.6	723.4	686.0	681.4	725.4	588.5
2	Forecast Darlington Operating Costs as a % of 2015		104.1%	98.8%	98.1%	104.4%	84.7%

The majority of costs associated with the full-time operation of Darlington remain fixed as many of the functions that support the operation of all four units continue to be required during refurbishment to support the operation of a multi unit station even while units are on refurbishment outages. Examples of operating costs that remain even if one unit is in refurbishment include:

- Operating and maintaining safety systems and other common systems (i.e., Unit 0).
- Tritium removal facility that supports the remaining operating units, Pickering and other nuclear plants as well as other common facilities (e.g., water treatment plant).
- Fuel handling maintenance and operations to support fueling of the remaining operating units as well as fueling of the units undergoing refurbishment. Costs of defueling of the refurbishment units are included in DRP.

- Support, planning and contract oversight for work being performed within the station, except on the refurbishment units (the DRP will perform the oversight for the refurbishment unit).
- Operator training to ensure long term operability of the four units.
- Equipment inspections that are required on a periodic basis.
- Measurement, monitoring and reporting of environmental emissions.
- Security, nuclear programs, nuclear oversight, engineering and other nuclear support costs. Incremental security costs for the Refurbishment security entrance are funded by the DRP.

In addition, OPG has a comprehensive plan to perform non-refurbishment maintenance work on the unit that is offline. OPG cannot meaningfully allocate costs between the costs of such work and the other costs required to support the operation of the four-unit station. This work includes preventative and corrective maintenance work that would normally be done during scheduled outages but will be spread over the refurbishment period while a unit is on a refurbishment outage.

Note that total Darlington costs fluctuate year over year for a variety of reasons and in some years (e.g., 2017 and 2020), are higher than 2015 due to the outage program, additional inspection programs such as single fuel channel inspections, and specific life cycle management work. A description of year over year changes for base OM&A, project OM&A and outage OM&A costs can be found in Ex. F2-2-2, Ex. F2-3-2, and Ex. F2-4-2.

Board Staff Interrogatory #141

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

Interrogatory

Reference:
Ref: Exh A2-2-1 page 2 Attachment 1 page 15 Ref: Exh F2-1-1 Table 3

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

a) At page 2 of Exh A2-2-1, it states that the planning assumptions include Pickering 2022/2024. If so, why are there reductions in staffing levels in 2019-2021?

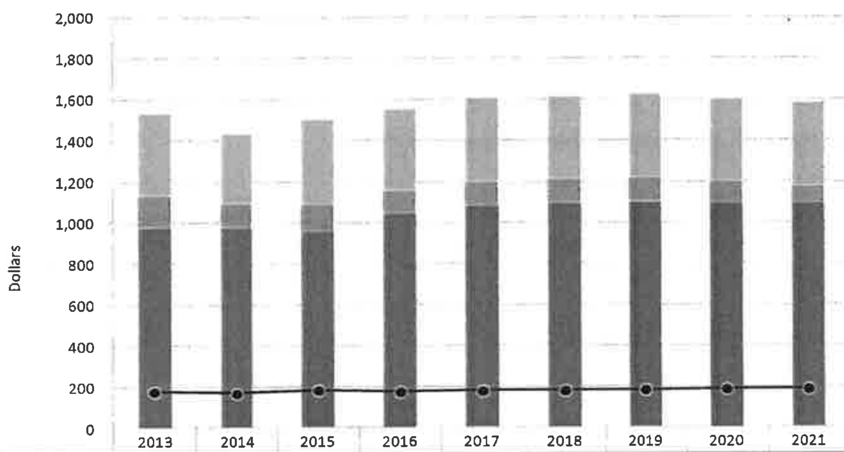
b) Does the business plan and the nuclear staff summary reflect the allocation of Darlington staff, from units undergoing refurbishment, to Pickering?

Response

a) OPG's staffing plans are based on the assumption that the Pickering station will operate until 2022/2024. However, the company's staffing strategy is to reduce headcount, where possible, in advance of the shut down. This applies to both direct and support organization and costs such as inspection, maintenance, engineering and corporate support services, which will start to ramp down staffing gradually in advance of the units closing.

b) There are no Darlington staff from units undergoing refurbishment allocated to Pickering in the 2016-2018 Business Plan or the nuclear staffing summary.

Figure 3 - Compensation Costs for Nuclear Facilities



	2013	2014	2015	2016	2017	2018	2019	2020	2021
Pensions & Benefits (M$)*	399	342	417	397	407	400	405	404	405
Overtime (M$)	159	118	132	112	117	116	119	102	81
Base Salaries & Incentives (M$)	976	978	956	1,046	1,082	1,095	1,099	1,097	1,096
Total Compensation (M$)	1,534	1,438	1,506	1,554	1,606	1,611	1,623	1,603	1,582
Growth Rate (Total Compensation)	6%	-6%	5%	3%	3%	0%	1%	-1%	-1%
Total Compensation (K$ / FTE)	179	171	186	178	182	184	187	190	191
Full Time Equivalents**	8594	8432	8114	8721	8801	8761	8665	8430	8293

*Pension and benefits include current service costs and are shown on an accrual basis.
** FTE includes both regular and non-regular FTEs. The actual 2013 FTEs shown are adjusted from those provided in EB-2013-0321, J7.3, Attachment 1. The adjustment increases the number of FTEs by excluding the impact of banked overtime (overtime taken as time off rather than pay) and shows the 2013 Actual FTEs on a consistent basis with the remaining years in the table.

Each component of compensation is described in more detail below, beginning with staffing levels. Additional details can also be found in Attachment 1 (FTE, Compensation and Benefit Information for OPG's Nuclear Facilities ["Appendix 2k"]).

FTE Staffing levels

In 2016, staffing levels for OPG's Nuclear facilities are expected to increase by over 600 FTEs due largely to the Darlington Refurbishment Project ("DRP") and, to a lesser extent, the workforce renewal required to sustain Pickering operations. In 2015, Nuclear attrition was at its highest level in years, with over 300 retirements.[4] This represents a 20 per cent increase in the number of retirements in Nuclear compared to 2014. Over two thirds of the 2015

[4] These retirements include only those reporting to the Nuclear organization directly. Attrition associated with support staff attributed to the prescribed nuclear facilities is not reflected in this number.

retirements were in critical operations, maintenance, engineering and technical roles and will need to be replaced. As shown in Figure 4, staffing levels peak in 2017 and then decline by over 500 FTEs by 2021. Nuclear staffing levels are discussed further in Ex. F2-1-1.

Figure 4- Nuclear Full Time Equivalents (FTE)

	2013*	2014	2015	2016	2017	2018	2019	2020	2021
Temporary	634	734	843	808	833	853	816	731	694
Regular	7,960	7,698	7,271	7,912	7,968	7,909	7,848	7,699	7,599
Total	8,594	8,432	8,114	8,721	8,801	8,761	8,665	8,430	8,293

* The actual 2013 FTEs shown are adjusted from those provided in EB-2013-0321, J7.3, Attachment 1. The adjustment increases the number of FTEs by excluding the impact of banked overtime (overtime taken as time off rather than pay) and shows the 2013 Actual FTEs on a consistent basis with the remaining years in the table.

Workforce renewal leading up to the end of commercial operations at Pickering in 2022/2024 will be required to continue operating the station safely. To assist in mitigating the anticipated disruption and costs associated with deployment and involuntary terminations after Pickering is shut down, a new category of employees called "Term Employees" was negotiated with the PWU for the current collective agreement period. In general, term employees may be hired to avoid adding regular staff in circumstances where additional regular employees are likely to be laid off as a result of Pickering's end of commercial operations. Term employees are hired with the understanding that they have no expectation of ongoing employment once Pickering's operations cease.

Base Salaries and Incentives represent about 68 per cent of OPG's total compensation costs related to the Nuclear facilities over the test period. These costs are largely a function

Board Staff Interrogatory #138

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

Interrogatory

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

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

Response

a) Between 2015 and 2016, the number of Regular Nuclear Operations FTE increases by 358 FTEs.

   As shown in Chart 1 below, an increase of 269 FTEs (75%) in 2016 is associated with filling critical positions largely due to 2015 attrition. The remaining 89 FTEs (25%) are civil maintainers, project technicians, inspection & maintenance technicians, security and emergency response. Of the 89 positions that are in other functions, 42 (12%) are associated with Capital Project Portfolio, 22 (6%) are associated with Provision work programs such as Used Fuel Storage and planning for Decommissioning, and 25 (7%) with on-going Nuclear Operations OM&A.

Chart 1

Increase in Nuclear Operations Regular FTE (2015 vs. 2016)	2015 Actual (a)	2016 Budget (b)	Difference (c) = (b) - (a)
Critical Job Families (Authorized, Engineers, Mechanical & Control Maintainers, Operations Specialists)	3,791.0	4,059.9	268.9
Other Functions (Maintainers Service, Technical, Other)	1,639.4	1,728.7	89.3
Total	**5,430.4**	**5,788.6**	**358.2**

b) Between 2015 and 2016, the number of FTE allocated to OPG's Nuclear facilities increases by 144 FTE.

As shown in Chart 2 below, an increase of 75 FTE (52%) is associated with critical positions supporting Nuclear Operations, such as Authorized Operations Trainers in the Learning and Development corporate function.

Chart 2

Increase in Allocated FTE (2015 vs 2016)	Nuclear Ops	Darlington Refurb	Nuclear Total
Critial Job Families (Authorized, Engineers, Mechanical & Control Maintainers, Operations Specialists)	66	8	75
Other Functions (Procurement, Warehousing, Information Management, Facilities & Business Infrastructure)	37	32	70
Total	**104**	**41**	**144**

Note: numbers may not add due to rounding.

Of the remaining 70 positions that are in functions, 32 (22%) are associated with the Darlington Refurbishment project, and 37 (26%) with on-going Nuclear Operations. These increases are to fill support roles primarily in OPG's supply chain, information technology and real estate services.

There are definitions in this interrogatory and interrogatory response that I am hoping you can help me with. Critical positions and critical job families? Can you give me those definitions, please.

MS. REES: Sure. So at OPG we group our jobs into what we call job families, and certain job families have a higher degree of operational impact or criticality. This would be positions like engineers, our operators, and some of our mechanical and control maintenance staff. So those are sort of broad groupings that we use, critical job families.

When we come to critical positions, that could be any position in any job family. It could be a leadership position, it could be a job that's not in the critical job family, but the role itself is very critical, so that's the distinction I would make between a critical job family and a critical position.

MS. BINETTE: So -- and this interrogatory talks about changes and hiring in groups in critical positions and critical job families.

Is there a higher bar for hiring in the other functions that are not critical or not in the critical job families? Is there more approval level required, or is it the same process?

MS. REES: Sorry, is there a higher approval for --

MS. BINETTE: Would you have to go through more levels of approval? Would you have to go to a higher level of approval to hire into positions that are not in the critical positions or critical job families?

MS. REES: No, not a higher level of approval.

MS. BINETTE: Okay, thank you.

MS. REES: You're welcome.

MS. BINETTE: Would you go to page 8, please. This is 6.6 Staff 152, and this is an interrogatory that queried positions that were not benchmarked by towers. And there are 282 Society positions in the general industry category that could not be benchmarked by towers.

And I was wondering if -- could you go to page 9, please. You may have to rotate that, but I am not sure it really matters. The general industry group has different job families. I was wondering if those 282 that could not be benchmarked could in fact be grouped by these job families, or not?

MS. REES: We haven't grouped them, but that could be done.

MS. BINETTE: Could I get that as an undertaking?

MR. SMITH: Yes.

MS. REES: Yes, sorry.

MR. MILLAR: JT 2.29.

UNDERTAKING NO. JT2.29: FOR THE 282 THAT COULD NOT BE BENCHMARKED, TO GROUP THEM BY JOB FAMILIES

MS. BINETTE: Could you go to page 10, please? This is 6.7, Staff 167, and it's interrogatory about corporate costs -- the corporate centre costs, excuse me.

Am I correct that there is a communications function under corporate centre?

NUCLEAR OPERATIONS AND TOTAL FTE

	Nuclear FTE	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
	Operations									
1	Regular	5,870.7	5,626.7	5,430.4	5,788.6	5,710.8	5,666.2	5,602.1	5,504.1	5,394.7
2	Non-Regular	496.9	578.1	670.0	666.7	614.4	646.6	632.2	526.8	420.4
3	**Sub-total Ops**	**6,367.6**	**6,204.8**	**6,100.4**	**6,455.3**	**6,325.2**	**6,312.8**	**6,234.3**	**6,030.9**	**5,815.1**
	DRP									
4	Regular	282.0	307.2	329.7	427.6	587.2	599.9	620.5	589.5	597.8
5	Non-Regular	24.6	35.3	60.7	73.5	153.2	152.2	137.4	157.7	230.1
6	**TOTAL Ops&DRP**	**6,674.2**	**6,547.3**	**6,490.8**	**6,956.4**	**7,065.6**	**7,064.9**	**6,992.2**	**6,778.1**	**6,643.0**
	Corporate									
7	Nuclear Allocated	1,919.5	1,884.4	1,628.9	1,773.3	1,742.8	1,703.7	1,679.8	1,659.0	1,656.2
8	**TOTAL Nuclear**	**8,593.7**	**8,431.7**	**8,119.7**	**8,729.7**	**8,808.4**	**8,768.6**	**8,672.0**	**8,437.1**	**8,299.2**

	Nuclear FTE	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
	Operations									
9	Base	5,217.4	5,158.8	5,042.6	5,121.8	4,968.7	4,956.2	4,970.6	4,910.1	4,826.3
10	Project	164.1	153.0	141.9	149.3	126.0	139.1	135.3	127.1	103.8
11	Outage	356.0	329.2	358.5	485.1	526.8	524.1	486.2	360.2	240.7
12	**TOTAL Ops**	**5,573.4**	**5,488.0**	**5,401.1**	**5,606.9**	**5,495.5**	**5,480.3**	**5,456.8**	**5,270.3**	**5,067.0**

1,2,3,4,5 - Exh F2-1-1 Table 3
6 - Exh F2-1-1 Table 3, Exh F4-3-1 Attachment 1
7,8 - Exh F4-3-1 Attachment 1
9- L-6.1-AMPCO-109
10 - L-6.1-AMPCO-111
11 - L-6.1-AMPCO-112

Chart 1

Base OM&A FTEs - Nuclear

Line No.	Regular FTEs	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Stations									
1	Darlington NGS	1,256.5	1,203.2	1,163.9	1,157.5	1,068.0	1,039.0	1,054.7	1,062.7	1,022.6
2	Pickering NGS	1,847.9	1,852.7	1,773.3	1,859.8	1,876.1	1,901.1	1,867.2	1,809.2	1,778.1
3	Pickering Continued Operations	20.1	14.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	Pickering Extended Operations	0.0	0.0	0.0	0.0	Not planned separately from PNGS				0.0
5	**Total Stations**	3,124.4	3,070.7	2,937.3	3,017.3	2,944.1	2,940.1	2,921.9	2,871.9	2,800.7
	Support									
6	Engineering	694.8	681.8	675.8	692.8	689.2	677.9	706.7	713.8	734.6
7	Projects & Modifications	73.0	64.3	63.5	58.8	56.0	53.2	53.2	50.1	46.2
8	Nuclear Services	225.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Fleet Operations and Maintenance	171.0	340.4	321.2	311.0	314.0	313.0	310.5	309.5	305.5
10	Security and Emergency Services	532.0	490.7	487.9	509.0	492.0	492.0	492.0	492.0	492.0
11	Inspection & Maintenance Services	202.0	191.7	177.1	222.2	217.0	197.2	212.8	206.1	196.4
12	Decommissioning & Nuclear Waste Mgmt	0.0	37.1	46.4	44.0	46.8	47.8	48.4	49.4	47.4
13	Other Support	23.0	6.8	10.1	40.6	63.8	53.0	56.6	59.2	51.4
14	**Total Support**	1,921.1	1,812.9	1,782.1	1,878.4	1,878.8	1,834.1	1,880.3	1,880.0	1,873.4
15	**Total Base OM&A**	5,045.6	4,883.6	4,719.4	4,895.7	4,823.0	4,774.2	4,802.2	4,751.9	4,674.1

Line No.	Non-Regular FTEs	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Stations									
1	Darlington NGS	65.2	110.9	128.0	107.0	56.4	85.8	85.8	75.8	75.8
2	Pickering NGS	45.0	73.7	85.3	77.4	35.5	35.5	35.5	34.6	34.6
3	Pickering Continued Operations	0.4	0.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	Pickering Extended Operations	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	**Total Stations**	110.6	185.3	213.2	184.3	91.9	121.3	121.3	110.4	110.4
	Support									
6	Engineering	18.2	39.6	58.5	20.0	20.0	20.0	20.0	20.0	20.0
7	Projects & Modifications	14.8	14.2	13.1	15.0	15.0	15.0	15.0	15.0	15.0
8	Nuclear Services	10.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Fleet Operations and Maintenance	2.3	15.7	19.7	2.0	2.1	2.1	2.1	2.1	2.1
10	Security and Emergency Services	2.1	3.5	2.7	0.0	0.0	0.0	0.0	0.0	0.0
11	Inspection & Maintenance Services	12.3	15.6	15.1	4.8	14.7	21.6	7.9	8.6	2.6
12	Decommissioning & Nuclear Waste Mgmt	0.0	0.8	0.5	0.0	2.0	2.0	2.0	2.0	2.0
13	Other Support	0.8	0.5	0.4	0.0	0.0	0.0	0.0	0.0	0.0
14	**Total Support**	61.2	89.9	110.0	41.8	53.8	60.7	47.0	47.7	41.7
15	**Total Base OM&A**	171.9	275.2	323.2	226.1	145.7	182.0	168.3	158.1	152.2

Total Base OM&A FTEs	5,217.4	5,158.8	5,042.6	5,121.8	4,968.7	4,956.2	4,970.6	4,910.1	4,826.3

Chart 1

Project OM&A FTEs - Nuclear

Line No.	Regular FTEs	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Portfolio Projects (Allocated)				FTEs not planned at detailed level					
1	**Darlington NGS**	13.1	11.4	18.2						
2	**Pickering NGS**	13.4	13.0	7.8						
3	**Nuclear Support Divisions**	33.6	22.4	12.7						
4	**Subtotal Portfolio Projects (Allocated)**	60.1	46.8	38.7						
5	**Infrastructure**	71.3	72.3	66.2						
6	**Portfolio Projects (Unallocated)**									
7	**Subtotal Project OM&A (Portfolio)**	131.4	119.0	105.0						
8	**Pickering Continued Operations**	4.1	4.3	2.0						
9	**Pickering Extended Operations**									
10	**Fuel Channel Life Cycle Mgmt Project**	5.4	4.3	0.0						
11	**Fuel Channel Life Extension Project**	0.0	0.0	3.0						
12	**Total Project OM&A**	141.0	127.6	110.0	107.8	104.5	115.6	112.8	104.6	81.3

Line No.	Non-Regular FTEs	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Portfolio Projects (Allocated)				FTEs not planned at detailed level					
1	**Darlington NGS**	1.0	2.5	7.2						
2	**Pickering NGS**	2.8	1.8	0.2						
3	**Nuclear Support Divisions**	8.2	5.6	5.5						
4	**Subtotal Portfolio Projects (Allocated)**	11.9	9.9	12.9						
5	**Infrastructure**	9.9	12.3	16.3						
6	**Portfolio Projects (Unallocated)**									
7	**Subtotal Project OM&A (Portfolio)**	21.8	22.2	29.2						
8	**Pickering Continued Operations**	0.9	1.0	0.4						
9	**Pickering Extended Operations**									
10	**Fuel Channel Life Cycle Mgmt Project**	0.4	2.2	0.0						
11	**Fuel Channel Life Extension Project**	0.0	0.0	2.3						
12	**Total Project OM&A**	23.1	25.3	31.9	41.5	21.5	23.5	22.5	22.5	22.5

Total Project OM&A FTEs	164.1	153.0	141.9	149.3	126.0	139.1	135.3	127.1	103.8

Outage OM&A FTEs - Nuclear

Line No.	Regular FTEs	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Nuclear Stations									
1	Darlington NGS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	Pickering NGS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Pickering Continued Operations	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	Pickering Extended Operations	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	**Total Stations**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	**Nuclear Support Divisions**	109.4	116.8	124.0	170.2	165.2	158.7	118.6	87.7	68.7
7	**Total Outage OM&A**	109.4	116.8	124.0	170.2	165.2	158.7	118.6	87.7	68.7

Line No.	Non-Regular FTEs	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Nuclear Stations									
1	Darlington NGS	106.7	61.2	79.2	90.4	113.0	112.7	112.4	110.5	6.7
2	Pickering NGS	44.6	70.5	49.8	56.2	103.9	103.9	103.9	43.0	95.0
3	Pickering Continued Operations	3.1	1.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	Pickering Extended Operations	0.0	0.0	0.0	0.0	Not planned separately from PNGS				0.0
5	**Total Stations**	154.4	133.2	129.0	146.6	216.9	216.7	216.3	153.5	101.7
6	**Nuclear Support Divisions**	92.2	79.3	105.6	168.2	144.6	148.8	151.3	119.0	70.3
7	**Total Outage OM&A**	246.6	212.4	234.6	314.8	361.5	365.4	367.6	272.5	172.0

Total Outage OM&A FTEs	356.0	329.2	358.5	485.1	526.8	524.1	486.2	360.2	240.7

1. **Labour:** The salary and benefits cost of OPG full-time regular staff, non-regular staff and part-time staff. Base OM&A labour costs are derived using standard labour rates for job families within Nuclear. In addition to base salary and statutory benefits (e.g. EI, CPP), these standard labour rates include a component for pension and other post employment benefits earned by employees for current service (discussed in Ex. F4-3-2) as well as a component for current employee health, dental and other benefits provided during employment.
2. **Overtime:** The incremental pay for work outside of core hours, for example during forced outages or urgent repairs.
3. **Augmented Staff:** External personnel providing specialized expertise (e.g., engineering) to supplement internal capability and/or to fill temporary vacancies.
4. **Other Purchased Services:** The costs of specialized external services, including construction and maintenance services, personal protective equipment, laundry services, and specialized technical services (e.g., nuclear safety analysis, research and development, and specialized testing services).
5. **Materials:** The costs of all consumables, replacement parts, and associated transportation service costs supporting station operations (e.g., ongoing maintenance and repair work).
6. **License Fees:** The cost of licensing-related fees paid to the Canadian Nuclear Safety Commission ("CNSC").
7. **Other Costs:** Costs for miscellaneous items such as travel and utility expenses (water, sewage, and electricity for administration buildings) and inventory obsolescence provision.

In order to operate the nuclear facilities safely, reliably and efficiently, OPG uses incremental short-term labour resources to address temporary staffing shortages. Incremental labour resources used by OPG include overtime, temporary staff (e.g., non-regular staff) and external contractors. Three primary factors drive the use of incremental short-term labour resources in Nuclear: 1) to meet peak work requirements, 2) to maintain coverage for key staff positions in accordance with licensing requirements, and 3) to complete priority work impacted by short term or unexpected staff shortages due to factors such as temporary

Introduction

- Willis Towers Watson has conducted a total compensation benchmarking study for roles across Ontario Power Generation's (OPG) Management, PWU and Society employee groups.
- This benchmark review has been conducted on a segmented basis. Roles are benchmarked against comparator organizations best representing the underlying skill sets required.
- The three segments are: Utility, Nuclear Authorized and General Industry.
- 78% of OPG incumbents are in roles covered by this benchmark review. In our experience, this is a strong representative sample.

OPG Group	Total # OPG Incumbents	Total # OPG Incumbents Benchmarked	% OPG Incumbents Benchmarked
PWU	**5,533**	**4,475**	**81%**
Utility	3,754	3,169	84%
Nuclear Authorized	255	255	100%
General Industry	1,524	1,051	69%
Society	**2,918**	**2,151**	**74%**
Utility	2,235	1,808	81%
Nuclear Authorized	111	53	48%
General Industry	572	290	51%
Management	**1,062**	**754**	**71%**
Utility	532	355	67%
Nuclear Authorized	39	37	95%
General Industry	491	362	74%
Total	**9,513**	**7,380**	**78%**

Note: OPG incumbent information as of April 2015

UNDERTAKING JT2.29

Undertaking

FOR THE 282 SOCIETY REPRESENTED POSITIONS THAT COULD NOT BE BENCHMARKED IN THE GENERAL INDUSTRY CATEGORY, TO GROUP THEM BY JOB FAMILIES

Response

Figure 1 below provides the 282 Society-represented positions in the General Industry segment that were not included in the Willis Towers Watson compensation benchmarking study (Reference: Ex. F4-3-1, Attachment 2). Suitable matches could not be found for these positions as discussed in Ex. L-6.6-1 Staff-152, part (a).

Figure 1

Job Family	Number of Positions
Administration	10
Corporate Services	44
Environment, Health & Safety	36
Finance	42
Human Resources	1
Information Technology	4
Maintenance	23
Operations	90
Supply Chain	32
Total	**282**

Board Staff Interrogatory #110

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

Interrogatory

Reference:
Ref: Exh F2-1-1 Attachment 2 page 13 and 28
Ref: EB-2010-0008 Undertaking J5.3
Ref: Exh F2-1-1 Attachment 4 page 12

Goodnight contacted CANDU operators globally and received no data to contribute to the study and was therefore unable to benchmark data for CANDU-specific activities. Through "technical adjustments" of PWR operator data, Goodnight determined that the appropriate CANDU benchmark was 5,208 FTE.

In response to undertaking J5.3 in the 2011-2012 payment amounts proceeding, OPG provided minimum complement data as set out in operating licences. Based on 5 shifts, the minimum complement for Darlington was 475 people and for Pickering was 630 people.

a) Are the minimum complement data based on headcount or FTE?

b) Have the minimum complement data changed since undertaking J5.3 was filed? If yes, what are they currently for Pickering and Darlington?

c) At Exh F2-1-1 Attachment 4 page 12, it states that the Days Based Maintenance initiative required CNSC approval as the minimum complement staffing number changed. What was the change in staffing number related to this initiative?

d) What are the CNSC minimum complement data for:
    i. An operational 4 unit Pickering facility
    ii. A non-operational Pickering facility
    iii. A Darlington facility with one unit under refurbishment
    iv. A Darlington facility with two units under refurbishment

Response

a) The minimum complement is based on headcount.

b) Yes, the minimum complement data has changed since undertaking J5.3 was filed in EB-2010-0008.

The Pickering minimum complement is currently 67 (previously 84) per shift with additional staff required during fuelling activities on a unit or if the heavy water upgrader is required to be operating.

The Darlington Minimum complement is currently 54 (previously 57) per shift when no fuel handling trolleys are being operated and 58 (previously 61) per shift when all three fuel handling trolleys are being operated.

c) The Days Based Maintenance initiative resulted in a net reduction of four minimum complement positions per shift at Darlington and 15 minimum complement positions per shift at Pickering. In addition, four of the minimum complement roles at each station were changed to only be required on 12 hour days (i.e., position is not required to be filled on night shift).

d) The CNSC does not prescribe minimum complement numbers. Rather, they are derived by the licensee based on the most resource-intensive conditions under all operating states, design basis accidents, and emergencies. The CNSC must accept any changes to minimum complement proposed by the licensee prior to implementation of those changes.

Related to the future reduction of operational units at Pickering, OPG expects to propose changes to the minimum shift complement as justified by changes to credible accidents, emergency situations, and operating states; however, the number of staff and related station conditions have not been determined at this time.

For Darlington, OPG has not proposed a reduction in minimum complement staff number for units under refurbishment as these staff are still required for monitoring and control of the units, although there has been a request accepted by the CNSC to reduce qualification requirements for operations staff monitoring the defueled unit in the control room.

UNDERTAKING JT2.18

Undertaking

TO PROVIDE THE PARALLEL NUMBER THAT'S PROVIDED IN J5.3.

Response

The parallel figures to those provided in EB-2010-0008 Undertaking J5.3 (lines 28-32) are:

- Approximately 525 people currently needed to cover the minimum complement at Pickering;
- Approximately 475 people currently needed to cover the minimum complement at Darlington.

Table 2
Base OM&A - Nuclear ($M)

Line No.	Resource Type	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan	Test Period Percentage[1]
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	**Labour[2]**	832.4	827.1	834.0	844.7	859.0	846.9	874.3	885.0	887.9	69.9%
2	**Overtime[2]**	48.6	46.7	54.5	47.8	46.1	46.5	46.1	47.4	47.8	3.8%
3	**Augmented Staff**	3.1	3.6	4.4	3.3	4.5	3.5	3.0	2.6	1.6	0.2%
4	**Materials**	85.1	73.4	83.4	70.5	68.4	68.2	68.5	71.1	70.8	5.6%
5	**License**	34.2	32.6	34.5	36.4	37.2	38.7	39.6	40.2	40.6	3.2%
6	**Other Purchased Services**	100.0	98.7	108.4	164.1	161.1	185.1	180.8	178.3	187.3	14.3%
7	**Other**	24.3	44.9	40.3	35.0	34.2	37.0	36.2	40.2	40.3	3.0%
8	**Total Base OM&A**	1,127.7	1,127.1	1,159.6	1,201.8	1,210.6	1,226.0	1,248.4	1,264.7	1,276.3	100.0%

Notes:
1 Test Period Percentage = Sum of Test Period Resource Costs divided by Sum of Test Period Base OM&A.
2 Includes Regular and Non-Regular staff.

AMPCO Interrogatory #114

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

Interrogatory

Reference:
Ref: F2-6-1

a) Please provide the forecast and actual purchases by vendor for the years 2013 to 2015.

b) Please provide the OM&A Purchased Services Nuclear Operations forecast for 2016 to 2021.

Response

a) OPG did not forecast purchases of OM&A services for nuclear operations by vendor for the period 2013-2015. Four vendors were identified in Chart 1 in Ex. F2-6-1, pp. 2-3 as having provided services in excess of a $17M threshold over the period 2013-2015. These vendors are AMEC-NSS, Black & McDonald Ltd., ES Fox Ltd. and Candu Owners Group. Aggregated amounts were provided in Ex. F2-6-1. Chart 1 below sets out the actual purchases over the period 2013-2015 by vendor. For confidentiality reasons, the vendors have been identified as A, B, C and D. Please note that the correct 2014 total amount is $129.4M as shown in Chart 1 below; the total amount for 2014 shown in Ex. F2-6-1, page 1, line 24 is incorrect.

Chart 1 ($M)

Line No.	Vendor	2013	2014	2015
	(a)	(b)	(c)	(d)
1	A	45.0	46.2	65.2
2	B	44.4	42.8	75.7
3	C	23.4	23.5	25.9
4	D	23.4	16.8	n/a
5	**Total**	**136.2**	**129.4**	**166.7**

b) Chart 2 below shows the Nuclear Operations OM&A Purchased Services forecast for each year from 2016-2021.

Chart 2 ($M)

Line No.		2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Total OM&A Purchased Service**	365.3	446.8	466.0	486.8	515.6	498.0

Numbers may not add due to rounding.

Table 2
Base OM&A - Nuclear ($M)

Line No.	Resource Type	2010 Actual	2011 Actual	2012 Actual	2013 Budget	2014 Plan	2015 Plan	Test Period Percentage[1]
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**Labour[2]**	890.0	954.3	807.7	848.6	836.7	836.7	72.6%
2	**Overtime[2]**	52.0	54.5	48.5	30.2	31.9	32.8	2.8%
3	**Augmented Staff**	6.9	3.0	2.6	0.3	0.4	0.5	0.0%
4	**Materials**	70.7	76.2	91.1	71.2	71.8	68.9	6.1%
5	**License**	26.0	29.0	30.1	32.7	34.7	35.2	3.0%
6	**Other Purchased Services**	97.0	94.8	95.4	126.7	145.9	146.4	12.7%
7	**Other**	38.7	37.2	27.1	29.8	29.7	33.3	2.7%
8	**Total Base OM&A**	1,181.4	1,249.1	1,102.6	1,139.6	1,151.1	1,154.0	100.0%

Notes:

1 Test Period Percentage = Sum of Test Period Resource Costs divided by Sum of Test Period Base OM&A.

2 Includes Regular and Non-Regular staff.

-- I can provide you why, on a refurbishment unit, there is a requirement for operation staff. So even though, you know, we have removed fuel from the reactor and it is no longer a nuclear reactor, what that does is it mitigates the requirement to have authorized licensed operators sitting in front of a control room panel. It does not eliminate the requirement to have operation staff available, because any equipment that gets operated in the power plant -- and a significant amount of equipment even in the refurbishment does need to get operated. There are systems that we're not touching.

And then there are -- as we work through the scopes of work, there are activities that are required in order to safe-state equipment, to do testing and bring things back in-service. That's all operations work. So there's quite a significant impact on operations to support refurbishment.

We also have -- it is a power plant that has equipment that needs to be maintained, and the last thing that we want to do in this -- if we took our eyes off the maintenance that needs to be done to equipment that isn't being taken apart or replaced in refurbishment, we'd essentially run the risk that Bruce Power encountered, where you're starting up a plant; equipment wasn't looked after properly; and then it takes a very long time to correct all of those things as components start to fail when you return the plant in-service. So there is a full maintenance program that gets executed on the refurbishment unit while it is in the refurbishment state.

MR. STEPHENSON: Thank you. Those are my questions. Thank you, Board, for that indulgence.

MS. LONG: Thank you, Mr. Stephenson.

MR. POCH: Madam Chair, just before you break, I know I'm next up after Mr. Tolmie, and I just -- I was going to slip out now, but if it's helpful to the Board, I can stay around if you think you might want to fill the last few minutes. I know you've had some late evenings. You probably don't want to, but --

MS. LONG: I wasn't sure that you were going today, Mr. Poch.

MR. POCH: No. I'm scheduled first up the next day.

MS. LONG: Oh, are you? Okay.

MR. POCH: But I'm available. That's all -- I was just making that offer if it was --

MS. LONG: Okay. Okay.

MR. POCH: -- convenient, but I'm happy to leave, frankly.

[Laughter.]

MS. LONG: I think that we will end today, actually, with Mr. Tolmie. Okay. Thank you.

So, Mr. Tolmie, you're next up after our 15-minute break. Thank you.

--- Recess taken at 3:39 p.m.

--- On resuming at 4:07 p.m.

MS. LONG: Mr. Tolmie?

MR. TOLMIE: Could we have the compendium on the is safely isolated and de-energized. Is that right?

MR. REINER: Yes, that's correct. Work protection essentially provides that safe -- that safety zone that allows for the work to be executed -- to be executed safely without being exposed to hazards.

MR. RICHLER: And OPG staff are responsible for providing isolation and de-energization. Is that right?

MR. REINER: In the Darlington refurbishment, there is actually a model where OPG and contractors utilize work protection, so OPG most definitely for all of the interface points to the refurbishment work, so any piping that might have steam in it or some high energy associated with it, pressurized air, that sort of thing, or electrical isolations that are required, there would be an OPG work protection that's applied to provide that boundary.

Within that boundary for specific items of work that gets executed, the contractors also have, as part of their quality programs, a work protection program that they utilize to then provide a safe boundary within their environments, because they do have a requirement to apply temporary power and energy to systems as they do work, and they would do that under their own work protection.

MR. RICHLER: To the extent the work protection is performed by OPG as opposed to a contractor, is that work done by DRP staff or unit 2 operations staff?

MR. REINER: So that is operations and maintenance staff that are costed into the DRP, so that work is part of the $12.8 billion. The actual staff doing that work would recruiting process. I mean, hiring somebody, going through interviews, and that takes time. We wanted our managers focused on the work, so we facilitated and helped them through the hiring, and we hired about 200 people between August and the end of the year on the project.

MR. RUBENSTEIN: All right. So if you had hired 691 at the actual in August, then you add 200, it still seems to me you are below where you would -- where you needed to be by a good amount?

MR. REINER: So below where this -- where this curve was generated, but what I will tell you is we are not below where we need to be. We have access to resources to manage the project. If we can't get them as full-time regular OPG staff, we're able to hire contractors, and we're also able to -- if we were to find ourselves in a critical need of a resource, we're also able to move people around in our nuclear fleet and assign people to the project.

Now, the staffing plan is a living plan, so this is not "Here's a forecast, and we're going to exactly match the forecast." At the time the forecast was built, there were assumptions that needed to be made about what level of effort is needed on behalf of OPG to manage the work.

As we get into execution and as that changes, we adjust the resources. And there are -- as Mr. Rose said, there are some areas where we are still currently hiring people, and we are bringing people on staff, but we're not at a place where we have a significant shortfall that introduces a complication for us in terms of managing the is safely isolated and de-energized. Is that right?

MR. REINER: Yes, that's correct. Work protection essentially provides that safe -- that safety zone that allows for the work to be executed -- to be executed safely without being exposed to hazards.

MR. RICHLER: And OPG staff are responsible for providing isolation and de-energization. Is that right?

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MR. REINER: So that is operations and maintenance staff that are costed into the DRP, so that work is part of the $12.8 billion. The actual staff doing that work would be potentially operations staff.

MR. RICHLER: Are most of the work protection efforts front-loaded in the early months of the unit 2 refurbishment, or is this something that is happening at a fairly even pace throughout the entire 40-month high-confidence schedule?

MR. REINER: It happens throughout the entire schedule and really aligns with, if you were to look at the schedule, aligns with the work that gets executed in the schedule. And then there is quite a significant effort -- and it's not obvious from the schedule itself. There is quite a significant effort at the back end as systems are returned back to service and energy is reapplied to the power plant. So it is a -- fairly continuous with quite a heavy emphasis on the back end.

MR. RICHLER: I would like to understand better when OPG would consider the unit 2 refurbishment to be complete. Is it the day the unit is reconnected to the grid?

MR. REINER: There is a -- in the schedule, there are -- so there are a series of tests that occur as power is raised on the unit, and that is still done within the refurbishment period. So we call it complete when the unit is connected to the grid and operating at high power. We don't define precisely what high power means, because there could be -- there could be things happening operationally that could adjust that. But it would be at high power and producing electricity and connected to the grid.

MR. ROSE: There's two parts to this. There is one

-- I can provide you why, on a refurbishment unit, there is a requirement for operation staff. So even though, you know, we have removed fuel from the reactor and it is no longer a nuclear reactor, what that does is it mitigates the requirement to have authorized licensed operators sitting in front of a control room panel. It does not eliminate the requirement to have operation staff available, because any equipment that gets operated in the power plant -- and a significant amount of equipment even in the refurbishment does need to get operated. There are systems that we're not touching.

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Project #34000 Darlington Auxiliary Heating System:

The auxiliary heating system ("AHS") project involves the replacement of the life expired original station construction era boiler house at the Darlington site. Auxiliary heating is required as backup in order to protect station systems in the event that there is a power outage and loss of electricity and heating in the power plant on cold days. The project was undertaken to address a long standing CNSC concern regarding the adequacy and reliability of the backup heating available in the event of a four unit outage during the winter. The new AHS facility would provide a source of reliable back-up steam to the Darlington Nuclear Generating Station main heating steam in the event of a four unit shutdown, thereby mitigating potential major equipment damage due to freezing. The AHS project was reclassified to the Nuclear Operations Project Portfolio in 2015, as discussed in Ex. D2-1-10.

During EB-2013-0321, OPG updated the forecasted total project cost of the AHS project to $85.1M as set out in an execution release BCS. OPG also provided a forecast in-service amount of $75.3M in 2015.

The expected final forecast project completion cost, including the demolition of the construction boilerhouse slated for October 2016, has increased by $14.4M to $99.5M, as set out in the full release BCS included in Attachment 1, Tab 11 to this exhibit. This increase is for additional funding to complete the construction of the AHS and commissioning, demolition of the construction boilerhouse and close out. The in-service amount is $94.2M in 2016. The increase is a result of several factors with the most significant being higher than anticipated engineering-procurement-construction contract costs resulting from the following:

- Approved project change authorizations due to design and construction scope changes (+$3.9M)
- Under-estimation of vendor engineering, construction and commissioning support (+$5.8M)
- Under-estimated fabrication and installation sub-contractor costs (+$4.3M)
- Increased labour costs, e.g., lengthened schedule for completion (+$2.7M)
- Increased internal project management and support costs ($1.7M)
- Increased material costs (+$1.0M)

- Increased interest due to the longer construction schedule (+$0.3M)

These cost increases were offset by reduced project contingency (-$5.3M).

Project #25619 Darlington Operations Support Building Refurbishment: The operations support building ("OSB") (also reclassified from the DRP per Ex. D2-1-10) houses various technical services (e.g., site security, site information technology, telephone network hubs) essential to the business operations of Darlington pre- and post-refurbishment. The OSB was constructed in 1982, with a third floor added in 1988. An assessment by an external engineering firm found that many of the existing building systems are or would life expire by 2015 and concluded that the preferred alternative was refurbishment of the building.

During EB-2013-0321, OPG provided an updated forecast in-service amount of $45.1M in 2015. This was based on a forecast total project cost of the OSB refurbishment project of $47.7M (including contingency) as set out in the partial release BCS included in Attachment 1, Tab 1 to this exhibit.

The forecast project completion cost of the OSB is now $62.7M, which consists of a full release for execution of $53.0M with a superceding release for an additional $9.7M. This increase is primarily due to increased engineering, procurement and construction ("EPC") contract costs (+$8.8M) arising from under-estimation of effort to complete contract scope, including scope additions for electrical distribution equipment upgrades, additional telephone and information technology cable and hardware, upgrades to fire separation barriers and other minor changes.

In-service amounts are $55.1M in 2015 and $3.6M 2016.

Project #25609, Security Physical Barrier System: A supplemental release of $67.2M for an additional $17.7M over the full release of $49.5M was primarily due to:

- Settlement of a claim by a subcontractor to the EPC vendor (+$7.0M)
- Higher costs to complete portions of the project (+$1.1M)

Type 3 Business Case Summary

Document #: D-BCS-00120.3-10021

Project #: 16-34000
Project Title: Darlington Auxiliary Heating System Project

Project Overview

History of BCS releases and project cost estimates:

Definition Developmental Phase ($437ktotal: $427k base cost + $10k contingency) was released in November 2010 to fund completion of a Gap Analysis Report of the preferred alternative, revise Design Requirements and complete a Black Start Option Benefit Cost Analysis and Economic Risk Assessment. A previous developmental phase release had been approved for the project in 2006 but the project was deferred in 2008 to allow for completion of the Design Basis. Of the 2006 release, $904k was spent.

Definition Developmental Phase ($1,245k total: $1,094 base cost + $151 k contingency) was released in October 2011 to fund the completion of the preliminary site investigation, and Request For Proposal (RFP) process for the Engineer, Procure, Construct (EPC) Contract.

Full Definition Phase ($4,850k total: $3,980k base cost + $870k contingency) was released September 2012 to complete modification planning and initiate engineering of the new AHS.

Partial Definition Phase ($33,432k total: $27,349k base cost + $6,083k contingency) was released in November 2012 to fund the detailed engineering, major component procurement and construction of the new AHS Boilerhouse.

Partial Definition Phase ($42,407k total: $36,611k base cost + $5,796k contingency) to fund completion of Engineering; Materials Procurement; Facility and Tie-ins Construction, Commissioning, AFS and EC Close-out of the new AHS; EPC Contract Award for Demolition of existing CBH, and Modification Planning and Detailed Design for Demolition of CBH.

Full Execution Phase – This BCS ($17,126k total: $16,626k base cost + $500K contingency) to fund completion of Facility and Tie-ins Construction, Commissioning, AFS and EC Close-out of the new AHS; and Complete demolition of the Construction Boilerhouse (CBH).

History of scope and schedule changes:

The total project cost has increased from $85,102k to $99,497k as a result of:

- Additional OPG Costs to support the extended Project duration from March to October for Available for Service of the New AHS.
- Additional support from Project Control Center to provide an interface with the Station to support tie-in work,
- Additional Contract for a Boiler Subject Matter Expert to augment the Project Team.
- Underestimation of the OPG Radiation Protection support required for the In-Station installations of Steam, Condensate and High Pressure Demineralised Water.
- Engineering costs have also increased substantially due to:
  - Underestimation in design complexity,
  - Late receipt of Vender Information to support design,
  - Underestimation of the Contractual obligations per the Contractor Owner Interface Requirements,
  - Addition of a Chemical Storage Annex due to an undersized building footprint,
  - The large number of Requests For Information between Constructor and their Design Agency.
- Engineering and Construction costs for the Steam and Condensate lines to go through the Security Fence instead of under the Security Fence to minimize risk of buried services encountered utilizing directional boring technology,
- Underestimation of dewatering costs,
- Underestimation of material and construction costs. Several major material items, including boilers and auxiliary equipment, required custom design to accommodate the limited space of the building footprint, which was not part of the original bid by the Contractor.
- Procurement and Construction proceeding based on a staged release of Engineering packages. This led to inefficiencies in material procurement and construction activities.

The overall Project schedule has been impacted as a result of the challenges identified above. The Engineering completion milestone in the previous BCS of August 11, 2014 has been changed to June 12, 2015.

The new AHSF Available for Service is scheduled for October 31, 2015.

- Mischaracterized the nature of these estimates by assuming anything provided by a contractor was at a very high level of maturity (Class 3/2) when such estimates were based on conceptual (at best) engineering, meaning these estimates could not have been better than Class 5 (-50% to +100%) in nature;
- Failed to establish accountability standards for the contractors;
- Failed to identify or mitigate known risks;
- Did not effectively react to problems when they materialized and accurately and timely report the extent of cost overruns, schedule delays and scope increases to senior management;
- The P&M Team did not seek to lock down the scope at start of this work and allowed the "customer" – Operations and Maintenance – to make significant changes to the design that were not properly understood, quantified or captured in subsequent reports to senior management; and
- The ESMSA contractors contributed to the problem by not transparently reporting or timely identifying how these projects were evolving and failing to provide any reliable metrics—cost, schedule or otherwise – that informed OPG of these brewing problems.

2. Indicative Projects - D2O Storage and Auxiliary Heat

In our analysis, BMcD/Modus examined five separate projects in detail, and each exhibited some or all of the management issues to some extent. Attachment C is a brief summary of each of these projects' cost overruns.

The management failures we observed were most evident and acute with the D2O Storage and AHS projects. These projects were the "pilot" EPC projects for the ESMSA contractors—[redacted] In both cases, P&M sought the Board's full funding approval at a point when very little design was done, only to have to later seek additional funds from the Board once design had matured.

a. The Flawed Bidding/Estimating Process

P&M's management failures can be seen throughout the planning and execution phase of the project. Notable from OPG's initial negotiation and acceptance of bids for this work is P&M's mischaracterization of the vendors' estimates in the approved Business Case Summaries ("BCS"). In August 2011, OPG produced a BCS for D2O Storage that estimated its cost at $210.6M, [redacted]. At the project's next gate in June 2012, the estimated cost had dropped from $210M to $108M. However, BMcD/Modus could not find any attempt by P&M to rationalize or otherwise explain how the cost estimate for this building was cut virtually in half from one approval gate to the next. Moreover, the estimate for design and construction was $52.2M, which P&M characterized as a "Class 2 Estimate" despite the fact that at the time of the estimate, Black & McDonald had little experience with this type of construction and had performed no engineering or scope definition. Thus, this estimate was more likely a Class 5 Estimate. In retrospect, it is likely that the initial $210M estimate was more accurate; however, it is certainly clear that the approved $108M estimate should not have had any greater accuracy attributed to it, since it was not based on a significantly greater level of project maturity. Likewise, the AHS BCS was termed a "Class 3" Estimate, though it was similarly immature.

This estimate classification drove P&M to vastly underestimate the amount of contingency associated with each package. There is no evidence that P&M engaged in the type of vetting of the estimates that we would expect on projects of these size and importance. From interviews with the current P&M staff and the contractors, it appears that these initial BCS estimates were poorly characterized as part of a deliberate management strategy directed by the former VP of P&M. P&M's managers told us that the contractors were challenged to reduce their bid prices and remove all contingencies for unknowns, despite the extreme immaturity of project definition underlying their respective bids. As an example, for the D20 Storage project, Black & McDonald was told to remove from its contract price any contingency for unforeseen soil conditions, even though there was a high likelihood that there would be contaminated soil issues. Moreover, P&M clearly overvalued price as a consideration in the contractor selection process, especially in light of the fact that the work was going to be performed on a cost-reimbursable basis and the bid prices were not binding.

P&M gave only token consideration to determining which contractor had a better approach for executing the work. P&M chose the "low bidder" even though the other contractor's qualifications and project approach were viewed more favorably. Thus, P&M created the conditions for a perfect storm of cost and schedule overruns. Because the work is largely based on a cost-reimbursable target price with no caps on size, P&M's artificial beating down the contractors' prices in the bid phase was a Pyrrhic victory: P&M's actions did not reduce cost and only served to deprive senior management of realistic cost projections for this work. The budgets for these and other F&I projects were nothing more than paper barriers that were easily surmounted as the design work continued to generate more complex (and expensive) work.

b. Lack of an Integrated Schedule

Until April 2014, the P&M project teams for D20 and AHS were working without a reliable, integrated Level 3 Schedule. Many on the project and throughout the OPG organization were given a false impression that the Campus Plan Projects, and D20 in particular, had a year of float, and so on-going delays had no impact on the Project. The delays to D2O Storage's schedule were not forecasted by the project team and were simply reported after the fact. By this point, the schedule had already slipped so that engineering was on its way to an 18-month projected overrun of an original 11-month schedule. However, without a resource-loaded, level 3 schedule, it was impossible to assess the status of the project, let alone calculate with any accuracy any remaining float.

One of the strategic initiatives was implemented by the new P&M VP was to improve the projects' schedules. This endeavor allowed the project team to see that D20 Storage was actually projected to be completed on April 26, 2016, more than a year after the original April 15, 2015 deadline. Furthermore, once known risks are factored in, it is likely that the D20 project can only achieve this revised date if some of the schedule durations are accelerated—at an additional cost. Even then, these efforts will not improve completion of the schedule by much, but will increase the probability that the April 2016 date can be met. However, none of this would be known if efforts had not been made to improve the schedule.

c. Risk Management

Based on our observations, it appears that all P&M's identification of risks is a "check-the-box" activity due the fact that having a list of risks is a prerequisite to obtaining a funding release. P&M does not actively manage its on-going risks as a part of an effective risk management program. As an example, the risk sections of the D20 and AHS BCSs consist of lists of potential risks and some evaluation of their nature, but it is not apparent that these risks in any way influenced the calculation of these projects' contingency, nor are there any regular reviews or updates of these risks until required to do so in order to pass a gate and obtain a funding release. Once a project obtains full funding for execution, very little, if any, attention is paid to day-to-day risk management, including the ongoing identification of new risks and opportunities as well as the formalized implementation of risk mitigation strategies. Additionally, there is no structured or defined risk program management oversight (such as the NR Risk Oversight Committee).

A recent self-assessment performed by the NR Management Systems Oversight group (SA RF13-000855 dated January 20, 2014) identified perceptions (opinions) of several P&M managers that included the following: "[D]evelopment and use of a Risk Register is seen as purely administrative and not adding value to the Project Managers." This suggests a lack of understanding of the value of a risk management program or lack of acceptance, which can be addressed by effective training and indoctrination. However, risk management training is virtually non-existent in the P&M organization in distinct contrast to several years ago when quarterly workshops were regularly conducted.

d. The Gate Process and Failure to Report Cost and Schedule Increases to Senior Management

BMcD/Modus next explored the relative effectiveness of the gate process for this work, and found that while the process in concept is a good one, it suffers from problems in execution. The BCS documents for D2O Storage and AHS were inconsistent in presentation of key information on cost, risk and scope. As these projects progressed, P&M's management failed to provide visibility to OPG management of the extent or nature of project cost increases. Most notably, P&M failed to update its project reports during the design phase to reflect cost increases due to scope changes in the projects.

AHS provides a critical example. On November 12, 2012, P&M presented its Gate 3A package for approval and full funding release (except for a small portion of costs to be approved in 2014). The P&M Team's gate presentation characterized the AHS cost estimate as a Class 3 estimate in the amount of $45.6 M. P&M included [redacted] of contingency in the $45.6M estimate, of which [redacted] was identified as having a 100% chance of occurrence. P&M expressed an "85% confidence level" in this cost estimate and assessed there were [redacted] days of schedule contingency in the estimate—despite the fact that the full scope of the project was not known at that time because detailed engineering had not started. The option of building a new AHS was preferred over seven alternatives, based primarily on the projected cost. At the time of this gate, the project had spent $1.46M.

Between this gate and January 2014, ES Fox engaged in the design of the AHS, scope changes caused the cost to increase from the initial $45.6M estimate to $79.9M. This cost increase is largely attributable to two causes: (1) remediation of contaminated soil that as of the time of bid was known by both OPG and the contractor to be of poor quality; and, (2) prescriptive design requirements that served to make a stock steam boiler design follow nuclear Engineering Change Control ("ECC") processes, which caused an increase in the size, complexity and nature of the work. Moreover, these design requirements and the overall length of the design phase, coupled with the soil issues, has frittered away virtually every day of float.

The fact this project had so substantially changed from the original BCS was not accurately or timely reported to management. The failure of the gate process was that the Gate Review Board members did not provide adequate oversight in ensuring that the AHS project team had a reliable estimate, schedule, and well-defined scope prior to approving the gate and recommending a funding release. As of January 2014, P&M had already expended nearly $20M, or more than half the approved budget excluding contingency, even though the design was not complete and no construction had begun. However, during this entire time, P&M's estimate at completion ("EAC") in all of the DR Project's and Campus Plan reports ***never varied*** from the approved BCS amount. Moreover, the DR Project's Program Status Report for March 2014 showed the AHS at 49% spent with a CPI of 1.10 and an SPI of 1.0, clearly not an accurate representation of the Project's status. Part of this failure was based upon some of the P&M project managers' mistaken belief that the reported EAC amounts should not be changed until additional funds had been approved for the projects. This lack of accurate reporting has deprived senior management and the Board the option of revisiting the original BCS analysis in order to determine if building a new AHS facility continues to be the preferred option—and if not, change course. This is particularly true in light of the fact that as of November 2012, three of the competing options to building AHS were priced at less than $50 M.

D2O Storage provides a very similar example at a much higher overall cost. The cost variance progression from D2O Storage began with an original approved BCS of $110M, based upon estimated contractor costs of approximately $77.8 Million. The ES Fox team and design solution were both preferred but Black & McDonald was chosen entirely because its price was $30M less even before P&M further drove Black & McDonald's estimate down.

D2O Storage's engineering effort was originally scheduled for 11 months, and was supposed to be completed by July 2013. However, even today, engineering is not complete and is projecting to extend to a total duration of 29 months. The P&M team provided sporadic updates to the design milestones as they continued to be missed but failed to convey the potential consequence. In August 2013, P&M reported that CNO Milestone 73472M0015, "D2O Modifications –

Detailed Design Complete" was expected to miss its planned completion date of August 21, 2013 **by four months** though stated, "there is no impact to the critical path."[4] As of this same meeting, an action was recorded to "confirm the timing for integration" of the D2O Storage schedule into the master C&C Schedule, the follow-up to which indicated that the schedule would not be available for integration because "it falls short of our requirements for several parameters."

In September 2013, P&M reported in the Program Status Report that:

> Due to the change in design for the connection of the new tanks to the existing, significant additional design work is required. This change of design was required to address water hammer issues with the initial plans which could not be resolved without a significant change in design. A new underground tunnel connecting the two buildings will now be utilized to connect the two buildings.[5]

However, this "significant" design change was not highlighted as a major risk item in P&M's reporting, and P&M maintained the same EAC for D2O Storage despite having this information in hand. P&M also maintained that there was no impact to the critical path, even though P&M again admitted that the vendor had yet to produce a detailed schedule, which begs the question how could one arrive at such a conclusion regarding float without a reliable schedule.

P&M first reported a variance to the D2O Storage budget in October 2013, which coincided with months of mitigating adverse soil conditions and failing to meet the schedule for tie-ins for the TRF outage. Black & McDonald presented a high-level cost estimate that showed approximately $49M of increases in foundation work and engineering in October 2013, though this estimate was characterized as a work in progress. This estimate was increased by $5M in December 2013. P&M finally updated the D2O Storage EAC in the January 2014 DR Program Status Report from $95M to $122.7M, though simultaneously, P&M issued a report to the Nuclear Executive Committee ("NEC") showing a forecasted EAC of $152M. Thus, P&M's first reporting to senior management and other OPG stakeholders of any impact of the design changes that had been brewing for nearly two years was inconsistent at best.

In January 2014, Bill Robinson required Black & McDonald to update its costs. Black & McDonald committed to an estimate of $94M (compared to its original contract of $67M), which with OPG's costs was ranged by P&M at a total of $150-170M, including OPG contingency and financing costs. After coming on board, P&M's new VP required Black & McDonald to prepare a bottoms-up, high confidence schedule and budget based on the high level of engineering completion. Black & McDonald's output has trickled in. [redacted] Black & McDonald has broken down the cost increases into several categories, including: additional scope ($85.4M), changed assumptions ($14M), soil remediation ($17.3 M), delays to the schedule resulting in acceleration ($9.8 M) and inclusion of items that were either missed or misestimated in the original estimate ($31 M). Black & McDonald characterized this estimate as a Class 4 even though: (1) the design is 80% complete; and (2) Black & McDonald had just provided a Level 3 schedule for the remaining work which they claimed was comprehensive. Based on these two data points alone, Black & McDonald should be able to produce at least a Class 2 estimate at this time. [redacted].

Moreover, throughout 2011-13, P&M did not require Black & McDonald to timely update costs and provide visibility to the cost of these design changes as they were occurring; thus, as with AHS, P&M's management allowed the contractors

[4] DN Refurbishment Program Status Report Meeting, August 21, 2013
[5] DN Refurbishment Program Status Report Meeting, September 18, 2013

to run up the tab and incorporate a flood of OPG stakeholder generated late design changes without adequate checks and balances or understanding of the magnitude of these changes.

As a direct consequence of P&M's failure to report these cost and schedule variances, senior management was deprived of the ability to:

- Stop the design changes that led to these increases;
- Stop the project entirely and resort to one of the other evaluated options;
- Identify and characterize the cost increases that are not related to Refurbishment and subject these changes to the same value-enhancing criteria as the remainder of the DR Project's work; and
- Mitigate the impact of the schedule delays and overruns.

Thus, the consequences to OPG are two projects that may cause external stakeholders to question OPG's management prudence.

e. Vendor Performance Issues

[redacted]

[redacted]

[redacted].

[redacted]

[redacted]

Board Staff Interrogatory #71

Issue Number: 4.3
Issue: Are the proposed nuclear capital expenditures and/or financial commitments for the Darlington Refurbishment Program reasonable?

Interrogatory

Reference:
Ref: Exh D2-2-10, Chart 1

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

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

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

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

c) Please explain further the rationale for reclassifying these projects from the DRP to the Nuclear Operations portfolio. Does OPG anticipate reclassifying any further projects?

Response

a) OPG confirms that the table shows all capital projects that have been reclassified as Nuclear Operations portfolio capital projects, as noted in Ex. D2-2-10, pp. 10-11. With the exception of the Highway 401 & Holt Road Interchange, the total project cost for all other projects listed in the table is correct. As stated in Line 32 of Table 1 in Ex. D2-1-3, the total project cost for the Highway 401 & Holt Road Interchange is $28.6M.

b) The main purpose of the Release Quality Estimate (RQE) was to prepare a high confidence cost and schedule estimate based on the final scope to be managed during the Darlington Refurbishment Program (DRP). The results of RQE are a high confidence estimate for which the DRP's performance will be measured against.

The DRP cost estimate considered in EB-2013-0321 was prepared while the project was still in the Definition Phase. The cost and schedule estimates were not as well developed with several estimates still at the conceptual levels (Class 5 or 4). The final scope for DRP had not been established. For the 2015 RQE Business Case, OPG had an overall Class 3 estimate with the majority of projects at Class 3 or 2 based on a fully defined project scope, and had developed an initial integrated schedule including all contractors and scopes of work and was able to determine the critical path through the Unit 2 schedule (see L-04.3-2 AMPCO-85).

There were a large number of changes in the DRP estimate, including removal of the reclassified projects, between the estimate considered in EB-2013-0321 and the high confidence RQE.

c) Please see L-2.2-1 Staff-008, part c).

As part of the development of the RQE, OPG evaluated DRP scope to ensure that it was work that had to be done to extend the life of the Darlington units and that the work could not be done as part of normal life cycle management program. Where work could be done at another time and/or where it could be done as part of the normal station life cycle management program, it was reclassified to the Nuclear Operations portfolio.

Darlington Operations Support Building (OSB) Refurbishment was reclassified because it provides services that support the daily operations of the entire station. The project provides office space for operations support staff, technical services, security systems, IT, telephone network hub etc. to the station.

Darlington (DN) Auxiliary Heating System was reclassified because it provides reliable back-up steam to the entire station when it was placed in service. Back-up steam is needed to support irregular conditions such as an event where all four turbine units are shut down in the winter, to mitigate potential major equipment damage due to freezing.

The Emergency Service Water Pipe and Component Replacement was reclassified because the project was required to ensure a safe and reliable supply of emergency service water before, during and after refurbishment.

The Primary Heat Transport Pump Motor Replacements/Overhaul was reclassified because the work was required to be completed as soon as possible (prior to refurbishment outages on certain units) in order to maintain station reliability.

The Highway 401 and Holt Road Interchange Project was reclassified because the completion of this project was necessary to provide improved traffic flow for peak staffing during regular planned outages as well as during refurbishment.

Now that the scope of the DRP is set as per the RQE, OPG does not anticipate reclassifying any further projects.

Chart 1

Reconciliation of F&IP Project List to EB-2013-0321 Ex. D2-2-1, Tables 3 and 4

Project	Project Number	EB-2013-0321	EB-2016-0152	Total Project Cost based on approved project BCS ($M)
Projects >$20M				
Heavy Water Storage and Drum Handling Facility	31555	DRP	DRP	381.1
Water & Sewer Project	73802	DRP	DRP	57.7
Darlington Energy Complex	73803	DRP	DRP	105.4
Retube Feeder Replacement Island Support Annex	73810	DRP	DRP	40.7
Refurbishment Project Office	73815	DRP	DRP	99.9
Darlington Operations Support Building Refurbishment	25619	DRP	Nuclear Operations Portfolio	62.7
Darlington Auxiliary Heating System	34000	DRP	Nuclear Operations Portfolio	99.5
Electrical Power Distribution System	73821	DRP	DRP	20.8
Projects $5M - $20M				
GM Facility Interim Office Leasehold Improvements	73806/ 73814	DRP	DRP	9.3

In addition to the projects in the table above, the following projects were reclassified as Nuclear Operations Portfolio projects:

- Emergency Service Water Pipe and Component Replacement (Project 73397, Ex. D2-1-3, Table 2d)
- Primary Heat Transport Pump Motor Replacements (Project 73566/ 80144, Ex. D2-1-3, Table 1)
- Primary Heat Transport Pump Motor Overhaul (Project 73566/ 80144, Ex. D2-1-3, Table 1)

- Highway 401 & Holt Road Interchange (Project 73706, Ex. D2-1-3, Table 1)

2.4.5 Project Variance Explanation

This section provides an explanation for F&IP greater than $20M for which total actual or forecast project cost variances exceed 10 per cent. Explanations are provided for the following projects:

- Heavy Water Storage and Drum Handling Facility (section 2.4.5.1)
- Water and Sewer (section 2.4.5.2)
- Electrical Power Distribution System (section 2.4.5.3)

Variances for F&IP are managed as part of the overall DRP. As presented in Ex. D2-2-8, F&IP represent 5 per cent of the overall DRP. There is $76M total contingency in the DRP budget that recognizes the risks associated with F&IP and SIO. The DRP is expected to be delivered on budget and on schedule, notwithstanding the variances described below.

Facility and Infrastructure Projects are significantly different from the Nuclear Operations Portfolio projects that OPG has undertaken in the past and from the unit refurbishment program. They are new designs of complex facilities constructed on a brownfield site. For instance, there are more engineering changes (discussed in section 3.1 of Ex. D2-2-5) required for F&IP than are required for the entirety of the Unit 2 refurbishment.

2.4.5.1 Heavy Water Storage and Drum Handling Facility

Overview

The purpose of the Heavy Water Storage and Drum Handling Facility (the "Heavy Water Facility") is to provide heavy water storage and processing capability for the removal of heavy water from the Darlington units during refurbishment and the management of heavy water during normal operations. Heavy water, when used in a nuclear reactor, becomes radioactive material. As a result, effective management and controls are required to avoid spills and to manage potential radiological safety and environmental consequences.

Numbers may not add due to rounding.

Table 1
Capital Project Listing - Nuclear Operations Facility Projects
Projects > $20M Total Project Cost[1]

Line No.	Facility	Project Name	Project Number	Category	Start Date	Final In-Service Date	Total Project Cost[2] (M$)	Partial/Devmt Release ($M)	Initial Full Release ($M)	Superceding Full Release ($M)	In-Service 2016 ($M)	In-Service 2017 ($M)	In-Service 2018 ($M)	In-Service 2019 ($M)	In-Service 2020 ($M)	In-Service 2021 ($M)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
		ONGOING PROJECTS FROM EB-2013-0321														
1	DN	Operations Support Building Refurbishment[3]	25619	Sustaining	Mar-09	Oct-15	62.7		53.0	62.7	3.6	0.0	0.0	0.0	0.0	0.0
2	DN	Class II Uninterruptible Power Supply Replacement[4]	31412	Sustaining	Jan-11	Jun-25	55.1	31.1			7.0	6.5	9.4	6.5	1.6	7.6
3	DN	Fukushima Phase 1 Beyond Design Basis Event Emergency Mitigation Equipment[4,5]	31508	Regulatory	Sep-11	Sep-17	52.9	51.9			17.0	13.8	0.0	0.0	0.0	0.0
4	DN	Improve Maintenance Facilities at Darlington	31717	Sustaining	Aug-07	Oct-13	43.2		43.2		0.8	0.0	0.0	0.0	0.0	0.0
5	DN	Secondary Control Area Air Conditioning Unit Replacement[4]	33621	Sustaining	Feb-09	Apr-17	28.3	25.8			10.3	6.1	0.0	0.0	0.0	0.0
6	DN	Chiller Replacement to Reduce CFC Emissions	33631	Regulatory	Jan-04	Jan-13	30.0		30.0		0.0	1.2	0.0	0.0	0.0	0.0
7	DN	Major Pump-sets Vibration Monitoring System Upgrades[4]	33819	Sustaining	Mar-06	Jul-21	23.8	9.6			0.0	0.0	5.2	4.6	4.5	4.4
8	DN	Shutdown System Computer Aging Management[4]	33955	Sustaining	Nov-06	May-16	20.3		20.3		2.0	0.0	0.0	0.0	0.0	0.0
9	DN	Standby Generator Controls Replacement	33973	Sustaining	Dec-06	May-17	39.6	32.4			17.9	8.7	0.0	0.0	0.0	0.0
10	DN	Digital Control Computer Replacement / Refurbishment / Upgrades	33977	Sustaining	Sep-03	Dec-18	24.9		22.1	24.9	0.0	2.0	1.8	0.0	0.0	0.0
11	DN	Auxiliary Heating System[3]	34000	Regulatory	Mar-06	Apr-16	99.5		89.5		94.2	0.1	0.0	0.0	0.0	0.0
12	DN	Primary Heat Transport Pump Motor Capital Spares[4]	36001	Sustaining	Sep-11	May-15	30.8		12.0	30.8	0.0	0.0	0.0	0.0	0.0	0.0
13	PN	Unit 1 & 4 Fuel Channel East Pressure Tube Shift/Reconfigure[6]	41023 49247	Sustaining	Nov-09	Mar-16	38.6		28.8	38.6	17.0	0.0	0.0	0.0	0.0	0.0
14	PN	Pickering A Fuel Handling Single Point of Vulnerability Equipment Reliability Improvement	46634	Sustaining	Feb-11	Mar-16	27.3		27.3		3.8	2.5	0.0	0.0	0.0	0.0
15	PN	Fukushima Phase 1 Beyond Design Basis Event Emergency Mitigation Equipment[4,5]	49158 49299	Regulatory	Sep-11	Aug-16	58.0	47.2			21.0	10.5	0.5	0.0	0.0	0.0
16	SEC	Physical Barrier System	25609	Regulatory	Nov-05	Dec-13	67.2		49.5	67.2	0.5	0.0	0.0	0.0	0.0	0.0
17		Subtotal					702.2				195.1	51.5	16.9	11.2	6.0	12.0
		COMPLETED/DEFERRED/CANCELLED FROM EB-2013-0321														
18	PN	PB Standby Generator Governor Upgrade	49109	Sustaining	Oct-05	Jan-15	22.8		23.3		0.0	0.0	0.0	0.0	0.0	0.0
19	PN	Modify/Replace Fiber Reinforced Plastic Components During 2010 Vacuum Building Outage	49285	Sustaining	Nov-09	Jun-10	17.7		12.8	24.5	0.0	0.0	0.0	0.0	0.0	0.0
20	ENG	Feeder Repair by Weld Overlay	62568	Value Enhancing	May-09	Deferred	0.0		53.2		0.0	0.0	0.0	0.0	0.0	0.0
21		Subtotal					40.5				0.0	0.0	0.0	0.0	0.0	0.0
		PROJECTS NOT IN EB-2013-0321														
22	DN	Restore Emergency Service Water and Firewater Margins	31518	Sustaining	Dec-12	Sep-16	47.1	28.4			2.1	0.0	33.8	0.0	0.0	0.0
23	DN	Station Roofs Replacement	31524	Sustaining	Nov-12	Deferred	38.3	0.8			0.0	15.5	8.0	0.1	0.0	0.0
24	DN	Powerhouse Water Air Conditioning Units Replacement	31532	Sustaining	Oct-12	Dec-19	20.0	11.3			0.0	4.8	3.8	3.0	5.2	0.2
25	DN	Water Treatment Plant Replacement	31535	Sustaining	Oct-12	Deferred	57.8	5.2			0.0	0.0	0.0	49.9	0.5	0.0
26	DN	Transformer Multi-Gas Analyzer Installation	31542	Sustaining	Oct-12	Mar-18	22.7		22.7		6.0	3.5	1.6	0.1	0.0	0.0
27	DN	Radiation Detection Equipment Obsolescence	31544	Sustaining	Jan-14	Dec-21	46.9	1.2			0.0	6.6	10.2	9.5	1.7	0.8
28	DN	Condenser Circulating Water and Low Pressure Service Water Traveling Screens Replacement	31552	Sustaining	May-13	Jun-18	37.6	27.5			10.6	8.4	7.2	0.1	0.0	0.0
29	DN	Shutdown Cooling Heat Exchanger Replacement	31710	Sustaining	Nov-12	May-19	56.1	38.8			15.8	9.9	14.3	0.9	0.0	0.0
30	DN	Neutron Over-Power & Ion Chamber Amplifier Replacement (Reactor Regulating System, Shutdown System 1 & Shutdown System 2)	31716	Sustaining	Jul-13	Jul-22	17.7	5.5			0.0	0.0	0.0	1.0	2.3	0.0
31	DN	Zebra Mussel Mitigation Improvements	38548	Sustaining	Nov-12	Jul-16	31.5		21.5		18.9	1.0	0.0	0.0	0.0	0.0
32	DN	Holt Road Interchange Upgrade	73706	Value Enhancing	Nov-13	Dec-16	28.6		31.0		22.4	0.0	0.0	0.0	0.0	0.0
33	DN	OH180 Aging Management Hardware Installation	80022	Sustaining	Dec-14	Dec-22	47.2	1.4			0.0	0.0	7.9	5.7	5.5	5.6
34	DN	Digital Control, Common Process and Sequence of Events Monitoring Computer Aging Management	80078	Regulatory	Nov-15	Jun-25	47.3	1.7			0.0	0.0	0.0	0.0	1.6	6.0
35	DN	Generator Stator Core Spare	80111	Sustaining	Sep-15	Jul-18	35.0		35.0		0.0	0.0	0.0	32.0	0.0	0.0
36	DN	Vault Cooling Coil Replacement	82816	Regulatory	Dec-15	Sep-20	26.3	11.9			6.9	2.4	1.3	3.8	2.9	0.0
37	DN	Primary Heat Transport Pump Motor Replacement/Overhaul[7]	73566 80144	Sustaining	May-15	Dec-22	129.5	53.8			14.8	11.0	13.0	17.0	19.2	0.0
38	PN	Pickering B Fuel Handling Reliability Modifications	40970	Sustaining	Aug-12	Jul-17	37.3	30.9			11.5	7.9	4.2	0.0	0.0	0.0
39	PN	Fukushima Phase 2 Beyond Design Basis Event Emergency Mitigation Equipment	41027	Regulatory	Oct-12	Jun-17	46.3	5.8			7.3	22.5	0.0	0.0	0.0	0.0
40	PN	Machine Delivered Scrape	66600	Value Enhancing	Feb-14	May-17	24.9	14.1	0.0	0.0	18.9	1.5	0.0	0.0	0.0	0.0
41		Subtotal					788.0				135.1	95.0	105.3	122.1	38.9	12.6
42		Total									330.2	146.5	122.2	134.3	44.9	24.6
		DIVISION TOTALS:														
43		Darlington									250.2	101.5	117.5	134.3	44.9	24.6
44		Pickering									79.4	45.0	4.7	0.0	0.0	0.0
45		Nuclear Support Divisions									0.5	0.0	0.0	0.0	0.0	0.0
46		Total									330.2	146.5	122.2	134.3	44.9	24.6

Notes:
1 Projects with expenditures during Test Period OR In-Service Amounts in Bridge or Test Period, AND Completed/Deferred Projects (from EB-2013-0321 or subsequent).
2 Total Project Cost reflects BCS amounts, with the exception of Completed/Deferred/Cancelled Projects (for which actual costs are shown).
3 Projects from Ex. D2-2-1 Table 7 in EB-2013-0321.
4 Projects from Ex. D2-1-3 Table 2 in EB-2013-0321.
5 Projects 31508, 49158 and 49299 are combined in a single Business Case Summary.
6 Projects 41023 and 49247 are combined in a single Business Case Summary. Project 49247 is from Ex. D2-1-3 Table 2 in EB-2013-0321
7 Projects 73566 and 80144 are combined in a single Business Case Summary

Numbers may not add due to rounding

Table 2d
Capital Project Listing - Nuclear Operations Facility Projects
Projects $5M - $20M Total Project Cost[1]

Line No.	Facility	Project Name	Project Number	Category	Project Description	Start Date	Final In-Service Date	Total Project Cost[2] ($M)	In-Service 2016 ($M)	In-Service 2017 ($M)	In-Service 2018 ($M)	In-Service 2019 ($M)	In-Service 2020 ($M)	In-Service 2021 ($M)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
		PROJECTS NOT IN EB-2013-0321												
45	DN	DN Dryer PLC Replacement	31420	Sustaining	Replace obsolete programmable logic controllers.	Feb-14	Mar-22	12.2	0.0	0.0	2.7	0.0	2.6	1.1
46	DN	DN Containment Button-up Activity Monitors Replacement	31432	Regulatory	Replace aging and obsolete radioactivity monitors used to button up the Negative Pressure Containment System on high activity.	Nov-13	Oct-19	8.0	0.0	1.2	1.8	2.8	0.8	0.0
47	DN	DN Computer Upgrade for HWMS (TRF/SUP)	31436	Sustaining	Upgrade obsolete Heavy Water Management System computers that control Tritium Removal Facility and Station Upgrader operations.	Oct-12	Feb-16	5.9	3.7	0.0	0.0	0.0	0.0	0.0
48	DN	DN Replacement of Obsolete Online Chemistry Analysers	31520	Sustaining	Replace obsolete online chemistry analysers	Oct-12	Nov-17	10.6	4.3	4.3	0.0	0.0	0.0	0.0
49	DN	DN RRS Logic Module Redesign	31534	Sustaining	Redesign the Regulator Regulating System logic modules to address spurious rod movements as well as addressing obsolescence of current modules.	Dec-13	May-26	9.9	0.0	0.0	0.0	0.0	0.0	5.3
50	DN	DN Feedwater Chemistry Control Improvements	31548	Sustaining	Install improved feedwater chemistry monitoring and connections for portable filtration.	Nov-13	Nov-22	10.3	0.0	2.2	1.8	2.1	0.0	0.0
51	DN	DN Fukushima Phase 2 Beyond Design Basis Event Emergency Mitigation Equipment	32202	Regulatory	Provide capability to respond to Beyond Design Basis Events following the events at Fukushima Daiichi Nuclear Power Plant	Sep-11	Dec-17	28.0	6.9	7.6	0.1	0.0	0.0	0.0
52	DN	DN EPG Power Turbine Capital Spare	36004	Regulatory	Purchase a spare Emergency Power Generator power turbine to mitigate risk of engine failure.	May-13	Mar-17	8.1	0.0	4.5	0.0	0.0	0.0	0.0
53	DN	DN CSA Sewage Line and Sump Emergency Connections	38466	Sustaining	Replace corroded and degraded sewage piping from Central Services Area and add emergency connections to allow sewage truck to empty sump in emergencies.	Jul-13	Dec-17	7.9	0.0	6.4	0.1	0.0	0.0	0.0
54	DN	DN ESW Pipe and Component Replacement	73397	Sustaining	Replacement of degraded Emergency Service Water piping, valves and tanks during the 2015 Vacuum Building Outage.	Feb-14	Sep-15	6.7	0.3	0.0	0.0	0.0	0.0	0.0
55	DN	DN Large Steam Generator LCV Replacement	80023	Sustaining	Install new large Steam Generator level control valve actuators, valve trims and positioners to address operational and maintenance issues with current valves.	Jan-15	Oct-22	16.3	0.0	0.0	2.7	2.5	2.6	0.0
56	DN	DN R22 Refrigerant ACU Replacement	80036	Regulatory	Replace 51 air conditioning/dehumidifying units containing refrigerant R22 with units using approved non-ozone depleting refrigerant	Jan-16	Oct-21	14.9	0.0	0.0	3.9	4.1	3.8	0.0
57	DN	DN Feeder Scanner Replacement (CMFA)	80070	Sustaining	Replace permanent feeder scanner equipment with portable system that can be setup outside of containment prior to use.	May-14	Mar-19	8.0	0.0	1.8	1.8	3.4	0.0	0.0
58	DN	DN FHA and FSSA Modifications	80151	Regulatory	Implement modifications required for compliance to Canadian Standards Association N293-07 Fire Protection for Nuclear Power Plants identified in the updated Fire Hazard Assessment and Fire Safe Shutdown Analysis prepared during the Integrated Safety Review and committed in the Integrated Implementation Plan.	Nov-15	Jan-19	6.8	0.0	0.0	0.5	4.7	0.0	0.0
59	DN	DN Irradiated Fuel Discharge Mechanism Major Component Replacement	82841	Sustaining	Replace the shuttle cylinders and other major components of the Irradiated Fuel Discharge system which are approaching end of design life.	Nov-15	Dec-22	5.9	0.0	0.0	0.0	0.0	0.0	5.2
		Table continues on Ex. D2-1-3 Table 2e												

Notes:
1 Projects with expenditures during Test Period OR In-Service Amounts in Bridge or Test Period, AND Completed/Deferred Projects (from EB-2013-0321 or
2 "Total Project Cost" reflects BCS amounts, with the exception of Completed/Deferred Projects (for which actual costs are shown).

COSTS OF ENVIRONMENTAL ASSESSMENT FOLLOW-UP STUDIES

In its decision in EB-2013-0321, the OEB required OPG to file at its next proceeding updates of actual costs of Environmental Assessment ("EA") follow-up studies.[1] Actual costs related to the environmental studies, monitoring and adaptive management projects required by the Darlington Refurbishment Program EA and follow-up program are provided in Chart A-1 below. There are no adaptive management programs at this stage of the program. They will be developed, if needed, based on the results of initial monitoring studies. It is important to note that these costs are not all for DRP and that these do not reflect all EA costs for the DRP.

Chart A-1

Actual Costs of EA Follow-up Studies

Project Work Package Description		**Actual Spent**		
		2013	**2014**	**2015**
EA Follow-up Studies	Effluent Characterization	$0 K	$5 K	$7 K
	Fisheries Authorization	$0 K	$25 K	$0 K
	Entrainment Study	$0 K	$25 K	$198 K
	Benthic Invertebrate Community Study	$0 K	$25 K	$0 K
	Thermal Monitoring	$0 K	$20 K	$0 K
	Stormwater Control Study	$0 K	$0 K	$0 K
Environmental Monitoring Studies	Groundwater monitoring, sampling and analysis for chemical waste, groundwater wells	$170 K	$270 K	$370 K
	Biodiversity studies and monitoring	$40 K	$50 K	$50 K
	Chemistry laboratory cost for supporting environmental monitoring[2]	$3.1 M	$3.1 M	$3.2 M
	Stack and filter testing emission verification	$285 K	$190 K	$160 K
	Radiological Environmental Monitoring Program	$150 K	$260 K	$160 K
Adaptive Management Projects		$0 K	$0 K	$0 K

[1] EB-2013-0321, Decision with Reasons, November 20, 2014, p. 55.

[2] Chemistry laboratory costs include both environmental monitoring costs and station chemistry control costs. The value in the chart represents 50 per cent of chemistry laboratory costs as an approximation of the costs associated with environmental monitoring.

ONTARIOPOWER GENERATION

Records File Information:
Final Security Classification of the completed form is determined below
00120.3 - P For Nuclear
08707.021 - P For All Others

OPG-FORM-0077-R001*

Project Over-Variance Approval

Final Security Classification of the BCS: **OPG Confidential**

This form should not be used for over-variances in excess of 20% of cost or schedule or both. Submit this form with attachment of the latest approved Business Case Summary.

Part A: Project Information

Project #:	16-25619	**Title:**	Operations Support Building Refurbishment			
Phase:	Execution	**Class:**	Capital	**Records File:**	D-BCS-28110-10004	

	LTD	2015	2016	2017	Future	Total
Current Approval	28,233k	23,949k	848k			53,030k
Amount Requested	-	8,773k	890k			9,663k
New Total Release	**28,233k**	**32,722k**	**1,738k**			**62,693k**

Brief Description of the Project:

The OSB was constructed in 1982 with the third floor added in 1988. It is an important facility that houses technical services essential to the business operations of Darlington (DNGS). These technical services include: site security systems, site information technology (IT) and telephone network hubs, quality assurance vault, station domestic water piping and radiological public domain access to the powerhouse via the bridge. A unique requirement for this project is to maintain the operation of these technical services amidst construction activities.

The facility has the capacity to house approximately 375 Darlington employees who provide daily operations, maintenance and administrative support to station and control room staff. An assessment by an external engineering firm determined that many of the existing building systems were expected to be life expired by 2015. These systems needed to be replaced to maintain a healthy environment for employees and essential technical services, as well as to minimize corrective maintenance on expired systems. The refurbished building is designed with energy efficiency and occupancy comfort in mind.

Reason for Schedule Variance:

The project is currently scheduled to meet the Available for Service milestone of October 30, 2015 as committed to in the execution-full BCS. There is a risk that challenges during the commissioning phase of the project could threaten this milestone. This risk is being mitigated through the hiring of a commissioning agent to execute this work in an efficient manner.

Reason for Cost Variance:

The EPC contract value budgeted in the execution-full business case summary (BCS) was $37.7M. The contractor is now forecasting to spend a total of $51.8M, not including any additional discovery issues and challenges during commissioning not yet known by the project team (for which $1.5M in contingency is now being requested to cover).

Of the $14.4M contract cost variance, $11.7M is attributed to the EPC Contractor underestimating the effort required to complete the contract scope. OPG is required to pay these additional costs since the contract is cost reimbursable. The variance is summarized by the following issues:

1) The design subcontractor was required to complete revisions to the design packages due to incomplete details from the original documentation.
2) The procured equipment and construction work required to complete the design revisions has now increased significantly beyond budget due to the design packages being complex.
3) The contractor is behind schedule compared to their original plan as documented in the contract, which has resulted in additional contractor project management and engineering field support.

The remainder of the contract cost variance can be linked to a few contract scope changes, totalling $2.7M. These changes include:

1) Upgrade of motor control electrical distribution equipment
2) Additional cabling and hardware to support changes to IT and telephone requirements
3) Changes to furniture and building layout requirements as requested by building occupants

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Project Over-Variance Approval

4) Upgrades to the fire separation of civil structures that were previously hidden
5) Repairs to the exterior walk ways and soffits
6) Other minor architectural, mechanical, electrical changes

In the execution- full release, $2.6M of specific contingency was included to cover the above EPC contract issues including the discovery of unknowns as well as the under-estimation of effort required to complete a building refurbishment.

During construction the project has realized some other specific risks, requiring the partial use of the contingency from the execution-full BCS.

1) Discovery and planned remediation of mould: $0.4M increase to budget ($0.7M contingency specified in BCS)
2) Hiring of a commissioning agent to ensure an efficient building start-up, minimizing the impact of commissioning issues on the overall project: $0.1M increase to budget ($1.1M contingency specified in BCS)
   a. The remainder of the commissioning risk has not yet been realized as this process is just beginning.

The remaining risks with specific contingency allocated from the execution-full BCS have either not yet been realized or have been mitigated without the need for utilizing contingency funding.

The project has also required additional support from OPG engineering to provide oversight of the EPC contract design subcontractor as they completed the design revisions. This has resulted in an increase of $0.5M to the project budget.

The project is still developing a list of spare inventories that will need to be procured by OPG to operate and maintain this facility once the project is complete. An initial list is being reviewed by the operations and maintenance team to ensure only required spares are eventually purchased. A preliminary estimate of the spare inventory costs is $50k.

Options Considered to Mitigate Overruns:

The project team has been performing weekly reviews of the EPC contractor's project cost, schedule and risks to validate assumptions and to help overcome challenges. As an example, the project team reduced the impact on critical path created by the fire detection design package revisions by securing stakeholder concurrence to procure and install fire detection devices with minimal probability that the design would change.

The project has also been having frequent meetings and walk downs with the project sponsor and other stakeholders to seek early resolution of deficiencies that would otherwise delay eventual turnover of the building to the operations and maintenance team.

As the design and construction work has evolved, the OPG project team has continually reviewed the project scope and removed specific scope items where possible. This includes:

1) The simplification of internal governance documentation requirements to align with commercial building applications
2) Utilizing more cost effective ceiling tiles
3) The removal of exterior light distribution shelves around the perimeter of the office space

The hiring of the expert commissioning agent is expected to yield efficiencies in the commissioning process as well as reduce the impact of discovered challenges when energizing equipment.

The project actual costs to date include invoices submitted by the EPC contractor that are being disputed by OPG. As such, there is an opportunity to remove $1.0M from the project costs if OPG is successful with the disputes.

When the project removed the existing motor control centre equipment prior to their replacement, the existing circuit breakers and associated electrical equipment were transferred to the maintenance department as useful spares. This obsolete equipment has become costly for the nuclear station to have reverse engineered. This effort may not mitigate the project overruns directly however it is expected to yield overall savings to OPG.

Project Status:

At the time of execution-full business case summary approval in May 2014, the project had been completing demolition and procuring schedule critical equipment and materials. Since then, the project has progressed with significant procurement and construction work, including:

1) Procurement of all schedule critical equipment and materials
2) Installation of the new exterior curtain wall and roof membrane, leaving the building water tight
3) Mechanical, electrical, instrumentation and controls systems installation throughout the 1st, 2nd and 3rd floors

Project Over-Variance Approval

4) Elevator and associated controls are fully operational with all regulatory approvals received
5) Substantial completion of furniture installation on the 2nd and 3rd floors
6) The motor control centres have been replaced and are operational.
7) Major mechanical equipment and associated piping such as chillers, ventilation units, pumps located in the basement has been installed.
8) Routing of IT and telephone cabling throughout the building in progress
9) Fire sprinkler system pipe work installation completed on 1st, 2nd and 3rd floors
10) Kitchen/cafeteria architectural finishes and mounting of equipment is complete.
11) Overhead lighting on the 1st, 2nd and 3rd floors is operational
12) Heating, ventilation and air conditioning system flushing and equipment commissioning is in progress

The above work has progressed with a good safety and environmental record and has been completed with no impacts to the essential services located in the building, nor creating an impact to the nuclear station electrical and mechanical systems that the OSB systems depend on.

ONTARIOPOWER GENERATION

Records File Information:
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OPG-FORM-0077-R001*

Project Over-Variance Approval

Part B: Variance Detail

k$	Current Approval	Amount Requested	Variance	Comments
OPG Project Management	4,298	3,627	(671)	Project management oversight on the project has required less effort than initially planned.
OPG Engineering (Including Design)	662	1,162	500	Revisions to the designs based on field challenges during construction have required an increase in the OPG design oversight.
OPG Procured Non-Fixed Assets (IT/Telephone)	895	1,000	105	Building occupants have identified additional IT equipment to be purchased.
OPG IT/Telephone Service Provider Installation Costs	470	500	30	Building occupants have identified additional IT equipment to be installed.
Design Contract(s)	596	596	0	All standalone design contracts have been completed.
Construction Contract(s)	0	0	0	All construction work is being completed as part of the EPC contract.
EPC Contract(s)	40,278	49,119	8,841	As discussed in the cost variance section.
Consultants	0	0	0	
EPC Procured Non-Fixed Assets (Furniture)	2,500	2,712	212	Building occupants have identified changes to the ground floor layout that requires some additional furniture to be procured. There were also minor changes to the design requiring changes to the furniture procured.
Interest	3,331	2,477	(854)	The amount of interest required was overestimated in the previous release. The updated interest from now until project completion is based on most recent cash flows.
Subtotal	**53,030**	**61,193**	**8,163**	
Contingency	0	1,500	1,500	Contingency is required for estimate inaccuracy and for the possible realization of unknowns, particularly during the commissioning phase.
Total	**53,030**	**62,693**	**9,663**	
Removal Costs Included	2,540	983	(1557)	The amount requested is based on the actual spent; no further removal costs planned.

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ONTARIOPOWER GENERATION

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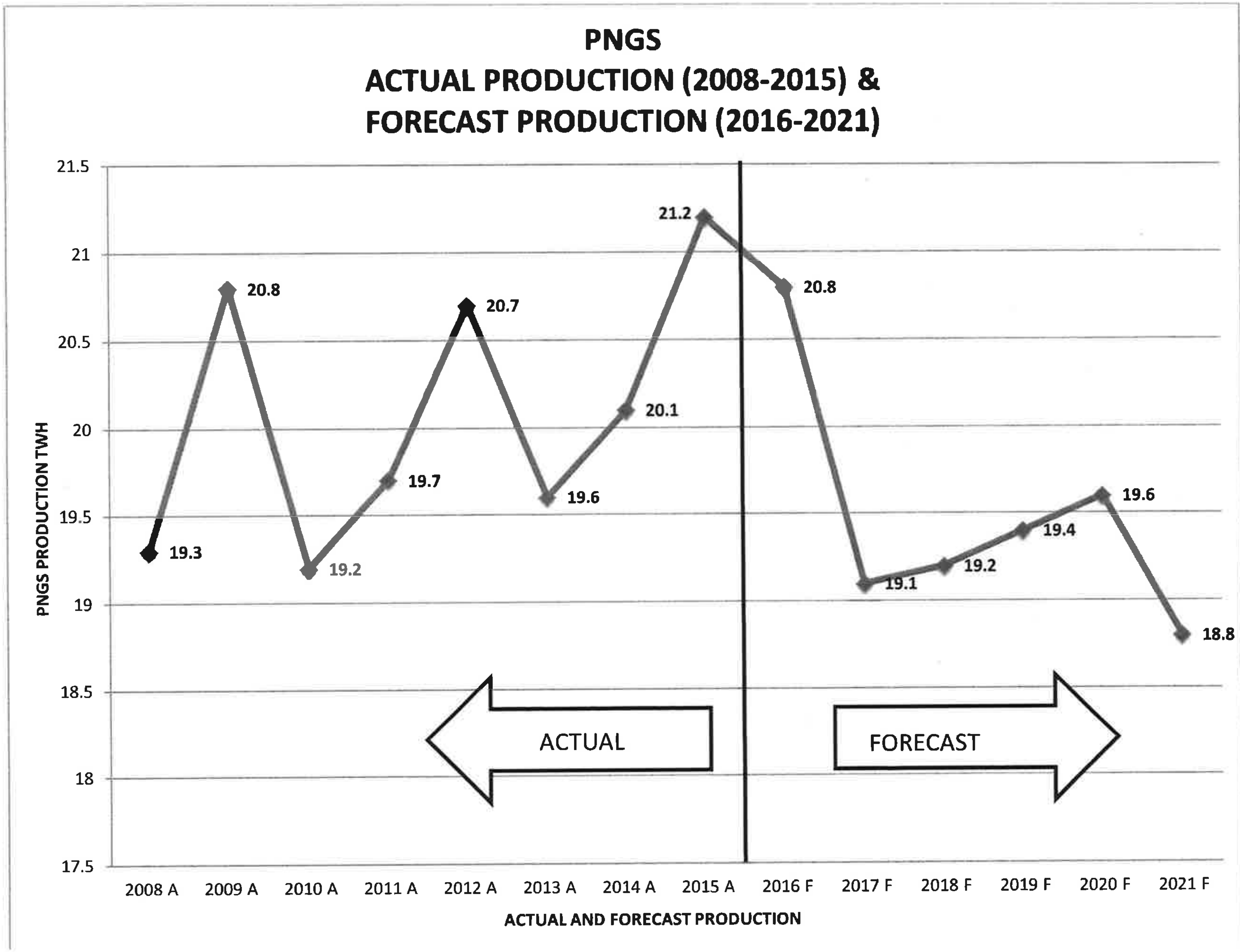
OPG-FORM-0077-R001*

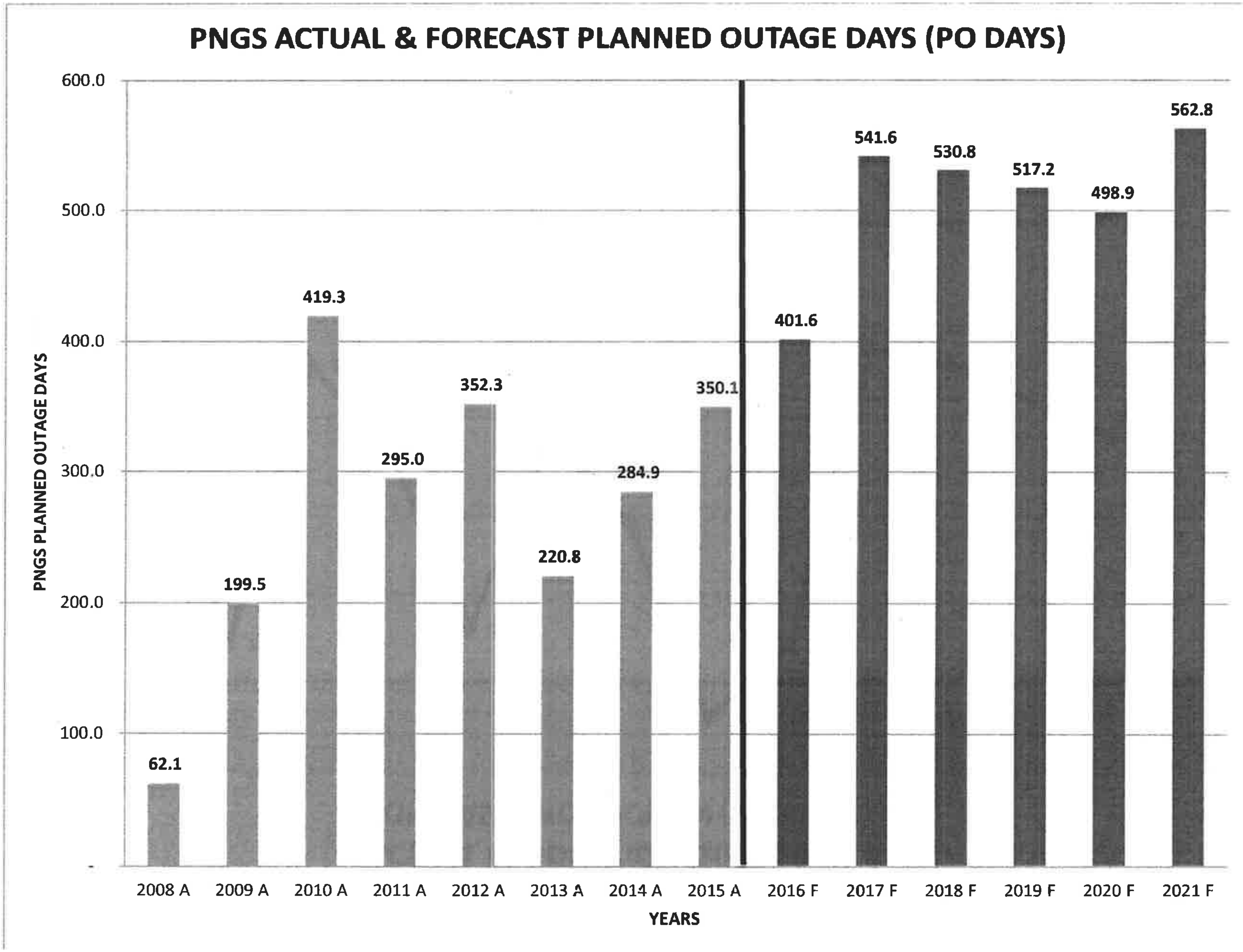
Project Over-Variance Approval

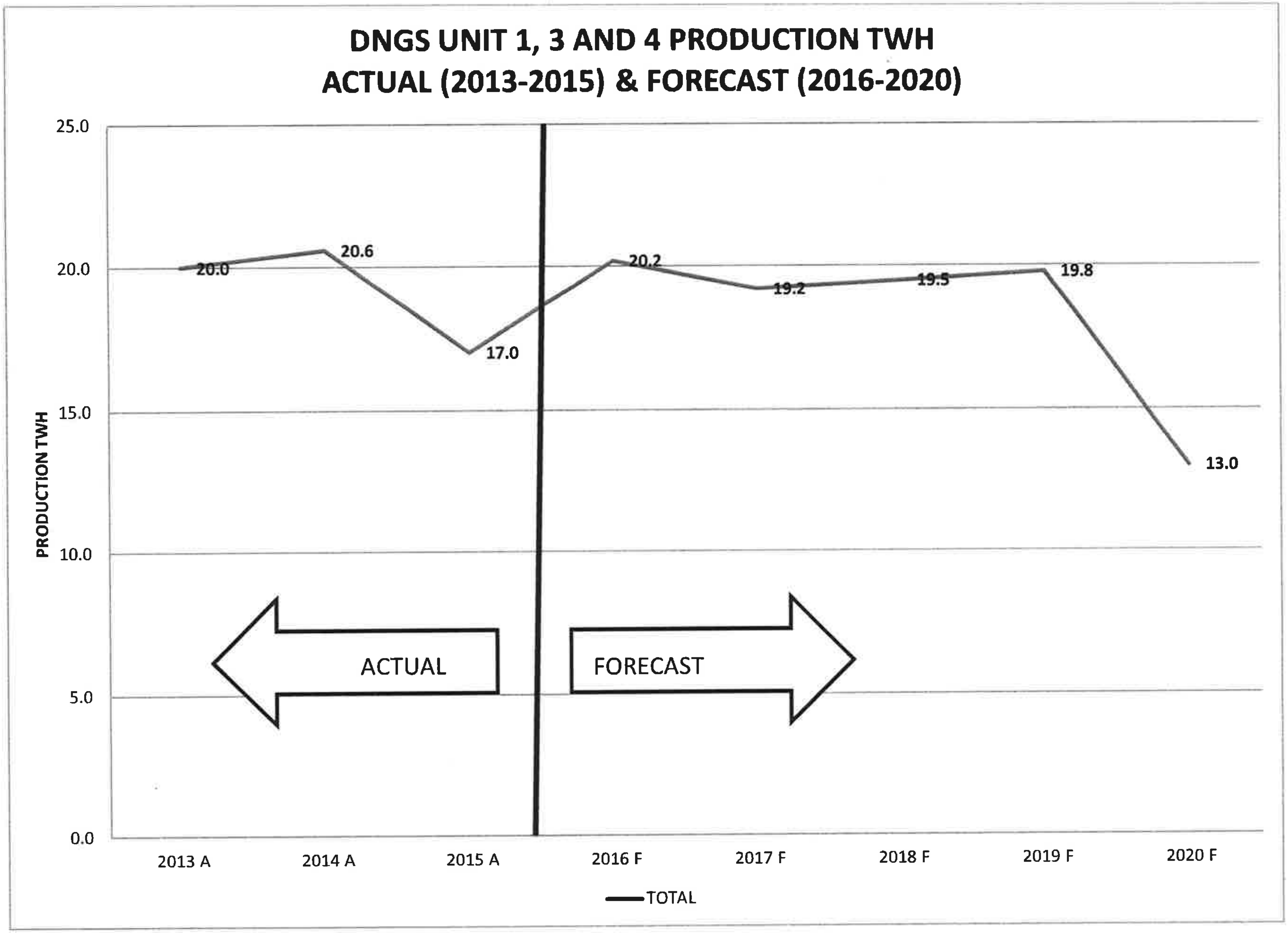
Part C: Review/Approvals			
	Signature	Comments	Date
Recommended by: Glenn Jager Chief Nuclear Officer Project Sponsor			August 7, 2015
Finance Approval: Beth Summers Chief Financial Officer		• REQUEST FOLLOW-UP TO UNDERSTAND ROOT CAUSES FOR FINAL VARIANCE	August 7, 2015.
Approved by: Tom Mitchell President and CEO Per OAR Element 1.1			AUG 8 2015

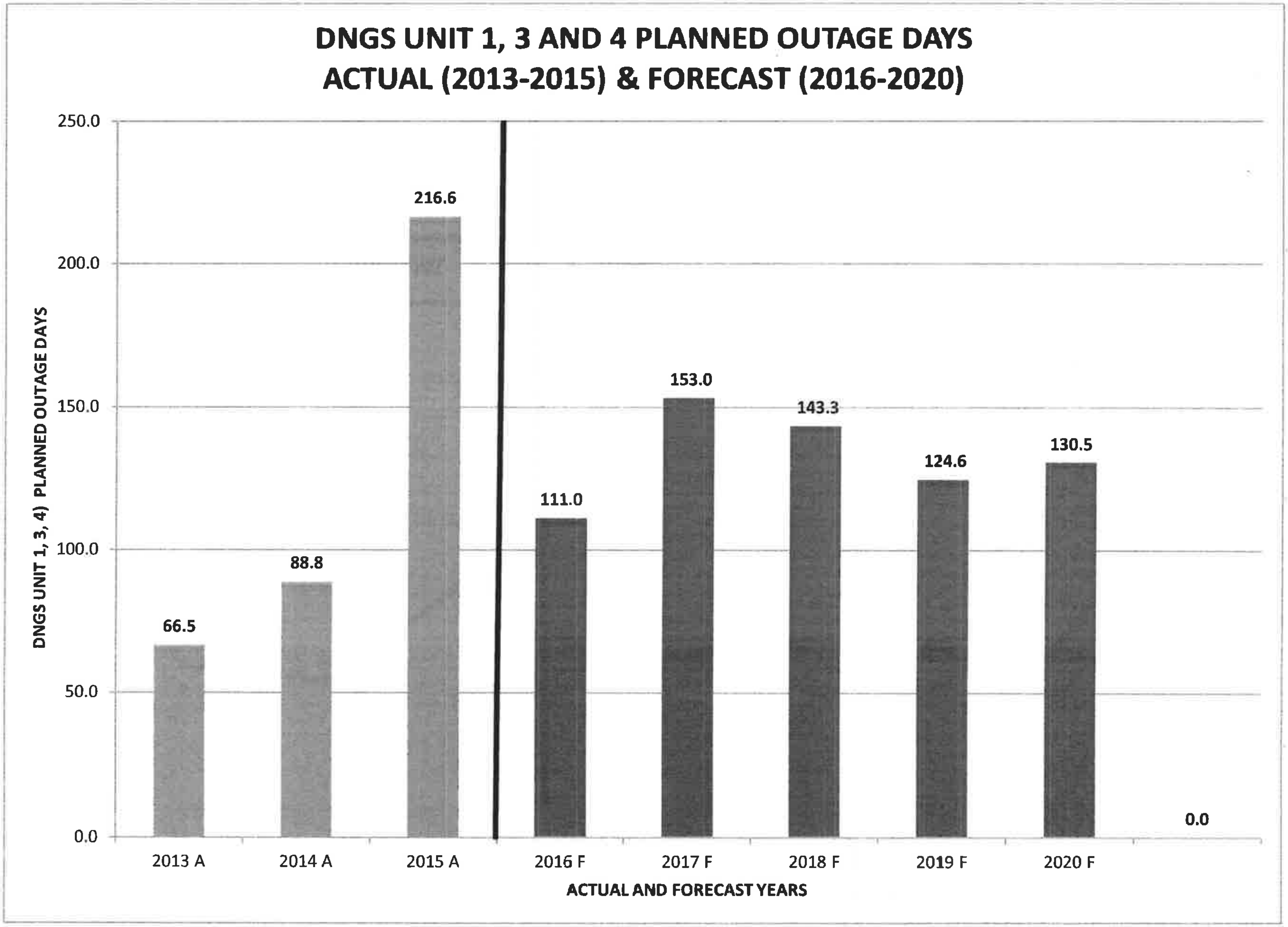
• This is poor performance. A C2 SRR is to be raised and the results of the review to be presented to the CNO. In addition ~~[illegible]~~ Art Rob is to present to the CNO what performance management follow-up is required with OPG and vendor staff ~~[illegible]~~. At this point there is little option but to approve the costs.

Agree


PNGS
ACTUAL PRODUCTION (2008-2015) &
FORECAST PRODUCTION (2016-2021)
PNGS PRODUCTION TWH
21.5
21
20.5
20
19.5
19
18.5
18
17.5
19.3
20.8
19.2
19.7
20.7
19.6
20.1
21.2
20.8
19.1
19.2
19.4
19.6
18.8
ACTUAL
FORECAST
2008 A
2009 A
2010 A
2011 A
2012 A
2013 A
2014 A
2015 A
2016 F
2017 F
2018 F
2019 F
2020 F
2021 F
ACTUAL AND FORECAST PRODUCTION


PNGS ACTUAL & FORECAST PLANNED OUTAGE DAYS (PO DAYS)
PNGS PLANNED OUTAGE DAYS
600.0
500.0
400.0
300.0
200.0
100.0
62.1
199.5
419.3
295.0
352.3
220.8
284.9
350.1
401.6
541.6
530.8
517.2
498.9
562.8
2008 A
2009 A
2010 A
2011 A
2012 A
2013 A
2014 A
2015 A
2016 F
2017 F
2018 F
2019 F
2020 F
2021 F
YEARS


DNGS UNIT 1, 3 AND 4 PRODUCTION TWH
ACTUAL (2013-2015) & FORECAST (2016-2020)
PRODUCTION TWH
25.0
20.0
15.0
10.0
5.0
0.0
20.0
20.6
17.0
20.2
19.2
19.5
19.8
13.0
ACTUAL
FORECAST
2013 A
2014 A
2015 A
2016 F
2017 F
2018 F
2019 F
2020 F
TOTAL


DNGS UNIT 1, 3 AND 4 PLANNED OUTAGE DAYS
ACTUAL (2013-2015) & FORECAST (2016-2020)
DNGS UNIT 1, 3, 4) PLANNED OUTAGE DAYS
250.0
200.0
150.0
100.0
50.0
0.0
66.5
88.8
216.6
111.0
153.0
143.3
124.6
130.5
0.0
2013 A
2014 A
2015 A
2016 F
2017 F
2018 F
2019 F
2020 F
ACTUAL AND FORECAST YEARS

COMPARING OPG'S TEST YEAR PO DAYS (2016-2020) WITH HISTORICAL ACTUALS

YEAR	PNGS PO DAYS
2008 A	62.1
2009 A	199.5
2010 A	419.3
2011 A	295.0
2012 A	352.3
2013 A	220.8
2014 A	284.9
2015 A	350.1
2016 F	401.6
2017 F	541.6
2018 F	530.8
2019 F	517.2
2020 F	498.9
2021 F	562.8
AVERAGE (2016-2020)	498.0

PEO PO DAYS (2016-2020) OPG ESTIMATE	637.0
AVERAGE PEO PO DAYS/YEAR [637/5]	127.4

-159 days (2017-2020)

AVERAGE (2016-2020) Normalized for PEO 370.6 [498.0 LESS 127.4]

338

COMPARING NORMALIZED FOR PEO WITH HISTORY		VARIANCE	NOTES
AVERAGE (2008-2015)	273.0	65 97.6	Even after normalizing for PEO, the 2016-2020 PO DAYS estimate is higher than Average Actual experience in the 2008-2015 period [i.e. 370.6 less 273.0]
AVERAGE (2011-2015)	300.6	38 70.0	Even after normalizing for PEO, the 2016-2020 PO DAYS estimate is higher than Average Actual experience in last 5 years (2011-2015) [i.e. 370.6-300.6]
AVERAGE (5 HIGHEST -2008-2015)	340.3	2 30.3	Even after normalizing for PEO, the 2016-2020 PO DAYS estimate is higher than Average of the 5 highest years of PO days in 2008-2015. [i.e. 370.6-340.3]

PICKERING (UNITS 1, 4, 5, 6, 7 & 8) PRODUCTION (TWH) AND PLANNED OUTAGE (DAYS) DATA

	ACTUAL PNGS PRODUCTION TWH (2008-2015) AND FORECAST PNGS PRODUCTION TWH (2016-2021)													
	2008 A	2009 A	2010 A	2011 A	2012 A	2013 A	2014 A	2015 A	2016 F	2017 F	2018 F	2019 F	2020 F	2021 F
PNGS PROD TWH	19.3	20.8	19.2	19.7	20.7	19.6	20.1	21.2	20.8	19.1	19.2	19.4	19.6	18.8
								AVG (2013-16)	20.4		AVG(2017-19)	19.2		
								AVG (2008-16)	20.2		AVG(2017-21)	19.2		

Source: 2008 and 2009 Data from EB-2010-0C08, E2-T1-S2-Table 1b
Source: 2010, 2011, 2012 Data from EB-2013-0321, E2-T1-S2-Table 1
Source: 2013-2021 Data from EB-2016-0152, E2-T1-S2-Table 1

	ACTUAL PNGS PLANNED OUTAGE DAYS (2008-2015) AND FORECAST PLANNED OUTAGE DAYS (2016-2021)													
	2008 A	2009 A	2010 A	2011 A	2012 A	2013 A	2014 A	2015 A	2016 F	2017 F	2018 F	2019 F	2020 F	2021 F
PNGS PO DAYS	62.1	199.5	419.3	295.0	352.3	220.8	284.9	350.1	401.6	541.6	530.8	517.2	498.9	562.8
								AVG (2013-16)	314.4		AVG(2017-19)	529.9		
								AVG (2008-16)	287.3		AVG(2017-21)	530.3		

Source: 2008 and 2009 Data from EB-2010-0C08, E2-T1-S2-Table 1b
Source: 2010, 2011, 2012 Data from EB-2013-0321, E2-T1-S2-Table 1
Source: 2013-2021 Data from EB-2016-0152, E2-T1-S2-Table 1

DARLINGTON (UNIT 1, 3 & 4) PRODUCTION (TWH) AND PLANNED OUTAGE (DAYS) DATA

DNGS UNIT 1, 3, 4 PRODUCTION (TWH) ACTUAL (2013-2015) & FORECAST (2016-2021)

	2013 A	2014 A	2015 A	2016 F	2017 F	2018 F	2019 F	2020 F	2021 F
D1	7.5	5.8	5.5	7.5	5.2	7.1	7.0	5.2	n/a
D3	7.3	7.5	5.0	7.1	7.0	5.3	7.4	0.8	n/a
D4	5.2	7.3	6.5	5.6	7.0	7.1	5.4	7.0	n/a
TOTAL	**20.0**	**20.6**	**17.0**	**20.2**	**19.2**	**19.5**	**19.8**	**13.0**	**n/a**
		AVG (2013-2016)		19.5	AVG (2017-2019)		19.5		

Source: 2013-2015 Actual Production Data from Ex L-T5.1-S20-VECC 019, Attachment 1
Note: DNGS Unit Level Production Data not available for 2008-2012 and 2021

DNGS UNIT 1, 3, 4 PLANNED OUTAGE DAYS ACTUAL (2013-2015) & FORECAST (2016-2021)

	2013	2014	2015	2016	2017	2018	2019	2020	2021
D1	0	77	72	0	108.0	20.0	23.0	108	n/a
D3	0	0	95.8	20	22.5	103.3	2.5	0	n/a
D4	66.5	11.8	48.8	91	22.5	20.0	99.1	22.5	n/a
TOTAL	**66.5**	**88.8**	**216.6**	**111.0**	**153.0**	**143.3**	**124.6**	**130.5**	**0.0**
		AVG (2013-2016)		120.7	AVG (2017-2019)		140.3		

Source: 2013-2015 Actual PO Days Data from Ex L-T5.1-S20-VECC 019, Attachment 1
Note: DNGS Unit Level PO Days Data not available for 2008-2012 and 2021

Table 1
Comparison of Production Forecast - Nuclear

Line No.	Business Unit	2013 Budget	(c)-(a) Change	2013 Actual	(g)-(c) Change	2014 OEB Approved[1]	(g)-(e) Change	2014 Actual	(k)-(g) Change	2015 OEB Approved[2]	(k)-(i) Change	2015 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Darlington NGS											
1	TWh	26.9	(1.8)	25.1	2.9	27.1	0.9	28.0	(4.7)	25.0	(1.7)	23.3
2	Unit Capability Factor (%)	88.8	(5.9)	82.9	9.0	93.5	(1.6)	91.9	(15.0)	86.3	(9.4)	76.9
3	PO Days	144.4	0.1	144.5	(52.4)	77.1	15.0	92.1	174.8	188.0	78.9	266.9
4	FEPO Days	0.0	39.8	39.8	(39.8)	0.0	0.0	0.0	7.7	0.0	7.7	7.7
5	FLR (%)	1.5	3.3	4.8	(3.3)	1.3	0.3	1.5	3.4	1.0	3.9	4.9
6	FLR Days Equivalent	10.7	41.8	61.6	(41.0)	14.0	5.9	20.5	30.9	12.7	44.7	57.4
	Pickering NGS											
7	TWh	21.1	(1.5)	19.6	0.5	21.9	(1.8)	20.1	1.1	21.6	(0.4)	21.2
8	Unit Capability Factor (%)	79.2	(5.5)	73.7	1.6	79.9	(4.6)	75.3	4.1	82.1	(2.8)	79.4
9	PO Days	303.5	(82.7)	220.8	64.1	292.9	(8.0)	284.9	65.2	287.9	62.2	350.1
10	FEPO Days	0.0	167.6	167.6	(112.2)	0.0	55.4	55.4	(14.8)	0.0	40.6	40.6
11	FLR (%)	8.1	1.6	9.7	1.0	7.8	3.0	10.7	(7.8)	5.5	(2.6)	2.9
12	FLR Days Equivalent	152.4	21.4	173.8	24.2	147.0	51.0	198.0	(146.3)	104.5	(52.8)	51.7
	Totals											
13	Unit Capability Factor (%)	84.3	(5.7)	78.6	5.7	87.6	(3.3)	84.3	(6.3)	84.0	(6.0)	78.0
14	PO Days	447.9	(82.6)	365.3	11.7	370.0	7.0	377.0	239.9	475.9	141.0	616.9
15	FEPO Days	0.0	207.4	207.4	(152.0)	0.0	55.4	55.4	(7.1)	0.0	48.3	48.3
16	FLR (%)	4.5	2.5	7.0	(1.5)	4.1	1.5	5.6	(1.6)	3.1	0.8	3.9
17	FLR Days Equivalent	172.1	63.2	235.3	(16.8)	161.6	56.9	218.5	(109.4)	117.2	(8.1)	109.1
18	Total TWh	48.0	(3.3)	44.7	3.4	49.0	(0.9)	48.1	(3.5)	46.6	(2.1)	44.5

Line No.	Business Unit	2015 Actual	(c)-(a) Change	2016 Budget	(e)-(c) Change	2017 Plan	(g)-(e) Change	2018 Plan	(i)-(g) Change	2019 Plan	(k)-(i) Change	2020 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Darlington NGS											
19	TWh	23.3	2.7	26.0	(7.0)	19.0	0.2	19.3	0.4	19.7	(1.9)	17.7
20	Unit Capability Factor (%)	76.9	14.2	91.1	(5.9)	85.1	0.9	86.0	1.7	87.8	(8.4)	79.4
21	PO Days[3]	266.9	(155.9)	111.0	42.4	153.4	(10.1)	143.3	(19.2)	124.1	64.1	188.2
22	FEPO Days	7.7	(7.7)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	FLR (%)	4.9	(3.9)	1.0	0.0	1.0	(0.0)	1.0	0.0	1.0	3.2	4.2
24	FLR Days Equivalent	57.4	(44.7)	12.7	(3.3)	9.4	0.1	9.5	0.2	9.7	28.4	38.1
	Pickering NGS											
25	TWh	21.2	(0.4)	20.8	(1.7)	19.1	0.1	19.2	0.2	19.4	0.3	19.0
26	Unit Capability Factor (%)	79.4	(1.7)	77.6	(6.1)	71.5	0.5	72.0	0.6	72.6	0.8	73.4
27	PO Days	350.1	51.5	401.6	140.0	541.6	(10.8)	530.8	(13.7)	517.2	(18.3)	498.9
28	FEPO Days	40.6	(40.6)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
29	FLR (%)	2.9	2.1	5.0	0.0	5.0	(0.0)	5.0	0.0	5.0	0.0	5.0
30	FLR Days Equivalent	51.7	38.0	89.7	(7.2)	82.4	0.5	83.0	0.7	83.6	1.2	84.9
	Totals											
31	Unit Capability Factor (%)	78.0	6.6	84.6	(6.8)	77.8	0.7	78.5	(39.5)	39.0	37.2	76.2
32	PO Days[3]	616.9	(104.3)	512.6	182.4	695.0	(20.8)	674.1	(32.9)	641.3	45.8	687.1
33	FEPO Days	48.3	(48.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	FLR (%)	3.9	(1.1)	2.8	0.2	3.0	(0.0)	3.0	(0.0)	3.0	1.6	4.6
35	FLR Days Equivalent	109.1	(6.7)	102.4	(10.6)	91.8	0.6	92.5	0.9	93.4	29.6	122.9
36	Total TWh	44.5	2.3	46.8	(8.7)	38.1	0.4	38.5	0.6	39.0	(1.7)	37.4

Line No.	Business Unit	2020 Plan	(c)-(a) Change	2021 Plan
		(a)	(b)	(c)
	Darlington NGS			
37	TWh	17.7	(1.1)	16.6
38	Unit Capability Factor (%)	79.4	11.5	90.9
39	PO Days[3]	188.2	(131.9)	56.2
40	FEPO Days	0.0	0.0	0.0
41	FLR (%)	4.2	(1.2)	3.0
42	FLR Days Equivalent	38.1	(13.1)	25.0
	Pickering NGS			
43	TWh	19.6	(0.8)	18.8
44	Unit Capability Factor (%)	73.4	(2.8)	70.6
45	PO Days	498.9	63.9	562.8
46	FEPO Days	0.0	0.0	0.0
47	FLR (%)	5.0	(0.0)	5.0
48	FLR Days Equivalent	84.9	(3.5)	81.4
	Totals			
49	Unit Capability Factor (%)	76.2	2.8	79.0
50	PO Days[3]	687.1	(68.1)	619.0
51	FEPO Days	0.0	0.0	0.0
52	FLR (%)	4.6	(0.6)	4.0
53	FLR Days Equivalent	122.9	(16.6)	106.3
54	Total TWh	37.4	(2.0)	35.4

Notes:

1 OEB Approved nuclear production in 2014 is 49.0 TWh per EB-2013-0321 Decision with Reasons p. 39.
2 OEB Approved nuclear production in 2015 is 46.6 TWh per EB-2013-0321 Decision with Reasons p. 39.
3 PO days excludes planned outage days for Darlington units out of service during Darlington refurbishment.

Numbers may not add due to rounding.

Table 1
Comparison of Production Forecast - Nuclear

Line No.	Prescribed Facility	2010 Budget	(c)-(a) Change	2010 Actual	(g)-(c) Change	2011 Board Approved	(g)-(e) Change	2011 Actual	(i)-(g) Change	2012 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Darlington NGS									
1	**TWh**	27.8	(1.3)	26.5	2.4	28.9	0.0	29.0	(0.6)	28.3
2	**Unit Capability Factor (%)**	90.3	(2.7)	87.6	7.6	93.9	1.3	95.2	(2.0)	93.2
3	**PO Days**	118.8	4.2	123.0	(62.7)	68.3	(8.0)	60.3	3.4	63.7
4	**FEPO Days**	0.0	13.9	13.9	(13.9)	0.0	0.0	0.0	0.0	0.0
5	**FLR (%)**	1.7	1.5	3.2	(2.6)	1.5	(0.9)	0.6	1.7	2.3
6	**FLR Days Equivalent**	22.5	20.2	42.7	(34.5)	20.9	(12.7)	8.2	24.1	32.3
	Pickering NGS									
7	**TWh**	20.4	(1.1)	19.2	0.4	22.0	(2.3)	19.7	1.0	20.7
8	**Unit Capability Factor (%)**	75.3	(3.6)	71.7	1.7	81.5	(8.1)	73.4	4.4	77.8
9	**PO Days**	436.0	(16.7)	419.3	(124.3)	304.0	(9.0)	295.0	57.3	352.3
10	**FEPO Days**	0.0	21.5	21.5	49.2	0.0	70.7	70.7	(44.5)	26.2
11	**FLR (%)**	6.0	3.3	9.3	2.3	5.4	6.2	11.6	(4.6)	7.0
12	**FLR Days Equivalent**	105.3	55.9	161.2	49.2	101.1	109.3	210.4	(81.5)	128.9
	Totals									
13	**Unit Capability Factor (%)**	83.3	(3.1)	80.2	4.9	88.1	(3.0)	85.1	(0.6)	84.5
14	**PO Days**	554.8	(12.5)	542.3	(187.0)	372.3	(17.0)	355.3	60.7	416.0
15	**FEPO Days**	0.0	35.4	35.4	35.3	0.0	70.7	70.7	(44.5)	26.2
16	**FLR (%)**	3.5	2.4	5.9	(0.6)	3.2	2.1	5.3	(1.0)	4.4
17	**FLR Days Equivalent**	127.8	76.1	203.9	14.7	122.0	96.6	218.6	(57.4)	161.2
18	**TWh**	48.2	(2.4)	45.8	2.8	50.9	(2.3)	48.6	0.4	49.0
19	**Forecast for Major Unforeseen Events**	2.0	(2.0)	0.0	0.0	0.5	(0.5)	0.0	0.0	0.0
20	**Total TWh**	46.2	(0.4)	45.8	2.8	50.4	(1.8)	48.6	0.4	49.0

Line No.	Prescribed Facility	2012 Board Approved	(c)-(a) Change	2012 Actual	(e)-(c) Change	2013 Budget	(g)-(e) Change	2014 Plan	(i)-(g) Change	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Darlington NGS									
21	**TWh**	29.0	(0.7)	28.3	(1.4)	26.9	1.5	28.4	(2.3)	26.1
22	**Unit Capability Factor (%)**	94.1	(0.9)	93.2	(4.4)	88.8	4.7	93.5	(7.2)	86.3
23	**PO Days**	65.5	(1.8)	63.7	80.7	144.4	(67.3)	77.1	110.9	188.0
24	**FEPO Days**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
25	**FLR (%)**	1.5	0.8	2.3	(0.8)	1.5	(0.3)	1.3	(0.3)	1.0
26	**FLR Days Equivalent**	21.0	11.3	32.3	(12.6)	19.7	(5.1)	14.6	(1.9)	12.7
	Pickering NGS									
27	**TWh**	23.0	(2.3)	20.7	0.4	21.1	0.2	21.3	0.6	21.9
28	**Unit Capability Factor (%)**	84.9	(7.1)	77.8	1.4	79.2	0.7	79.9	2.2	82.1
29	**PO Days**	247.0	105.3	352.3	(48.8)	303.5	(10.6)	292.9	(5.0)	287.9
30	**FEPO Days**	0.0	26.2	26.2	(26.2)	0.0	0.0	0.0	0.0	0.0
31	**FLR (%)**	4.3	2.7	7.0	1.1	8.1	(0.3)	7.8	(2.3)	5.5
32	**FLR Days Equivalent**	84.6	44.3	128.9	23.5	152.4	(5.4)	147.0	(42.5)	104.5
	Totals									
33	**Unit Capability Factor (%)**	89.8	(5.3)	84.5	(0.2)	84.3	3.3	87.6	(3.6)	84.0
34	**PO Days**	312.5	103.5	416.0	31.9	447.9	(77.9)	370.0	105.9	475.9
35	**FEPO Days**	0.0	26.2	26.2	(26.2)	0.0	0.0	0.0	0.0	0.0
36	**FLR (%)**	2.8	1.6	4.4	0.1	4.5	(0.4)	4.1	(1.0)	3.1
37	**FLR Days Equivalent**	105.6	55.6	161.2	10.9	172.1	(10.5)	161.6	(44.4)	117.2
38	**TWh**	52.0	(3.0)	49.0	(1.0)	48.0	1.7	49.7	(1.7)	48.0
39	**Forecast for Major Unforeseen Events**	0.5	(0.5)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
40	**Total TWh**	51.5	(2.5)	49.0	(1.0)	48.0	1.7	49.7	(1.7)	48.0

Table 1b
Comparison of Production Forecast - Nuclear

Line No.	Prescribed Facility	2008 Actual	(c)-(a) Change	2009 Actual	(c)-(e) Change	2009 Budget
		(a)	(b)	(c)	(d)	(e)
	Darlington NGS					
1	**TWh**	28.9	(2.9)	26.0	(0.5)	26.6
2	**Unit Capability Factor (%)**	94.5	(8.6)	85.9	(0.5)	86.5
3	**PO Days**	69.1	101.2	170.3	(1.4)	171.7
4	**FEPO Days**	0.0	11.9	11.9	11.9	0.0
5	**FLR (%)**	0.7	0.9	1.6	(0.4)	2.0
6	**FLR Days Equivalent**	9.9	11.0	20.9	(4.9)	25.8
	Pickering A NGS					
7	**TWh**	6.4	(0.7)	5.7	(1.6)	7.3
8	**Unit Capability Factor (%)**	71.8	(7.6)	64.2	(15.4)	79.5
9	**PO Days**	0.0	74.0	74.0	0.0	74.0
10	**FEPO Days**	1.1	31.4	32.5	32.5	0.0
11	**FLR (%)**	27.9	(3.3)	24.6	13.1	11.5
12	**FLR Days Equivalent**	203.1	(50.5)	152.6	77.2	75.4
	Pickering B NGS					
13	**TWh**	12.9	2.2	15.1	(1.0)	16.0
14	**Unit Capability Factor (%)**	71.4	12.6	84.0	(3.2)	87.2
15	**PO Days**	62.1	63.4	125.5	23.5	102.0
16	**FEPO Days**	18.5	9.2	27.7	27.7	0.0
17	**FLR (%)**	24.2	(18.3)	5.8	(0.4)	6.2
18	**FLR Days Equivalent**	333.2	(257.3)	75.9	(8.3)	84.2
	Totals					
19	**Unit Capability Factor (%)**	83.8	(1.9)	82.0	(3.7)	85.6
20	**PO Days**	131.2	238.6	369.8	22.1	347.7
21	**FEPO Days**	19.7	52.4	72.1	72.1	0.0
22	**FLR (%)**	12.3	(5.8)	6.4	1.6	4.8
23	**FLR Days Equivalent**	546.1	(296.7)	249.4	64.0	185.4
24	**Total TWh**	48.2	(1.4)	46.8	(3.1)	49.9
25	**Forecast for Major Unforeseen Events**	0.0	0.0	0.0	0.0	0.0
26	**Total TWh**	48.2	(1.4)	46.8	(3.1)	49.9

As part of the 2014 - 2016 Business Plan review process (see Ex A2-2-1), OPG's senior management directed generation planning staff to reassess the plan based on OPG's historical performance in which significant production forecast variances have occurred (i.e., actual generation has been lower than forecast over the past nine years including 2013). The reassessment revisited both outage scope along with the allowances, with the objective of establishing a more realistic and accurate nuclear production forecast for 2014 - 2015.

2.3.1.1 Pickering

The Pickering production forecast for 2014 and 2015 in the 2014 - 2016 Business Plan shows a 1.0 TWh reduction in generation compared to the 2013 - 2015 Business Plan.

Chart 6

Pickering NGS Plan over Plan Changes

Pickering NGS		**2014**	**2015**	**Total Variance**
Generation - TWH	2014-2016 Nuclear Business Plan	20.9	21.3	
	2013-2015 Nuclear Business Plan	21.3	21.9	
	Variance (BP2014-16 vs 2013-2015)	-0.4	-0.6	**-1.0**
FLR %	2014-2016 Nuclear Business Plan	7.8	5.5	
	2013-2015 Nuclear Business Plan	7.8	5.5	
	Variance (BP2014-16 vs 2013-2015)	0.0	0.0	**0.0**
Planned Outage Days	2014-2016 Nuclear Business Plan	327.9	339.5	
	2013-2015 Nuclear Business Plan	292.9	287.9	
	Variance (BP2014-16 vs 2013-2015)	35.0	51.6	**86.6**

Numbers may not add due to rounding

generation losses[1] during the test period reflect challenging targets. While any production forecast is subject to unplanned outcomes, OPG continues to be subject to unanticipated production disruptions due to events such as an unbudgeted planned outage in 2015 to replace PHT pump motors at Darlington. Smaller (albeit negative) production variances were achieved in 2014 and 2015 when compared to previous years, as shown on Chart 2.

Chart 2

OPG Nuclear Production Variance and Revenue Impact

Line No.		2008	2009	2010	2011	2012	2013	2014	2015	Average	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	OPG Application - TWh	51.4	49.9	-	48.9	50.0	-	48.5	46.1		
2	OEB Approved - TWh+	51.4	49.9	50.7	50.4	51.5	51.0	49.0	46.6		
3	Actual -TWh	48.2	46.8	45.8	48.6	49.0	44.7	48.1	44.5		
4	Variance (TWh) (line 3 - line 2)	-3.2	-3.1	-4.9	-1.8	-2.5	-6.3	-0.9	-2.1	-3.2	-24.7
5	Revenue Impact - $M#	-159.9	-154.9	-242.4	-87.3	-121.3	-305.7	-45.9	-114.3	-154.0	-1231.8

+ 2010 is the average of 2008 and 2009 Board Approved; 2013 is average of 2011 and 2012 Board Approved.
# At OEB-approved rates of $52.98/MWh for 2008-2010 less fuel cost, and $51.52/MWh for 2011-2013 less fuel cost.
For 2014, 10 months at OEB–approved rate of $51.52/MWh and 2 months at OEB approved rate of $59.29/MWh, less fuel cost (average $52.82/MWh).
For 2015, at OEB approved rate of $59.29/MWh less fuel cost

The test period production forecast takes into account the following:

- Darlington Refurbishment Program with Darlington Unit 2 being taken out of service in 2016, followed by Unit 3 in 2020, Unit 1 in 2021 (and Unit 4 in 2023). Each unit refurbishment project will take more than three years to complete. Two post-refurbishment mini-outages have been scheduled for Unit 2 to address equipment reliability issues that are expected to emerge post refurbishment. The need for these post-refurbishment outages is based on operating experience at other nuclear facilities that underwent major refurbishment. The first mini "warranty" outage of 55 days duration is scheduled for Unit 2 in 2020, within six months post refurbishment. The duration will allow sufficient time for anticipated equipment repair by the vendors. The second mini "warranty" outage of 31 days duration is scheduled for Unit 2 in 2021, within 18 months post-refurbishment. The shorter duration is due to an

[1] See Attachment 1 - Glossary of Outage and Generation Performance Term for definitions.

Actual Versus Planned Forecast By Operating Unit 2013-2020

Requested for 5.1-VECC-19 - OEB Rating Filing 2017-2021

Operating Unit	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan
Darlington Unit 1								
TWh	7.5	5.8	5.5	7.5	5.2	7.1	7.0	5.2
Unit Capability Factor (%)	98.5	75.7	72.4	99.0	69.6	93.6	92.9	69.7
PO Days (excludes Refurb)	0	77	72	0	108	20	23	108
Refurb PO Days	0	0	0	0	0	0	0	0
FEPO Days	0	0	2	0	0	0	0	0
FLR (%)	1.3	2.2	8.3	1.0	1.0	1.0	1.0	1.0
FLR Days Equivalent	4.6	6.1	23.9	3.7	2.6	3.4	3.4	2.6
Darlington Unit 2								
TWh	5.1	7.4	6.4	5.9	-0.2	-0.2	-0.2	4.7
Unit Capability Factor (%)	67.6	96.9	84.3	99.0	0.0	0.0	0.0	72.2
PO Days (excludes Refurb)	78	3	50	0	0	0	0	58
Refurb PO Days	0	0	0	78	365	365	365	45
FEPO Days	20	0	0	0	0	0	0	0
FLR (%)	7.1	2.2	2.0	1.0	0.0	0.0	0.0	12.0
FLR Days Equivalent	18.8	8.0	6.4	2.9	0.0	0.0	0.0	31.6
Darlington Unit 3								
TWh	7.3	7.5	5.0	7.1	7.0	5.3	7.4	0.8
Unit Capability Factor (%)	96.6	98.8	65.7	93.6	92.9	71.0	98.3	99.0
PO Days (excludes Refurb)	0.0	0.0	95.8	20.0	22.5	103.3	2.5	0.0
Refurb PO Days	0.0	0.0	0.0	0.0	0.0	0.0	0.0	321.0
FEPO Days	0.0	0.0	5.8	0.0	0.0	0.0	0.0	0.0
FLR (%)	3.4	1.2	8.6	1.0	1.0	1.0	1.0	1.0
FLR Days Equivalent	12.2	4.2	22.4	3.5	3.4	2.6	3.6	0.5
Darlington Unit 4								
TWh	5.2	7.3	6.5	5.6	7.0	7.1	5.4	7.0
Unit Capability Factor (%)	69.0	96.0	85.2	74.4	92.9	93.6	72.1	92.9
PO Days (excludes Refurb)	66.5	11.8	48.8	91.0	22.5	20.0	99.1	22.5
Refurb PO Days	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FEPO Days	20.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FLR (%)	9.3	0.6	1.5	1.0	1.0	1.0	1.0	1.0
FLR Days Equivalent	25.9	2.1	4.7	2.8	3.4	3.4	2.7	3.4
Pickering Unit 1								
TWh	2.0	3.9	2.6	3.8	1.8	3.7	2.7	3.8
Unit Capability Factor (%)	47.1	87.6	58.0	84.4	41.7	83.8	61.6	83.8
PO Days	0.0	0.0	128.4	33.7	204.9	43.0	128.5	43.0
FEPO Days	109.7	0.0	17.3	0.0	0.0	0.0	0.0	0.0
FLR (%)	32.2	12.4	2.5	7.0	5.0	5.0	5.0	5.0
FLR Days Equivalent	81.6	45.1	5.5	23.4	8.0	16.1	11.8	16.2
Pickering Unit 4								
TWh	3.9	2.8	4.3	2.9	3.7	2.6	3.7	2.3
Unit Capability Factor (%)	86.7	63.6	95.3	65.6	83.8	57.5	83.8	52.3
PO Days	20.0	85.3	0.0	107.8	43.0	144.1	43.0	164.5
FEPO Days	4.5	34.3	0.0	0.0	0.0	0.0	0.0	0.0
FLR (%)	6.9	5.3	4.7	7.0	5.0	5.0	5.0	5.0
FLR Days Equivalent	23.5	12.9	17.3	18.2	16.1	11.0	16.1	10.1
Pickering Unit 5								
TWh	2.6	4.3	2.9	4.3	2.3	4.2	2.3	4.3
Unit Capability Factor (%)	58.7	95.8	66.1	96.0	53.2	95.0	51.9	95.0
PO Days	87.8	0.0	105.9	0.0	160.7	0.0	165.6	0.0
FEPO Days	53.4	0.0	14.7	0.0	0.0	0.0	0.0	0.0
FLR (%)	1.8	4.1	0.5	4.0	5.0	5.0	5.0	5.0
FLR Days Equivalent	3.8	14.9	1.1	14.6	10.2	18.3	10.0	18.3
Pickering Unit 6								
TWh	3.0	4.0	3.0	4.3	2.7	4.2	2.1	4.3
Unit Capability Factor (%)	67.6	88.7	68.0	96.0	60.4	95.0	48.1	95.0
PO Days	113.0	0.0	102.4	0.0	133.0	0.0	180.1	0.0
FEPO Days	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FLR (%)	0.1	11.3	5.3	4.0	5.0	5.0	5.0	5.0
FLR Days Equivalent	0.3	41.3	13.8	14.6	11.6	18.3	9.2	18.3
Pickering Unit 7								
TWh	4.3	2.8	4.2	2.9	4.2	2.0	4.2	3.0

Unit Capability Factor (%)	95.4	62.2	93.3	65.2	95.0	44.6	95.0	68.4
PO Days	0.0	113.9	0.0	117.5	0.0	193.5	0.0	102.5
FEPO Days	0.0	7.5	8.5	0.0	0.0	0.0	0.0	0.0
FLR (%)	4.6	6.6	3.3	4.0	5.0	5.0	5.0	5.0
FLR Days Equivalent	16.7	16.2	11.7	9.9	18.3	8.6	18.3	13.2
Pickering Unit 8								
TWh	3.9	2.4	4.3	2.6	4.2	2.5	4.2	2.0
Unit Capability Factor (%)	86.8	53.8	95.5	58.6	95.0	55.9	95.0	46.0
PO Days	0.0	85.7	13.4	142.6	0.0	150.2	0.0	188.9
FEPO Days	0.0	13.6	0.0	0.0	0.0	0.0	0.0	0.0
FLR (%)	13.2	25.6	0.7	4.0	5.0	5.0	5.0	5.0
FLR Days Equivalent	48.0	67.7	2.3	8.9	18.3	10.7	18.3	8.9

expectation that the majority of scope required to be addressed post-refurbishment will be completed during the first post refurbishment mini-outage in 2020.

- Eight mini-outages of approximately 20 days duration at Darlington over the period 2016-2021 are required to replace the high risk PHT pump motors. There are 16 operating PHT pump motors (four per unit) at Darlington. Failure of any one of the operating motors will result in a forced outage and could result in an extended outage, depending on availability of spare motors. Recent experience at OPG and operational experience from other utilities shows the expected service life of PHT pump motors to be 25 to 30 years, i.e., the approximate current service life of the Darlington facility. Based on operating experience to-date, including an unbudgeted planned outage to replace a failed PHT pump motor in 2015, OPG has an expedited program underway to purchase new or refurbished PHT pump motors and spares (Project #73566/80144 as described in Ex. D2-1-3) and mini outages have been included in the generation plan for their installation over the next five years.
- Darlington forecast FLR of 1.0 per cent for 2016 through 2019, 4.2 per cent for 2020 and 3.0 per cent for 2021. The increase in FLR in 2020 and 2021 reflects the return to service of Darlington Unit 2 from its refurbishment outage and is consistent with industry operating experience. Based on industry operating experience, the Darlington Refurbishment Program forecasts a Unit FLR of 12 per cent in the year of return to service and the year immediately following, 6 per cent in year two post-refurbishment, 2 per cent in year three post-refurbishment, and 1 per cent in year four and beyond post-refurbishment for the refurbished unit.
- Pickering's annual FLR stabilizing at 5.0 per cent for the period 2016 through 2021 reflecting expectations of reduced volatility in performance as a result of equipment reliability and fuel handling improvement initiatives.
- Undertaking 637 incremental planned outage days in 2016-2020 to enable the completion of various work activities required for Pickering Extended Operations as well as restoring normal planned outages and durations in 2020. These additional planned outage days reduce generation by 7.5 TWh over the period 2016-2020.

Year		Outage	Unit Affected	Description	Outage Duration (days)	Forecast Production (TWh) Impact Due to Outage	Revenue Impact of Outage ($M)
2017	Pickering	P1711	Unit 1	Planned Outage	204.9	2.6	168.0
		P1742	Unit 4	Mid-Cycle Outage	43.0	0.5	35.2
		P1751	Unit 5	Planned Outage	160.7	2.0	132.0
		P1761	Unit 6	Planned Outage	133.0	1.7	109.2
		Total			**541.6**	**6.8**	**444.4**
	Darlington	D1711	Unit 1	Planned Outage	108.4	2.3	152.9
		DNRU2	Unit 2	Refurbishment Outage	365.0	7.8	514.8
		D1731-PD	Unit 3	Planned Derate	2.5	0.1	3.5
		D1732	Unit 3	PHT Pump Motor Outage	20.0	0.4	28.2
		D1741-PD	Unit 4	Planned Derate	2.5	0.1	3.5
		D1742	Unit 4	PHT Pump Motor Outage	20.0	0.4	28.2
		Total			**518.4**	**11.1**	**731.2**
Total 2017					**1,060.0**	**17.9**	**1,175.6**
2018	Pickering	P1812	Unit 1	Mid-Cycle Outage	43.0	0.5	39.1
		P1841	Unit 4	Planned Outage	144.1	1.8	131.2
		P1871	Unit 7	Planned Outage	193.5	2.4	176.4
		P1881	Unit 8	Planned Outage	150.2	1.9	136.9
		Total			**530.8**	**6.6**	**483.6**
	Darlington	D1811	Unit 1	PHT Pump Motor Outage	20.0	0.4	31.3
		DNRU2	Unit 2	Refurbishment Outage	365.0	7.8	571.4
		D1831	Unit 3	Planned Outage	103.3	2.2	161.7
		D1841	Unit 4	PHT Pump Motor Outage	20.0	0.4	31.3
		Total			**508.3**	**10.9**	**795.8**
Total 2018					**1,039.1**	**17.5**	**1,279.4**
2019	Pickering	P1911	Unit 1	Planned Outage	128.5	1.6	129.8
		P1942	Unit 4	Mid-Cycle Outage	43.0	0.5	43.4
		P1951	Unit 5	Planned Outage	165.6	2.1	167.6
		P1961	Unit 6	Planned Outage	180.1	2.2	182.3
		Total			**517.2**	**6.5**	**523.1**
	Darlington	D1911	Unit 1	PHT Pump Motor Outage	20.0	0.4	34.8
		D1912-PD	Unit 1	Planned Derate	2.5	0.1	4.3
		DNRU2	Unit 2	Refurbishment Outage	365.0	7.8	634.3
		P1931-PD	Unit 3	Planned Derate	2.5	0.1	4.3
		D1941	Unit 4	Planned Outage	99.1	2.1	172.2
		Total			**489.1**	**10.5**	**850.0**
Total 2019					**1,006.3**	**16.9**	**1,373.1**
2020	Pickering	P2012	Unit 1	Mid-Cycle Outage	43.0	0.5	48.2
		P2041	Unit 4	Planned Outage	164.5	2.0	184.4
		P2071	Unit 7	Planned Outage	102.5	1.3	115.1
		P2081	Unit 8	Planned Outage	188.9	2.4	212.2
		Total			**498.9**	**6.2**	**560.0**
	Darlington	D2011	Unit 1	Planned Outage	108.2	2.3	208.7
		DNRU2	Unit 2	Refurbishment Outage	45.0	1.0	86.8
		D2022-PD	Unit 2	Planned Derate	2.5	0.1	4.8
		D2021	Unit 2	Post Refurb Mini Outage	55.0	1.2	106.1
		DNRU3	Unit 3	Refurbishment Outage	321.0	6.9	619.2
		D2042-PD	Unit 4	Planned Derate	2.5	0.1	4.8
		D2041	Unit 4	PHT Pump Motor Outage	20.0	0.4	38.6
		Total			**554.2**	**8.6**	**773.6**
Total 2020					**1,053.1**	**14.8**	**1,333.5**
2021	Pickering	P2111	Unit 1	Planned Outage	150.5	1.9	187.3
		P2141	Unit 4	Vacuum Building Outage	30.0	0.4	37.3
		P2151	Unit 5	Planned Outage	179.7	2.2	224.1
		P2161	Unit 6	Planned Outage	112.6	1.4	140.4
		P2162	Unit 6	Vacuum Building Outage	30.0	0.4	37.4
		P2171	Unit 7	Vacuum Building Outage	30.0	0.4	37.4
		P2181	Unit 8	Vacuum Building Outage	30.0	0.4	37.4
		Total			**562.8**	**7.0**	**701.3**
	Darlington	DNRU1	Unit 1	Refurbishment Outage	200.0	4.3	428.3
		D2121	Unit 2	Post Refurb Mini Outage	31.2	0.7	66.8
		D2122-PD	Unit 2	Planned Derate	2.5	0.1	5.4
		DNRU3	Unit 3	Refurbishment Outage	365.0	7.8	781.6
		D2142-PD	Unit 4	Planned Derate	2.5	0.1	5.4
		D2141	Unit 4	PHT Pump Motor Outage	20.0	0.4	42.8
		Total			**621.2**	**13.3**	**1,330.2**
Total 2021					**1,184.0**	**20.3**	**2,031.5**

- OPG has retained the 0.5 TWh allowance for major unforeseen events approved by the OEB[2] in EB-2010-0008 and has included this allowance in its production forecast.

3.0 NUCLEAR PRODUCTION PLANNING PROCESS

3.1 Methodology

Nuclear facilities are designed as base load generators. OPG's annual nuclear production forecast is equal to the sum of the nuclear generating units' capacity multiplied by the number of hours in a year, less the number of hours for planned outages, forced production losses (i.e., unplanned outages and unplanned derates, as these terms are defined in Attachment 1) and corrections for sources of Generation losses (i.e., lake temperature, grid losses, consumption (station service) as defined in Attachment 1).

OPG's nuclear planning process has not changed since EB-2010-0008 and is focused on establishing annual planned outage schedules and on calculating variances to planned generation due to forced production losses. Outage durations are determined based on the scope of work defined for each outage while considering recent benchmarking efforts and the nuclear commitment to continuous improvement. The objective is to establish a realistic and accurate annual nuclear production forecast based on the Nuclear Generation and Outage Plan, with the following deliverables:

- A planned outage schedule for all stations that includes unit outage start dates, end dates, and durations, as well as a summary of major elements comprising the scope of work that will be executed during each outage.
- Operational reliability targets such as unit capability factor and the level of forced production losses represented by the forced loss rate ("FLR").
- Generation forecasts in terawatt-hours ("TWh") for individual nuclear units and an aggregated forecast for each station.

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[2] EB-2010-0008 Decision with Reasons, p. 39

objective is to establish a realistic and accurate annual nuclear production forecast based on the Nuclear Generation and Outage Plan[2], with the following deliverables:

- A planned outage schedule for all stations that includes unit outage start dates, end dates, and durations, as well as a summary of major elements comprising the scope of work that will be executed during each outage.
- Operational reliability targets such as Unit Capability Factor ("UCF") and the level of forced production losses aligned with the FLR.
- Generation forecasts (in TWh) for individual nuclear units and an aggregated forecast for each station.

The Nuclear Generation and Outage Plan is approved as part of the OPG business planning process. As discussed in Ex. F2-4-1, outage resource requirements and cost estimates for the outage OM&A budget are also tied to the Nuclear Generation and Outage Plan.

3.1.1 Planned Outage Schedule

OPG's planned outage schedule identifies the number of days required for inspections and maintenance activities to ensure continued safe, reliable and long-term operation. The planned outage scheduled is prepared in accordance with OPG's aging and life cycle management programs and in compliance with OPG's nuclear operating licenses issued by the Canadian Nuclear Safety Commission ("CNSC").

Planned outages are complex, involving many OPG divisions and individuals working together. Outages require focus, expertise, high levels of coordination and a level of detail that exceeds that of major construction projects (due to regulatory complexity and constraints in work execution). The planned outage schedule also incorporates "lessons learned" from recent OPG outages and operating experience outside of OPG.

Planned outages consist of a combination of "routine" inspection and maintenance activities and "non-routine" activities specific to a particular outage. Examples of routine activities are

[2] The Nuclear Generation and Outage Plan summarizes OPG nuclear generation and outage targets and is an input to the overall OPG Business Plan

preventive maintenance, feeder inspections and water lancing of steam generators. Non-routine activities include corrective and deficient maintenance, and replacements or modifications to the equipment or plant configuration that can only be done when the unit is shut down. The majority of work in an outage typically is routine preventive maintenance and inspection activities, while the remaining work is non-routine breakdown maintenance and modifications.

Planned outages must be submitted to and be "time-stamped" by the IESO. In most cases, OPG submits its nuclear outage schedule early in order to secure an early time-stamp date; this date determines the outage advanced approval priority in the IESO's outage queue. In addition to an advance approval process, all outages in the queue are subject to final approval by the IESO, which can deny this approval at any time up to the start of the outage.

For the test period, there are single unit planned outages for routine maintenance at Darlington each year from 2016 to 2021. In addition, the first outage for the Darlington Refurbishment Program will commence in October 2016 with Unit 2 being taken out of service. Unit 2 is scheduled to return to service in 2020. Unit 3 refurbishment is scheduled to begin in 2020 and Unit 1 refurbishment is scheduled to begin in 2021. There are two short post-refurbishment mini "warranty" outages scheduled for Unit 2 in 2020 and 2021 as described in section 2.0 above.

The six Pickering units are on a two year planned outage cycle for routine maintenance, meaning that three units are subject to planned outages each year. Therefore Pickering will be subject to three planned outages per year in the 2016 to 2020 period. In addition there is one mid-cycle planned outage ("mid cycle" meaning mid-way through the two year planned outage cycle for Pickering as discussed above) for Pickering Unit 1, or Unit 4 every year in the test period, to allow for additional preventive maintenance which will lessen the risk of forced outages on those units.

Observations – Rolling Average Unit Capability Factor (CANDU)

2013 (Rolling Average)

- Pickering performed below the median at both the plant and unit level.
- Pickering's gap to best quartile performance in Unit Capability Factor (UCF) was 16.26% for the rolling average period ending in 2013.
- Darlington performed above the industry median at the plant level (90.44 vs. 89.05). Overall Darlington's capacity factor dropped from 92.01 to 90.44 in 2013 however the industry median also dropped from 92.08 to 89.05.
- Darlington Unit 3 continued in the best quartile for the unit level comparison.
- Darlington's gap to best quartile performance in UCF was 1.6% for the rolling average period ending in 2013.

Trend

- 2013 was the best performing year (over the review period) for Pickering, and was slightly better than 2012 performance.
- Pickering's largest improvements came from Unit 4 and Unit 5. However, Unit 1 declined in 2013 compared to 2012.
- Industry median and top quartile declined slightly in 2013 compared with 2012, resulting in a narrower gap between Pickering and top quartile.
- Darlington's UCF has been trending up in the past several years prior to 2013. Darlington's UCF dropped in 2013 from 92.01 to 90.44.

Factors Contributing to Performance

- Equipment reliability, human performance and vendor quality issues have contributed to the gap between Pickering performance and industry median.
- Darlington and more so Pickering observed a higher number of planned outage days. The higher number of planned outage days contributes to a lower UCF compared to CANDU industry peers.
- Forced outages and forced extensions to planned outages have also negatively impacted the Capability Factor at Pickering and Darlington.
- Pickering has planned short mid-cycle outages to complete critical maintenance activities to improve the reliability of the plant. The mid-cycle outages allow for further backlog reduction and reliability improvements, with the intent to improve overall unit and station performance in the long term.

Observations – Rolling Average Unit Capability Factor (CANDU) (CONT'D)

- Pickering is executing an extensive list of high-priority work orders between 2012 and 2014 to improve reliability, and reduce operator burdens. To date over 2000 work orders have been executed of the planned 3000.
- Pickering has teams focused on reducing corrective and deficient work backlogs, and is focusing on preventing the inflow of emergent work through proactive equipment replacement, or minor modifications to improve design.
- Darlington planned outage days have been decreasing due to outage initiatives to reduce planned outage duration.
- Darlington had extensions to the two planned outages in 2013 as well as having five forced outages.
- Darlington is completing work that will improve plant reliability through system health reporting. Included in the Plant Reliability List are work orders to improve system health and work that is identified as 'operations critical work'.
- Through system health reporting, Darlington is implementing actions to reduce the incoming rate of critical corrective and deficient work orders. This is an effort to improve plant reliability as well as allow maintenance to complete preventative maintenance.

Board Staff Interrogatory #83

Issue Number: 5.1
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

Reference:
Ref: E2-1-1, page 4
OPG has stated that it expects Pickering's annual FLR to stabilize at 5% from 2016 through 2021. This was attributed to equipment reliability and fuel handling improvement initiatives.

a) Generally, what factors are considered in the assessment when forecasting the FLR and how is it calculated?

b) What are the specific factors, assumptions and experiences that have led to the expectation of an FLR of 5% over the 2016-2020 period for the Pickering units.

Response

a) Forced Loss Rate ("FLR") forecasts are developed by assessing a number of interlinked factors. As discussed at Ex. E2-1-1, pp. 8-9, these include:

- An assessment of the FLR historical trending performance
- An assessment of Equipment Reliability Index and Plant System Health, looking at historical trends and expected future equipment condition, including fuel handling equipment reliability.
- A review of maintenance backlogs, both historical trends and expected future performance
- An assessment of human performance, both historical trends and expected future performance.
- An assessment of capital and OM&A project investments, and the timing of specific project availability for service.
- Any known improvements or plant material condition issues.

The determination of FLR is described at Ex. E2-1-1 Attachment 1, p. 1.

b) The forecast of a 5% FLR for Pickering over the 2016 to 2020 period is based on the following assumptions:

- Pickering has continued to make investments in programs to improve equipment reliability and plant system health, including a multi-year trend of reducing backlogs. This included identifying and executing key reliability work orders over a multi-year period. Corrective maintenance backlogs are at a multi-year low for the station.

- Pickering has made improvements and intends to continue to improve in the area of human performance.

- OPG continues to make capital investments in Pickering, with a focus specifically on systems that have previously been associated with high production losses as well as components at end of life where there is increased risk of unforeseen failures. These include fuel handling equipment reliability improvements and replacements of motors and seals associated with the primary heat transport and shutdown cooling systems. Capital investments are assessed from a value for money perspective based on their cost versus their potential to reduce the risk of forced outages.

- Chart 4 from Ex. E2-1-1, p. 9 that is reproduced below shows Pickering's FLR averaged 8.5% over the period 2010 to 2015 due in particular to excellent performance in 2015. A forecast of 5.0% for Pickering FLR is consistent with Pickering's improving FLR trend.

Chart 4

Pickering Forced Loss Rate

	2010	2011	2012	2013	2014	2015	Avg
FLR (%)	9.3	11.6	7.0	9.7	10.7	2.9	8.5

Response

a) As explained in Exx N1-1-1, page 14 (2nd bullet), the 2013 Unit 4 planned outage was deferred from October 2013 to January, 2014. It was deferred because:

- Unit 4 outage activities were severely restricted due to the presence of a 350,000 Rem/h radioactive hot spot in the Boiler Room. Removal of the hot spot required additional time for the development of remote tooling that would not have been available in time for an October outage start. The hot spot was removed event free in January of this year.

- There were key work activities during the outage for which critical parts would not be available due to extended delivery times. The deferral of the outage allowed for a significant improvement in parts availability.

b) Each outage has unique requirements and scope to be completed during the planned outage period. The Unit 4 outage that was moved from 2013 has a planned duration of 85.3 days whereas the Unit 1 outage that was displaced from the fall of 2014 to the spring of 2015 has a planned duration of 78.3 days. The net effect of moving these two outages is an additional 7 days of work in 2014.

c)

i) This practice was included in the 2013 - 2015 Business Plan as there was one mid-cycle outage in 2013 and another in 2014. The additional mid-cycle outage in 2014 and in 2015 were added to address preventative maintenance concerns to reduce future forced outages, to achieve OPG's 2016 targeted improvement in FLR to 5.0%.

ii) No. However, OPG does not budget for forced outages.

iii) Planned outages are undertaken with the use of incremental resources whereas forced outages are typically managed using existing base resources. It is difficult to provide a specific answer as the nature of the issue which necessitated the forced outage will significantly influence the costs, specifically whether the issue can be corrected without the need for an injection of incremental resources.

iv) Yes, the compensation package is based on total generation which is impacted by forced loss rate and achieving planned outage schedule. Station management is also compensated on achieving or bettering FLR and PO targets.

d) The increase in the allowance for planned outages was less (more aggressive) than historical performance related to FEPO Days based on the business planning initiatives (i.e., Fuel Handling Reliability Project) that are expected to ensure OPG planned outages are completed on budget.

Chart 2

OPG Nuclear Production Variance and Revenue Impact

Chart 4; revised

OPG Nuclear Production Variances and Revenue Impact

	2008	2009	2010	2011	2012	2013	Average
Actual/Forecast -TWh (1)	48.2	46.8	45.8	48.6	49.0	48	
Board Approved -TWH (2)	51.4	49.9	50.7	50.4	51.5	51.0	
Variance -TWh	3.2	3.1	4.9	1.8	2.5	3.0	3.1
Revenue Impact - $M (3)	-159.9	-154.9	-242.4	-87.3	-121.3	-145.6	-151.9

(1) All amounts are actual with exception that 2013 is OPG Budget production forecast
(2) 2010 is average of 2008 and 2009 Board Approved; 2013 is average of 2011 and 2012 Board Approved
(3) Board Approved rates of $52.98/Mwh 2008-10 and $51.52/Mhw 2011-13 less fuel

The test period production forecast takes into account the following:

- Darlington will execute a Vacuum Building Outage (VBO) in 2015 in which all 4 units will be shutdown. The 2015 VBO eliminates a scheduled 4 unit shutdown Station Containment Outage (SCO) in 2015.
- A mid-cycle planned outage of 20 days on Pickering Units 1 in 2014 to focus on preventative maintenance and lessen the risk of future forced outages.
- An extended scope and duration for the planned outages at Pickering Units 5-8 as a result of the Pickering Continued Operations initiative (see Ex F2-2-3) equivalent to 0.5 TWh.
- Pickering's forecast FLR for 2014 is 7.8 per cent and 5.5 per cent in 2015. Pickering's FLR is trending lower (Pickering's actual FLR was 9.3 per cent in 2010, 11.6 per cent in 2011 and 7.0 per cent in 2012 as set out in Ex. E2-1-2, Table 1) reflecting expectations of improved performance due to reliability improvements.
- Darlington's forced loss rate (FLR) is 1.3 per cent in 2014 and 1.0 per cent in 2015.

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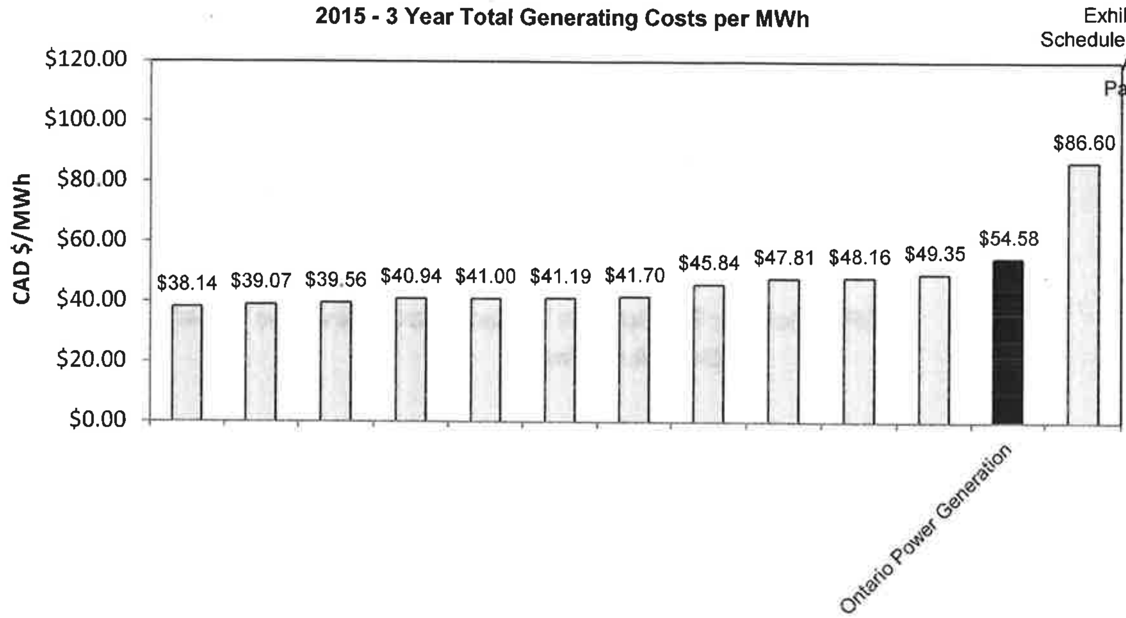
EB-2016-0152
Exhibit L, Tab 6.2
Schedule 15 SEC-063
Attachment 3
Page 93 of 107



*OPG plant values of 3-year rolling average TGC per MWh are shown below:

Unit	2015 3-Year TGC
Darlington	$44.38/MWh
Pickering	$67.36/MWh

Table 5: Three-Year Total Generating Cost per MWh Rankings

	2010	2011	2012	2013	2014	2015
	9	7	4	1	1	1
	4	4	5	4	4	2
	1	2	2	6	5	3
	3	1	1	2	2	4
	2	3	3	3	3	5
	10	8	7	7	6	6
	NA	NA	NA	11	7	7
	14	13	14	14	12	8
	5	5	6	5	8	9
	11	11	11	9	9	10
	7	9	9	10	11	11
Ontario Power Generation	12	12	10	8	10	12
	13	14	13	13	13	13
	8	10	12	12	NA	NA
	6	6	8	NA	NA	NA

Note: Two operators have been removed due to acquisitions by the other operators in the panel (reason for 14 ranked operators in 2010 vs. 13 in 2015).