K14.2

CME Compendium

Panel 3B

OPG 2017-2021 Rates – EB-2016-0152

Board Staff Interrogatory #106

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 3 page 12

ScottMadden states that, "The work management metrics (Scope Stability and Schedule Adherence) are relatively new for the industry. OPG benchmarks their performance against these metrics at a lower level in the organization ..."

Please provide the scope stability and schedule adherence benchmarked data for 2014 and any prior years for which the data are available.

Response

The following charts summarize OPG's performance for scope stability and schedule adherence from 2012-2014.

Chart 1: Scope stability

	2012				2013				2014			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
DN	83%	84%	80%	69%	84%	75%	72%	67%	61%	71%	61%	68%
PN	62%	55%	60%	54%	51%	53%	68%	56%	64%	63%	65%	62%

Top quartile for scope stability is benchmarked at 92%.

Chart 2: Schedule Adherence

	2012				2013				2014			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
DN	89%	90%	88%	88%	93%	88%	88%	88%	84%	86%	87%	88%
PN	89%	88%	87%	88%	85%	88%	88%	85%	86%	86%	86%	86%

For Schedule Adherence, OPG uses Schedule Completion to benchmark. Top quartile is benchmarked at 95%.

benchmark standards changed with Revision 3 of AP-928 Work Management Practices at INPO in June 2010. The new standard created an alignment between engineering criticality coding and backlog classification that allows improved focus on the more critical outstanding work. The new standard also sets a more consistent foundation for classification of backlogs such that comparisons between utilities will be more meaningful. All OPG sites converted to the new standard in January 2011 and therefore the 2012 report and subsequent reports, including 2014, reflect the new standard.

Other nuclear operators sometimes benchmark reliability metrics such as: (1) Refueling Outage/Fuel Reliability, (2) Scope Stability, and (3) Schedule Adherence. These metrics are not reported by OPG in the 2014 benchmarking report (nor were they recommended by ScottMadden in the 2009 report). Refueling outage metrics are not applicable to OPG because of CANDU technology, which allows for online refueling vs. offline. The work management metrics (Scope Stability and Schedule Adherence) are relatively new for the industry. OPG benchmarks their performance against these metrics at a lower level in the organization vs. in their top tier benchmarking report because the metrics are new, data is not yet consistently reported and there are limited historical trends.

OPG annually evaluates the need to potentially adjust or add new metrics. OPG looks for reliable, consistently reported metrics which allow for reasonable, longer term comparison and they also try to balance the number of top tier indicators they use for their benchmarking report (and thus for business planning) to avoid diluting their focus. Focusing on key top tier metrics is a standard industry practice. Scope Stability and Schedule Adherence may be added in the future as more reliable historic information is available.

Value for Money Metrics: The 2014 benchmark report contains four comparative performance metrics – all of which were included in the 2009 report. The comparative peer panel is the same.

Inventory values are sometimes used by other nuclear operators but are not currently utilized by OPG, though a benchmarking effort is presently underway. These metrics are not consistently reported by any of the nuclear oversight organizations (INPO, WANO, COG, CEA or EUCG) and so are not readily available, requiring a custom effort to produce. Thus, these are not metrics we would recommend annually refreshing today. They are often used for "second tier" analysis using smaller subsets of nuclear operators and have only recently become a focus.

Human Performance Metrics: The 2014 report contains one Human Performance Metric – the "18-Month Human Performance Error Rate." This is a relatively new metric designed and reported by INPO for 62 nuclear stations. Consistent data for this metric was not available in 2009 and was not included at that time.

Other metrics often used by nuclear operators in this area are: (1) Event Free Day Resets, (2) Training, and (3) Overtime. Unfortunately, there are no industry-wide accepted benchmarking data for these metrics. OPG uses these metrics for internal performance tracking but not for benchmarking due to limited data.

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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 –

SEC Interrogatory #43

Issue Number: 4.4
Issue: Are the proposed test period in-service additions for nuclear projects (excluding those for the Darlington Refurbishment Program) appropriate?

Interrogatory

Reference:
[D2/1/1, p.7]
Please provide further details regarding the following continuous improvement initiatives:

a. Centre of Excellence for project management

b. Collaborative Front End Planning

Response

a) In late 2015, Nuclear initiated a Project Excellence initiative to implement consistent and streamlined project management practices for all projects executed in Nuclear. Since that time, a number of sub-initiatives have been implemented, including:
   a. Rollout of a common project delivery model/gated process in Nuclear. All new projects in 2016 are following this process. The process established standards related to risk, schedule, and costing at each project gate. As a project progresses from one phase of a project to the next, e.g., from Definition to Execution, the project is assessed against the criteria established in the gated process to confirm that it is ready to proceed.
   b. In support of the common project delivery model/gated process, central estimating and risk expertise was put in place to support each project.
   c. Standard portfolio metrics and reports have been developed.
   d. A project manager development program has been put in place and a number of project managers have attended a 5-day training session.

In early 2016, senior OPG management initiated a Project Management Centre of Excellence with a goal to improve project outcomes across OPG. This initiative will leverage the work started in Nuclear.

A working team has been established to develop and recommend to a Project Excellence Steering Committee, strategies for establishing across all of OPG:

- A common, scalable project delivery model for all projects across all business units that focus on delivering projects safely, at the required quality, on time, and on budget, with all project goals achieved.

- A Project Management Centre of Excellence organization model where project management expertise, best practices, tools, processes, and lessons learned are available to all OPG projects.

Once the working team recommendations are accepted by the Project Excellence Steering Committee, an implementation plan will be developed. A Project Management Centre of Excellence is targeted to be fully operational in 2017.

b) Collaborative Front End Planning is the integration of OPG resources with contractor resources primarily in the engineering phase of a project to ensure OPG requirements are fully understood and to address contractor inquiries in a timely fashion. OPG has deployed its own resources in contractors' offices to work collaboratively on completing project designs and execution planning.

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.

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

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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

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- 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.

APPENDIX 5: Nuclear Financial Plan, Operational Targets, and Initiatives

Financial Plan

(in millions of dollars)	Actual 2015	Business Plan 2016	Business Plan 2017	Business Plan 2018	Projection 2019	Projection 2020	Projection 2021
OM&A							
Base	1,157	1,180	1,192	1,210	1,232	1,247	1,259
Outage Incremental	316	332	390	372	343	327	326
Project Portfolio	115	94	111	91	82	82	87
Pickering Continued Operations Enabling Costs	-	15	26	55	107	104	-
Darlington Refurbishment Project	2	1	42	14	4	48	20
Nuclear New Build	1	1	1	1	1	1	1
Total Nuclear OM&A	**1,591**	**1,624**	**1,762**	**1,744**	**1,769**	**1,809**	**1,693**
Capital							
Project Portfolio (including Spares and Minor Fixed Assets)*	315	353	279	258	282	278	199
Darlington Refurbishment Project (excluding Support Services)	681	1,189	1,063	1,094	951	833	1,170
Total Nuclear Capital	**996**	**1,542**	**1,342**	**1,352**	**1,234**	**1,111**	**1,369**
Provision Expenditures							
ONFA Funded	61	104	140	150	206	260	256
Internally Funded - Base	96	104	109	116	118	120	123
Internally Funded - Projects	40	39	39	40	40	40	40
Internally Funded - Darlington Refurbishment Waste Containers	6	56	32	43	30	33	26
Total Nuclear Provision Expenditures	**203**	**303**	**320**	**348**	**394**	**453**	**445**
Fuel Expense (Pickering and Darlington)	**244**	**261**	**220**	**222**	**233**	**228**	**213**

*In 2019, includes $15M related to the load of new fuel bundles into the refurbished Darlington Unit 2

Operational Targets

The key 2016-2018 targets for the Nuclear business unit are set out below. These targets are informed by the latest industry benchmarks and are designed to drive continuous performance improvement.

Metric	NPI Max	Industry Best Quartile	Pickering 2015 Actual	Pickering 2016 Annual Target	Pickering 2017 Annual Target	Pickering 2018 Annual Target	Darlington 2015 Actual	Darlington 2016[1] Annual Target	Darlington 2017[1] Annual Target	Darlington 2018[1] Annual Target
All Injury Rate (#/200k hrs worked)	N/A	0.66	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Collective Radiation Exposure (person-rem/unit)	80.00	42.25	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Unit Capability Factor (%)	92.0	89.4	79.4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	85.1	86.0
Forced Loss Rate (%)	1.00	1.03	2.89	5.00	5.00	5.00	4.86	[redacted]	[redacted]	[redacted]
On-line Corrective Maintenance Backlog (work orders/unit)	N/A	11	125	39	28	28	24	20	15	[redacted]
WANO NPI (Index)	N/A	92.9	68.5	72.3	71.1	71.1	83.7	87.3	84.3	[redacted]
Human Performance Error Rate	N/A	0.0020	0.0055	0.0030	0.0030	0.0030	0.0031	0.0030	0.0020	0.0020
Total Generating Cost per MWh[2]	N/A	$38.71	[redacted]	[redacted]	[redacted]	[redacted]	$52.40	$47.35	$47.85	$48.68

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

[2] 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. The non-normalized Darlington target for 2017 is $63.76/MWh and 2018 is $63.50/MWh.

	Green = Max NPI Points Achieved (if applicable) or Best Quartile Performance
	White = 2nd Quartile Performance
	Yellow = 3rd Quartile Performance
	Red = 4th Quartile Performance

(12)

Chart 4
Operational and FinancialTargets

Benchmarking Indicators	WANO Max NPI	Best Quartile+	Median Quartile+	Pickering – Annual Targets 2016	2017	2018	Darlington – Annual Targets 2016	2017	2018
Safety									
All Injury Rate (#/200k hours worked)		0.66	N/A	0.24	0.24	0.24	0.24	0.24	0.24
Industrial Safety Accident Rate (#/200k hours worked)	0.20	0.00	0.02	0.1	0.1	0.1	0.1	0.1	0.1
Collective Radiation Exposure (person-rem per unit)	80.00	42.25	61.60	111.5	126.9	137.3	65	87.8	72.1
Airborne Tritium Emissions (Curies) per Unit		1,014	2,410	2,333	2,333	2,333	1,014	1,014	1,014
Fuel Reliability (microcuries per gram)	0.000500	0.000001	0.000001	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005
Reactor Trip Rate (# per 7,000 hours)	0.50	0.00	0.05	0.5	0.5	0.5	0.5	0.5	0.5
Auxiliary Feedwater System Unavailability (#)	0.0200	0.0000	0.0015	0.02	0.02	0.02	0.02	0.02	0.02
Emergency AC Power Unavailability (#)	0.0250	0.0001	0.0024	0.025	0.025	0.025	0.025	0.025	0.025
High Pressure Safety Injection Unavailability (#)	0.020	0.00000	0.00003	0.02	0.02	0.02	0.02	0.02	0.02
Reliability									
WANO NPI (Index)		92.9	85.8	72.3	71.1	71.1	87.3	84.3	93
Forced Loss Rate (%)	1.00	1.03	1.29	5	5	5	1	1	1
Unit Capability Factor (%)	92.0	89.4	86.5	77.6	71.5	72	91.1	85.1	86
Chemistry Performance Indicator (Index)	1.01	1.00	1.00	1.03	1.03	1.03	1.01	1.01	1.01
On-line Deficient Critical and Non-Critical Mtce Backlog (work orders/unit)		159	212	196	196	196	175	159	150
On-Line Corrective Critical and Non-critical Mtce Backlog (work orders/unit)		11	20	55	28	28	20	15	10
Value for Money									
Normalized Total Generating Cost per MWh ($/Net MWh)++,^		41.78	48.15	N/A	N/A	N/A	48.09	48.16	47.68
Total Generating Cost per MWh ($/Net MWh)++,^		41.78	48.15	71.79	77.36	76.91	48.09	65.23	64.36
Normalized Non-Fuel Operating Cost per MWh ($/Net MWh)++		24.48	27.88	N/A	N/A	N/A	33.04	35.30	33.60
Non-Fuel Operating Cost per MWh ($/Net MWh)++		24.48	27.88	60.10	66.89	69.34	33.84	49.50	46.99
Fuel Cost per MWh ($/Net MWh)		8.72	9.49	5.78	6.00	6.02	5.41	5.54	5.53
Capital Cost per MW DER (k$/MW)^^		52.97	69.02	39.70	27.52	9.62	65.54	55.19	64.99
Human Performance									
Human Performance Error Rate (# per 10k ISAR hours)		0.0020	0.0040	0.003	0.003	0.003	0.003	0.002	0.002

+ Best Quartile and Median Quartile for Value for Money metrics are forecast 2018 (2014 actual 3-year rolling average escalated).

++ 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.

^ Targets for selected metrics presented in Appendix 5 to the 2016-2018 Business Plan document (Ex. A2-2-1 Attachment 1) represent initial estimates that were subsequently finalized based on updated cost allocations, as anticipated in footnote 2 in Appendix 5.

^^ Design Electrical Rating (DER)

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APPENDIX 4: Financial and Headcount Plan Information

Key Financial Metrics *(in millions of dollars unless otherwise noted)*	Actual 2015	Business Plan 2016	Business Plan 2017	Business Plan 2018	Projection 2019	Projection 2020	Projection 2021
Net Income Attributable to the Shareholder	402	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Net Income	417	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Earnings Before Tax	509	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Return on Equity*	4.0%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Nuclear Total Generating Cost per MWh** *($/MWh)*	66.3	63.7	74.8	73.0	73.3	76.1	75.1
Hydroelectric Total Generating Cost per MWh** *($/MWh)*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Enterprise Total Generating Cost per MWh** *($/MWh)*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
FFO / Total Debt Ratio (%) *(Minimum threshold of 9%)*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Debt / EBITDA Ratio (times) *(Maximum threshold of 5.5)*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
FFO Adjusted Interest Coverage Ratio* (times) *(Minimum threshold of 3)*	5.0	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Debt Ratio	35%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Net Cash from Operations	1,465	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Cash Balance at Year-End	464	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Debt at Year-End	5,697	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Return to Shareholder***	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
OM&A Expenses from Ongoing Operations	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Darlington Refurbishment Capital Expenditures	706	1,231	1,095	1,121	979	858	1,195
Darlington Refurbishment In-Service Additions	147	350	374	9	-	4,809	-
Capital Expenditures excluding Darlington Refurbishment	670	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
In-Service Additions excluding Darlington Refurbishment	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Nuclear Waste and [redacted] Provision Expenditures	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

* Calculated using the methodology per OPG's external financial filings

** Total Generating Cost (TGC) is calculated as: (OM&A expenses from ongoing operations + fuel and Gross Revenue Charge expenses for OPG-operated stations + sustaining capital expenditures)/OPG generation adjusted for surplus baseload generation losses. Nuclear TGC/MWh adjusted for lower production due to the Darlington refurbishment outages is: $63.3/MWh in 2017, $61.8/MWh in 2018, $64.9/MWh in 2019, $63.2/MWh in 2020 and $57.3/MWh in 2021. Hydroelectric TGC /MWh for 2015 is as estimated.

*** Calculated as: Net Income Attributable to Shareholder + Income Taxes + Gross Revenue Charge + Property Tax PILs

(14)

Regular Headcount by Business Unit*	Actual 2013	Actual 2014	Actual 2015	Business Plan 2016	2017	2018	Projection 2019	2020	2021
Nuclear Operations	5,668	5,491	5,297	5,400	5,448	5,432	5,367	5,267	5,202
Nuclear Projects	302	274	253	284	277	277	267	257	257
Hydro Thermal Operations	[redacted]								
Commercial Operations & Environment	169	180	165	180	175	174	166	165	165
[redacted]	[redacted]								
Total Operations	**7,984**	**7,501**	**7,171**	[redacted]					
Business and Administrative Services (Chief Information Officer, Real Estate, Supply Chain)	1,010	947	870	892	869	859	852	839	839
Finance	307	273	266	278	268	261	255	249	249
Assurance (incl. Nuclear Oversight)	58	57	53	57	57	57	57	57	56
People & Culture (incl. Centralized Training)	580	576	531	557	563	556	561	557	551
Corporate Office	91	86	77	84	83	83	82	81	81
Corporate Business Development	55	49	42	48	48	48	48	48	48
Total Support Services	**2,101**	**1,988**	**1,839**	**1,916**	**1,888**	**1,864**	**1,855**	**1,831**	**1,824**
Total Ongoing Operations	**10,085**	**9,489**	**9,010**	[redacted]					
Darlington Refurbishment Project	181	189	237	501	512	520	545	524	519
Total Regular Headcount	**10,266**	**9,678**	**9,247**	[redacted]					

* As reported/projected at each year-end; not restated for subsequent budget transfers between organizations

MS. CARMICHAEL: Again, on an operator summary --

MR. MILLAR: Right.

MS. CARMICHAEL: -- level they won't, because Pickering is such a big influence to that number, but total generating costs for Darlington, as you've seen, is in the green, and Pickering has managed T -- escalation over the eight years.

MR. MILLAR: Well, TGC for Darlington is not in the green currently.

MS. CARMICHAEL: Not currently, yes, you're right, but we believe that except for the 2015 issues around PHG pump motors and high cost of VBO and other factors we -- that doesn't reflect the steady state operations of Darlington, and we believe that Darlington has been a very good performer, and once it goes through the -- it's sort of end of first life issues, which are, you know, equipment issues, preparing and getting into refurb, going through refurb, we believe that it will come out, and that is our objective, is for it to come out as a top performing plant again.

MR. MILLAR: Is it your view that these numbers represent the continuous improvement that OPG targets?

MS. CARMICHAEL: I would say that, yes, if you look at Darlington it has continuously improved. It's been a top performer. WANO itself has said it was one of the best performing plants in the world. And Pickering, if you look at the absolute numbers, I would say, yes, there is a lot of continuous improvement embedded in those numbers.

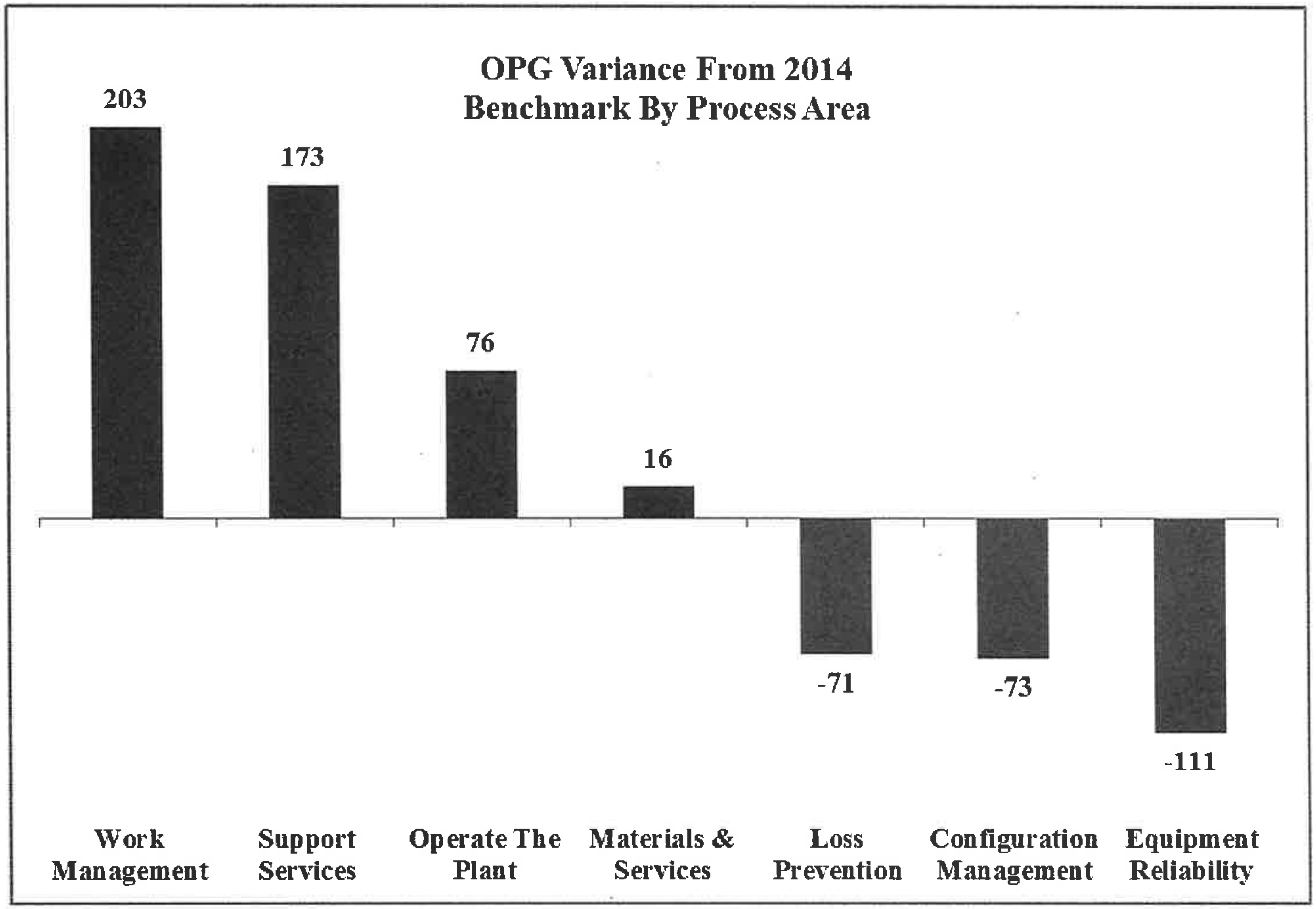
NUCLEAR OPERATIONS AND TOTAL FTE

	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

Work Management & Equipment Reliability Are The Process Areas With The Largest Variances



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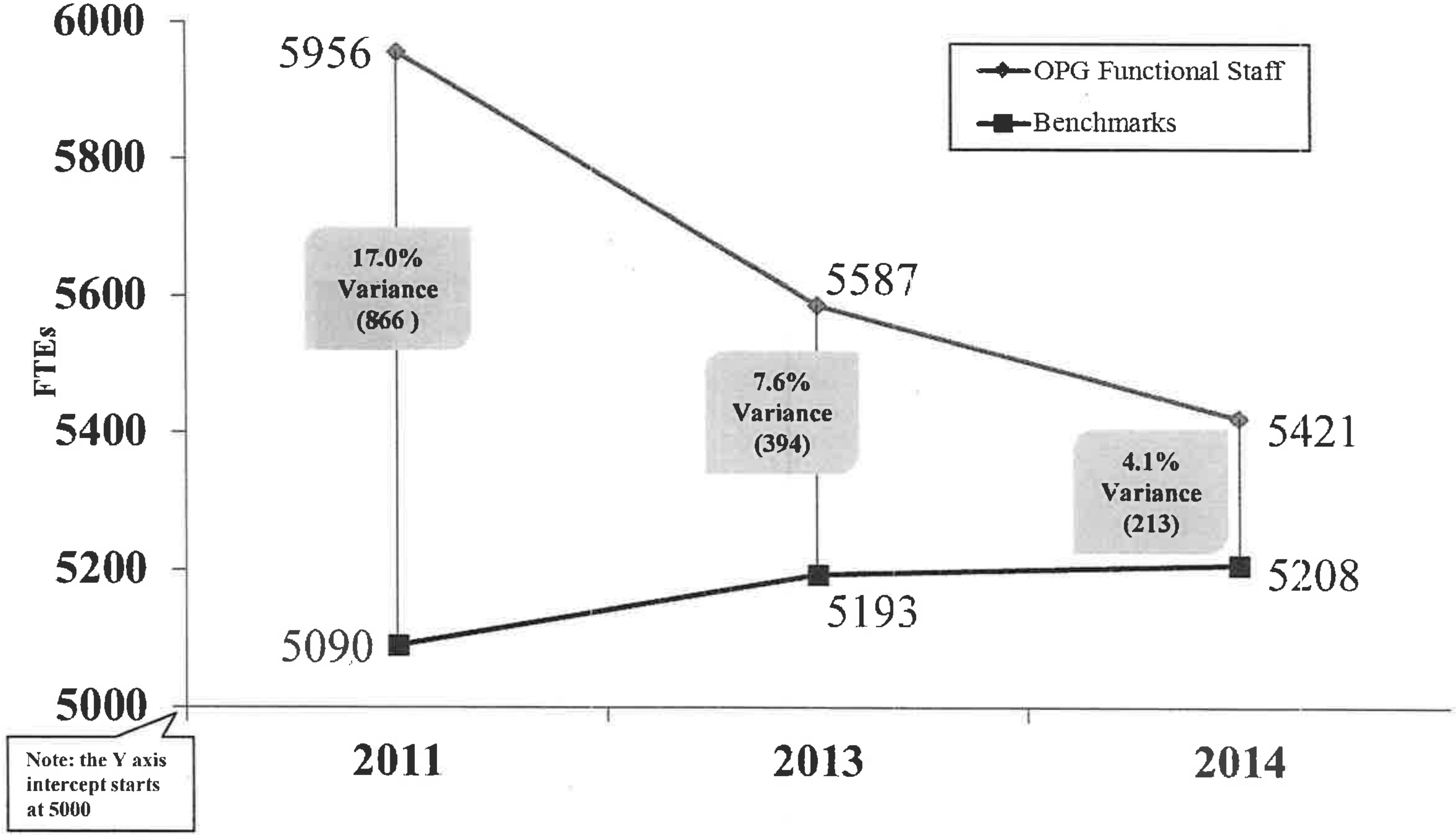
18

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.

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all part of purchased services.

MR. MILLAR: Okay. And those people would not show up at FTEs as well. That would be separate?

MS. CARMICHAEL: That is true. They would show up. They wouldn't show up as regulars or non-regulars, because non-regulars are temps.

MR. MILLAR: And if we look at line 6, we see there is a fairly significant increase in your purchased services cost, starting in about 2016 but extending through the test period? It's in the 160 to 190 million dollar range, something like that?

MS. CARMICHAEL: Yes, I see that.

MR. MILLAR: And that is a fairly material increase from at least up to 2015, where you were closer to 100, 108 in 2015?

MS. CARMICHAEL: So we see that as about a 20 million dollar increase. We -- the purchase service OM&A dollars are sort of reliant, I would say, on about 300 vendors that we have, more than maybe -- more than 300 vendors. And their costs fluctuate. They can be from anything from laundry services to rad protection technicians, any kind of work that needs to be done, and so we know that the escalation in the industry is higher than what we've escalated for over the period of our costs. And so we basically put an escalation in there to cover these costs associated with these 300 vendors.

MR. MILLAR: And then if we turn to page 83, this was a response to an AMPCO interrogatory. These are the and did their benchmarking report, is lower than the industry, which is about 5 percent for base OM&A programs.

MR. MILLAR: You said you did it on a ratio, if I understood you correctly. Even though your FTE numbers are going down slightly, your overtime actually goes slightly up in 2020 and '21. I mean, it's almost the same, but it's up a million or so from 2019.

So help me with how that works with the ratio approach? Maybe I just didn't understand you.

MS. CARMICHAEL: Well, our labour costs are going up too --

MR. MILLAR: Ah.

MS. CARMICHAEL: -- so labour -- overtime is always a factor of what people are getting paid, so if it's two times whatever or one-and-a-half times whatever, it's a ratio.

MR. MILLAR: Okay. So even though the FTE numbers are going down a little bit, the increases in compensation, I suppose, make up for that and then slightly more.

MS. FRAYER: Whatever the labour rate is, that's what makes the -- that's what the driver is.

MR. MILLAR: I have some questions for you about purchased services as well, which is also shown on this chart. And first, just so I understand, purchased services, is that essentially contracted labour? Is that what we're talking about there?

MS. CARMICHAEL: Yes, basically all the contracted labour, consultants, outsourced activity that we do, that's previously doing?

MS. CARMICHAEL: No, they would not be doing that. You can ask Ms. Donna Reese more about this, but our labour agreements do not basically allow to us do that. So we would not contract that kind of work out.

MR. MILLAR: Page 84, please, of the compendium. This is taken from your previous cost of service application, the 2013-0321. You'll see purchased services on line 6 and in your forecast for 2014 and 2015, they're both about 145, $146 million.

If we go back to page 81, your actual spend, you can see on line 6, was only 98 and 108 for 2015, so a significant under spend. What happened there?

MS. CARMICHAEL: So if I recall from when we did the plan originally, we did assume that we would be having attrition. So what we do is we do backfill temporarily for positions and work that needs to be done, and purchased services costs more than regular labour. So we had accounted for that need in that period.

Now, as we went through our actuals, we did see attrition, but we also saw more of an inability to actually get all that resources in on a timely basis, so we could hire those purchased services.

So it's a balance of timing again between attrition and trying to backfill with purchased services, temporarily backfill for that and so on.

MR. MILLAR: I thought you didn't contract for labour that FTEs would otherwise be doing?

behalf of Mr. Jaeger.

MR. MILLAR: And we see at the bottom, the bottom right, it looks like Mr. Mitchell here has written "agree" or "agreed". Does that look right to you?

MR. LAWRIE: It appears that way, yes.

MR. MILLAR: Okay. Does OPG in this hearing dispute that the OSB project was an example of poor performance?

MR. LAWRIE: I think its a an example where we could have done better in our risk management and estimating to report out what the true cost of the project should have been. As identified earlier, we went ahead and used a vendor estimate prior to the design being complete and we didn't provide sufficient contingency for that estimate given its level of completeness to rely upon. That was one of the primary drivers of the cost exceeding what was approved at the time for the work to execute.

MR. MILLAR: Do you agree with the assessment on this page that states this is poor performance?

MR. LAWRIE: Absolutely. As I said, our objective is to deliver projects for our committed cost and on schedule.

MR. MILLAR: Would you say the same for the auxiliary heating system?

MR. LAWRIE: Yes.

MR. MILLAR: In spite of this, I understand that OPG is seeking to recover its entire actual cost for both of these projects in rates. Is that right?

MR. LAWRIE: Yes.

MR. MILLAR: Why is that reasonable? If this is poor

And then the last sentence in that paragraph:

"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."

And I think you fairly said you accept these findings, but you've taken them and tried to learn from this report; is that fair?

MR. LAWRIE: Oh, absolutely. In fact, I can identify that the -- one of the risk managers that was involved in the refurbishment organization I've had the opportunity to join my organization, and in fact we're building upon these lessons learned and applying the same sort of rigour and robust risk management processes that are ingrained in the refurbishment program, so absolutely, very important for us.

I have to identify here that these are associated with a handful of new projects that we launched in the ESMSA. We have been executing a large number of projects. You can see in the evidence there's well over 150 projects, different sizes, and in general 60 to 70 percent of our projects do come in on or under budget in totality --

MR. MILLAR: Okay. But --

MR. LAWRIE: -- on the first release. But these two

Board Staff Interrogatory #24

Issue Number: 4.1
Issue: Do the costs associated with the nuclear projects that are subject to section 6(2)4 of O. Reg. 53/05 and proposed for recovery meet the requirements of that section?

Interrogatory

Reference:
Ref: Exh A1-6-1 Attachment 1

O. Reg. 53/05 requires that the OEB ensure that OPG recovers costs to increase the output of, refurbish or add operating capacity to a generation facility if the costs were prudently Incurred. In EB-2007-0905, OPG Payment Amounts April 1, 2008 to December 31, 2009, the OEB established the Capacity Refurbishment Variance Account (CRVA) to be used for this purpose.

Please identify which projects under OPG's Nuclear Operations capital forecast for 2016 to 2021 qualify for treatment under O. Reg. 53/05 and therefore for which the CRVA would be used.

Response

There are currently no projects under OPG's Nuclear Operations **capital** forecast for 2016 to 2021 which OPG believes qualify for treatment under O. Reg. 53/05 and therefore to which the Capacity Refurbishment Variance Account (CRVA) would apply.

OPG believes that Pickering Extended Operations enabling **non-capital** costs, including the Fuel Channel Life Assurance (FCLA) Project, qualify for CRVA treatment. Pickering Extended Operations are discussed in Ex. F2-2-3 and the FCLA business case is summarized at Ex. F2-3-3 Table 2b line 34. OPG also believes that the non-capital Fuel Channel Life Extension (FCLE) Project, including ongoing costs (see Full Release BCS attached to Ex. L-6.1-1 Staff-93), as well as the Fuel Channel Life Management (FCLM) Project continue to qualify for CRVA treatment.

The following table sets out the 2016-2021 forecasts for the above non-capital costs reflected in the evidence as well as the life-to-date actual amounts of these costs to the end of 2015:

OM&A Costs Subject to CRVA Treatment

	2015	2016	2017	2018	2019	2020	2021	Total
in millions								
Project OM&A								
FCLM Project	$ 2.3	$ 0.4						
FCLE Project***	$ 14.9	$ 15.4	$ 13.6	$ 14.4	$ 9.3	$ 1.7	$ -	$ 69.3
Ongoing	$ 1.0	$ 0.3	$ 8.0	$ 31.6	$ 57.6	$ 14.4	$ 7.5	$ 120.3
Less SFCR *					$ (24.0)			$ (24.0)
	$ 18.2	$ 16.1	$ 21.6	$ 46.0	$ 42.9	$ 16.1	$ 7.5	$ 168.3
PECO OM&A								
Enabling Costs **	$ -	$ 15.0	$ 25.6	$ 55.3	$ 107.1	$ 104.2	$ -	$ 307.1
	$ 18.2	$ 31.1	$ 47.2	$ 101.2	$ 150.0	$ 120.3	$ 7.5	$ 475.4

* Single Fuel Channel Replacement (SFCR) included in FCLE Project BCS as contingency/not included in revenue requirement but would be subject to CRVA if incurred

** Includes FCLA Project Costs

*** 2015 For FCLE is Life to Date.

Type 3 Business Case Summary

Part F: Qualitative Factors

The completion of the scope in the preferred alternative of this project is critical to the Continued and Extended Operations of Pickering, Refurbishment of Darlington. Since OPG operates the first CANDU units to be impacted by the fuel channel degradation mechanisms being investigated, our R&D findings may present financial opportunities when other CANDU units in the world are approaching their end-of-life.

Part G: Risk Assessment

Risk Class	Description of Risk	Risk Management Strategy	Post-Mitigation Probability	Post-Mitigation Impact
Cost	There is a risk that the CNSC may require additional BTs (beyond the 10 included in the scope) to validate the cohesive zone fracture toughness model	Mitigate – Contingency has been included for moderate scope addition	Medium	Medium
Scope	There is a risk that additional BT request by CNSC increase the project scope.	Mitigate – OPG, Bruce Power and vendors setup workshop with CNSC to demonstrate adequacy, reliability and repeatability of data obtained from the existing scope.	Medium	Medium
Resources	A delay in project schedule may occur due to unavailability of specialized resources that cannot easily be replaced. Reasons for unavailability could be due to emergent, spin-off work and conflicting priorities threatening the project schedule and cost.	Mitigate – Obtain resource commitment from vendors. Prioritize project work; communication and negotiation within business units regarding FCLCP commitments and support.	Low	Medium
Technical	There is a risk that results of R&D or field inspection may not support operations to the targeted fuel channel lives (235k EFPH for Darlington and 261k EFPH for Pickering)	Mitigate – Phased release strategy and continuous assessments of the R&D and inspection results to minize the cost of the project should this risk materialize	Medium	Medium
Schedule	There is a risk that technical complexity challenges the project team leading to delays in deliverables.	Mitigate – Identify challenges early through frequent Steereing Committee meetings.	High	Medium
Schedule	There is a risk that lab equipment breakdown jeopardize the timeliness of the tests or produce poor results.	Mitigate – Oversight on testing procedure and effective commissioning program. Vendor's inventory includes critical spare parts.	Low	Medium
Schedule	There is a risk that lengthy internal reviews effecting OPG milestones and CNSC submissions	Mitigate – Spread reviews across qualified OPG staff, monitor vendor's report status	High	High
Scope	There is a risk that discovery work, indeterminate results or unexpected results impact on the project scope.	Mitigate - Provide oversight on COG R&D work and prioritize according to CNSC commitments. Use allocated funds if required.	Medium	Medium
Scope	There is a risk that unexpected scope cuts from the outage causing insufficient data to perform FC fitness-for-service assessments.	Mitigate – provide input to MCED on scope change recommendations	Medium	Medium
Cost	There is a risk that one of the funding partners drops out of JP or decrease their contribution.	Mitigate – Early alignment with funding partners	Low	High
Technical	There is a risk that the end of life Heq is underpredicted due to higher D-ingress when fuel channels exceed the limit for	Mitigate – Conduct scrape samples and update	Medium	High

Board Staff Interrogatory #98

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 7

The evidence states, "For Pickering, a station-wide VBO is required every 11 years, with the most recent occurring in 2010 and the next scheduled for 2021. Pickering's outage OM&A expenditures in 2020 include costs for preparatory work for the 2021 VBO and the outage OM&A forecast in 2021 includes expenditures associated with a six unit VBO."

a) Please confirm that the outage OM&A expense for 2020 related to VBO would not be included in the forecast without the Pickering extended operations proposal.

b) If Pickering extended operations does not proceed, please confirm that the 2021 VBO would not be undertaken. Please confirm that the revenue requirement impact of any VBO costs underpinning payment amounts would then be credited to the capacity refurbishment variance account.

c) Please provide a table summarizing all the 2020 and 2021 VBO costs, including details for Pickering station and nuclear support division costs.

d) Are any of the costs set out in (b) also included in Exh F2-4-1 Chart 2, Pickering Extended Operations Outage OM&A?

e) Please provide the same table as set out in (b) for the Q2 2010 Pickering VBO. Please explain any differences in costs.

Response

a) Confirmed. For planning purposes, OPG assumed that the Vacuum Building outage as dictated by Canadian Safety Standards would not be required if operations were to cease in 2020.

b) As noted in part (a), if Pickering ends commercial operations in 2020, then OPG would seek approvals to not execute the VBO currently planned in 2021. As explained in Ex. L-05.1-1 Staff 87(c), the VBO is dictated by Canadian Safety Standards (CSA) N287.7 and undertaken pursuant to CNSC licence conditions. It is part of the normal periodic station inspection and testing activity.

AMPCO Interrogatory #112

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: F2-4-1 Table 1 Nuclear Outage OM&A

a) Please provide the number of FTEs allocated to each of the Nuclear Stations and the Nuclear Support Division categories for regular and non-regular staff for the years 2013 to 2021.

b) Please provide the labour and overtime costs separately allocated to each of the Stations and Support functions shown for regular and non-regular staff for the years 2013 to 2021.

Response

a) Please see the tables below.

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

b) Please see the tables below.

Outage OM&A Labour - Nuclear ($M)

Line No.	Regular Labour	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**	16.8	18.6	20.0	29.2	28.9	27.6	21.0	15.7	12.0
7	**Total Outage OM&A (F2-4-1 Table 2 & 3)**	16.8	18.6	20.0	29.2	28.9	27.6	21.0	15.7	12.0

Line No.	Non-Regular Labour	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	12.4	7.7	10.5	11.1	14.3	14.5	14.6	14.7	1.0
2	Pickering NGS	5.1	8.7	6.4	6.6	12.3	12.5	12.6	5.4	12.6
3	Pickering Continued Operations	0.4	0.2	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**	18.0	16.6	16.8	17.7	26.6	27.0	27.3	20.1	13.6
6	**Nuclear Support Divisions**	10.8	10.2	13.7	19.4	16.3	16.9	17.5	14.0	8.5
7	**Total Outage OM&A (F2-4-1 Table 2 & 3)**	28.7	26.8	30.5	37.1	42.9	43.9	44.8	34.1	22.1

Total Outage OM&A Labour	45.6	45.5	50.6	66.3	71.8	71.5	65.8	49.8	34.1

Outage OM&A Overtime - Nuclear ($M)

Line No.	Regular Overtime	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	23.9	10.8	14.1	11.6	15.8	16.5	15.6	17.2	3.3
2	Pickering NGS	23.1	18.1	17.8	17.3	18.0	18.0	17.1	5.8	7.0
3	Pickering Continued Operations	1.9	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	Not planned separately from PNGS				0.0
5	**Total Stations**	48.9	29.7	31.9	28.8	33.8	34.5	32.7	23.0	10.3
6	**Nuclear Support Divisions**	24.9	13.7	12.1	13.8	15.3	12.5	16.2	11.7	3.6
7	**Total Outage OM&A**	73.7	43.3	44.0	42.7	49.1	47.0	48.8	34.7	13.9

Line No.	Non-Regular Overtime	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	6.5	3.0	4.1	3.0	0.0	0.0	0.0	0.0	0.0
2	Pickering NGS	2.1	2.4	1.9	1.4	3.2	3.2	3.2	0.9	1.2
3	Pickering Continued Operations	0.2	0.1	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**	8.7	5.4	5.9	4.4	3.2	3.2	3.2	0.9	1.2
6	**Nuclear Support Divisions**	3.7	2.1	3.7	3.4	2.3	2.6	3.7	3.2	1.4
7	**Total Outage OM&A**	12.4	7.5	9.6	7.9	5.4	5.8	6.8	4.1	2.6

Total Outage OM&A Overtime (F2-4-1 Table 2 & 3)	86.2	50.8	53.7	50.5	54.5	52.8	55.6	38.8	16.5

Board Staff Interrogatory #102

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 10

OPG benchmarks value for money performance on a $/generating unit basis, which OPG states eliminates generation impacts due to extensive outage programs, reactor design and unit size. Was ScottMadden consulted in 2015 about this value for money metric, and if yes, what was their feedback?

Response

No, ScottMadden was not consulted in 2015 about the value for money metric on a $/generating unit basis.

However, the impact of unit size on plant cost performance was identified by ScottMadden in its 2009 Benchmarking Report, which states "Specific drivers of performance vary from station to station and will be discussed in more detail later in the report, but overall the biggest drivers are; capability factor, station size, CANDU technology, corporate cost allocation and potential controllable costs." (EB-2010-0008, Ex. F5-1-1, p. 123) The reference to station size was further defined as meaning "the combined effect of number of units and **size of units** [emphasis added]. The number of units and size of those units can have significant impacts on plant cost performance and review of the benchmarking data reveals a link between the two." (EB-2010-0008, Ex. F5-1-1, p. 124)

See also Ex. L-11.4-1 Staff-256.

- **Human Performance**
  OPG Nuclear's human performance strategy focuses on and reinforces the correct behaviors during all phases of station operations and maintenance. Pickering and Darlington improved their Human Performance Error Rate ("HPER") in 2014 compared to 2013 but remained in the fourth and third quartiles respectively due to improving industry benchmark performance.

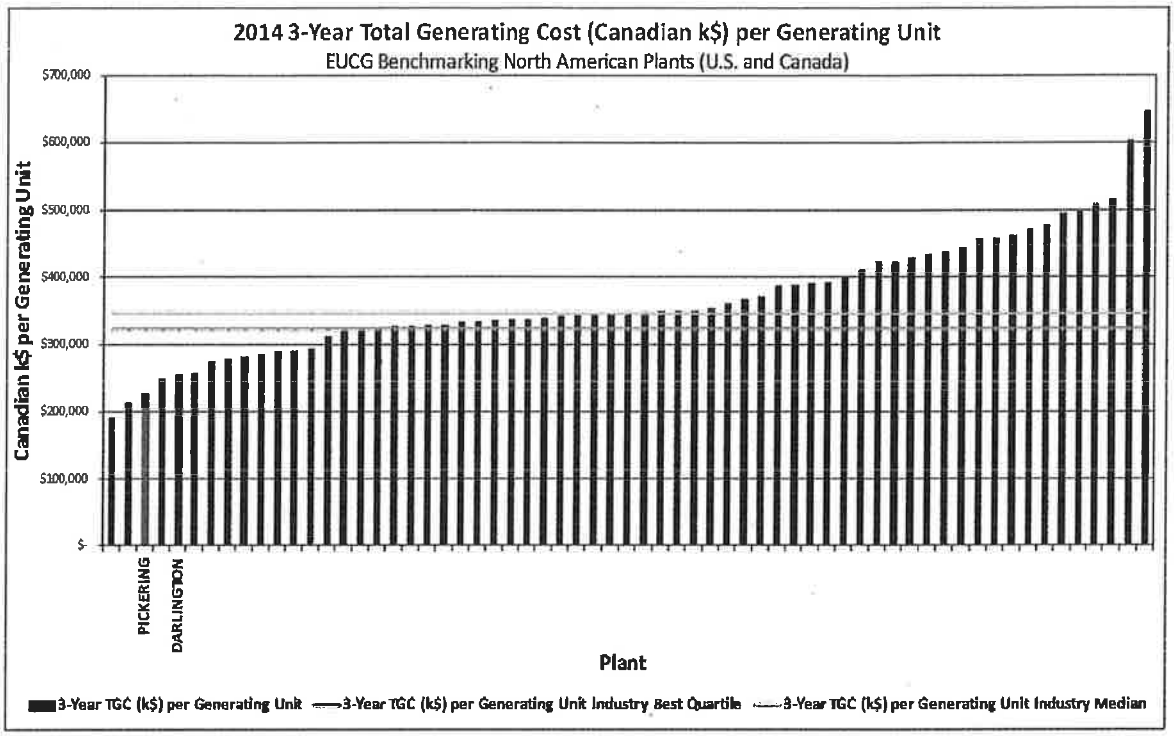
As noted above, OPG also benchmarks value for money performance on a $/generating unit basis in addition to $/MWh. The TGC/unit metric eliminates generation impacts due to extensive outage programs, reactor design and unit size. Chart 2 provides the value for money metrics on a per unit basis for 2014 with both Darlington and Pickering achieving best quartile performance for Total Generating Cost per unit.

Chart 2 – Plant Level Performance Summary

Metric	2014 Rolling Averages Best Quartile	Median	Pickering	Darlington
Value for Money				
3-Year Total Generating Cost per Generating Unit (Canadian k$ per Unit)	321,983	346,952	228,162	255,779
3-Year Non-Fuel Operating Cost per Generating Unit (Canadian k$ per Unit)	174,079	209,704	191,246	193,518
3-Year Fuel Cost per Generating Unit (Canadian k$ per Unit)	55,569	69,250	19,282	34,783
3-Year Capital Cost per Generating Unit (Canadian k$ per Unit)	50,331	59,478	17,634	27,478

Chart 3 shows that Darlington and Pickering are among the least expensive to operate on a per unit basis:

Chart 3



3.3 Gap-Based Business Planning – Nuclear Staffing Study

3.3.1 Overview

OPG continues to examine staffing levels as part of its benchmarking studies and anticipates that it will eliminate the Goodnight[4] staffing benchmark gap to industry peers in 2016.

The initial Goodnight study in 2011[5] indicated that OPG Nuclear was 17 per cent above its industry peers (normalized for CANDU technology differences), with a later update[6] by

[4] In its Decision with Reasons in EB-2010-0008, the OEB directed OPG to conduct an examination of staffing levels as part of its benchmarking studies for its next application. The OEB also noted that "OPG may wish to consider whether a study of the major cost differences between CANDU and PWR/BWR would facilitate the review of its application on the issue of cost differences between the various technologies." To satisfy this directive, OPG retained Goodnight Consulting Inc. ("Goodnight"), an external consultant with extensive experience in nuclear industry staff benchmarking, and filed a staff benchmarking study in EB-2013-0321. A detailed discussion of the methodology used for the initial study, and which continues to be used subject to industry data updates, can be found in EB-2013-0321, Ex. F2-1-1, section 3.3.

[5] February 2012 report filed as EB-2013-0321, Ex. F5-1-1 Part a.

[6] May 2013 report filed as EB-2013-0321, Ex. F5-1-1 Part b.