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

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projects did prove a challenge, were some of the first projects that we launched under the SMSA, and we did have an over-reliance on the vendor's proposal, given that the vendor's proposal for a target price, we felt that they had been incentivized through our performance fee model, which has incentives and disincentives for both cost and schedule performance, and we felt that they would be able to drive the behaviour of their organization to deliver, and we overestimated their ability to do that, so we've learned from that and we're putting the resources on it to manage those contractors.

MR. MILLAR: Okay. But with respect to the AHS project in particular, do you take issue with Modus's characterization of this as management failure?

MR. LAWRIE: I think it was more around the -- we had over-confidence in the vendor in proceeding with an estimate of $45 million before the design was completed, and portraying that as the total project cost when it wasn't a Class 3 estimate, it was a Class 5 estimate, and if we look at the project based on a Class 5 estimate it is coming in within the upper range of that estimate at around $100 million.

MR. MILLAR: At page 99 of the report it states -- not 99 of the report, 99 of the compendium. "The consequence to OPG", that's the consequence to OPG, "are two projects that may cause external stakeholders to question OPG's management prudence."

I guess here we are. So we're having that discussion

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MR. RUBENSTEIN: So when I look --

MR. LAWRIE: -- also -- and I've also identified that some of our projects that we first went out of the gate with in terms of using our new ESMSA contractor in around 2012, a number of years ago, they went forward in the business case in that first full release with an overstatement of the quality of cost estimate, and in fact if we take a look at some of those projects, they had very little expenditure on them before it went into a full release, and that's indicative of not having completed sufficient engineering to have a high confidence estimate, so they were more around the Class 5 level.

MR. RUBENSTEIN: So as I look at this -- and I have 11.72 when I add them all up -- that's a pretty significant amount that you're overspending on a total basis. Do you agree?

MR. LAWRIE: In terms of comparing it to the first execution BCS?

MR. RUBENSTEIN: Yes.

MR. LAWRIE: Yeah, there are some projects that are significantly over that amount.

MR. RUBENSTEIN: Well, on an overall basis, and that includes the overspends, the underspends, everything in between, I get about 11.72 percent. That seems significant to me.

MR. LAWRIE: Well, you also have to take a look at perspective of what an estimate is, and estimates that were used in those business cases had a certain class level, and

3. A Gating Process for AISC Portfolio Projects has not been formally implemented.		Moderate
A gating process is meant to define a clear list of requirements, deliverables, and expectations a project should follow in order to be granted approval to proceed to its next phase within the typical five phases of a project's life cycle.[3] In addition to the above, a robust gating process also requires that a project be defined and associated work scope be estimated to specified levels of accuracy. Although the AISC acts as a de facto Gate Review Board for AISC projects, the gating process outlined in the Nuclear Projects governance (N-STD-AS-0028) and Project Management Manual (N-MAN-00120-10001-GRB) has not been fully implemented for AISC projects. At present, the primary control used for gate approval between phases in the AISC project life cycle is the BCS process. While this is an important requirement, the BCS process does not constitute a complete list of all the deliverables required at each gate approval, nor formalize the challenge process that should take place regarding the approval of each deliverable. Management has indicated that they are in the process of formalizing a gating process for AISC projects in Q1 2016.		
Potential Causes & Impacts		
Potential Cause: The new Nuclear Projects governance and procedures are high-level principle-based documents which do not specifically address AISC requirements. Impact: Potential for cost increases and schedule delays due to insufficient independent oversight and control of project activities and objectives.		
Recommendations	**Management Action Plan**	**Owner & Target Completion Date**
Management should: • Complete its plans to develop and deploy a formal gating process for P&M use on AISC projects; • Ensure gate review documentation packages are created and maintained as a key part of the gate-approval process; and • Ensure that formal gate reviews and approvals are performed and that required stakeholders such as Finance are involved in the gate review and challenge process.	The Nuclear Projects Gated process will become the standard approach for P&M AISC projects beginning with 2016 Project New Starts. This change has been approved by the SVP/CNE and VP, P&M and an initiative is underway to align and implement the Gated process. Finance will be involved in the gate review process. Implementation requires the following actions: 1. Establish a common Gated process for all Nuclear Projects. 2. Through a Change Management Plan, prepare and issue desktop guides for Project Life Cycle to AISC Members and Project Managers. 3. Preparation and Issuance of AISC Terms of Reference to AISC Members and Project Managers.	Actions #1 and #2: Gary Rose VP Planning and Controls April 30, 2016 Action #3: Steve Woods SVP & CNE April 30, 2016

[3] The five standard phases in a project life-cycle are Identification, Initiation, Definition, Execution and Closeout.

I. Executive Summary

Burns & McDonnell Canada Ltd. and Modus Strategic Solutions Canada Company ("BMcD/Modus") provide the following Quarterly Report to the Nuclear Oversight Committee of the OPG Board of Directors ("NOC") regarding the status of the Darlington Nuclear Generating Station's Refurbishment Project ("Project" or "DR Project") as of April 30, 2014. The DR Project continues to advance toward its major goal of producing a Release Quality Estimate ("RQE") for final Board of Directors and Shareholder approval by October 15, 2015.

BMcD/Modus has continued to stress the importance for OPG to embrace its role as the integrator of the work and to actively manage the multiple contractors. To this end, the DR Team has made a significant shift in engineering strategy and will now directly manage and supervise the engineering service providers, rather than continuing the previous "hands-off" oversight approach. This is a bold but necessary move and one that is endorsed by BMcD/Modus. If OPG manages this transition well, we would expect a significant increase in engineering efficiency.

Pursuant to the Project's Assurance Plan approved by the Audit & Finance Committee, BMcD/Modus has prepared independent reports documenting the DR Team's status as well as further recommendations for improvement. This quarter we have issued Assurance Reports based upon our detailed review of: 1) DR Project Schedule Process and Development; 2) the 2013-2014 Business Plan as it relates to the latest project estimate (the "4c Estimate") and 3) Scope Status and Process. Upcoming reports will focus on our review of the Campus Plan cost and schedule overruns, 4d Cost Estimate vetting and RQE preparation. These full reports will be available for the NOC's review. In addition to our regular, everyday contact with the Project Team, we will continue to meet periodically with the Refurbishment Project Executive Team ("RPET") to discuss our reports to NOC and our Assurance Reports in order to clarify any recommendations and engage in discussion of appropriate actions. We are also coordinating our efforts with Internal Audit so that we meet our assurance commitments in an efficient and effective manner.

Much of our focus in this quarter's report was on evaluating the performance of the pre-requisite Facilities and Infrastructure projects ("F&I" or "Campus Plan Projects"). The Campus Plan Projects remain a significant risk to the Refurbishment Project, and provides important lessons learned for the DR Project.

The following is a brief summary of the DR Project's most significant developments over the last quarter:

- **Campus Plan Performance Project Risk:** Many of the Campus Plan Projects are forecasted to complete significantly beyond the approved budgets and schedules. In fact, schedule adherence is so poor that the Campus Plan work poses multiple threats to the start of Refurbishment. Over the last quarter, BMcD/Modus has engaged in a thorough review of several key Campus Plan projects in an attempt to identify trends and understand the causes of these cost and schedule overruns. Our findings show that the predominant cause was OPG's Projects & Modifications ("P&M") organization, who is managing this work for the DR Project, incorrectly applied an "oversight" project management approach for its EPC contracting strategy, leading to a series of cascading management failures and contractor performance issues, including misunderstandings of scope, uncontrolled scope creep, poor quality cost estimates, unrealistic and incorrect schedules and an inability to manage known risks, additional costs and delays. For multiple reasons described herein, P&M was completely overwhelmed in trying to manage Campus Plan Projects – in particular, the two largest of these projects, the D2O Storage Facility and Auxiliary Heat Steam Plant ("AHS") which were the "pilot" projects for this new contracting model.

  Simultaneous to our review, the P&M team's new leadership has taken aggressive action to correct as many of the major issues as possible. In acknowledgement of many of our recommendations and as a result of its own findings, P&M, the performing Extended Services Master Service Agreement ("ESMSA") contractors and the DR Team are developing more realistic project schedules for each scope of work that will account for need dates, available resources and optimal work flow. Senior management has committed to a full reforecast of the cost of each of the Campus Plan Projects, starting with the two most notable problem projects, the D2O Storage Facility

- 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.

SEC Interrogatory #45

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.8]
With respect to OPG's plan to improve project cost and schedule predictability:

a. Please explain provide further details regarding the plan to implement "a revised approval process for the Nuclear Operations project portfolio".

b. Please provide any documents outlining this new approval process.

c. Regarding OPG's improved plan for estimating project cost and schedules. Please provide an illustrative example of how a project would have previously been estimated, and how it would be estimated based on the proposed changes.

d. How much better does OPG expect it will improve initial estimates based on its improved plan?

Response

a) The Nuclear Operations project portfolio approval process is being supplemented by the implementation of a gated process. A gated process is a formal review of project readiness in terms of having completed sufficient project development to provide confidence in the project cost and schedule estimates for the next project phase of work.

b) See Ex. L-4.3-1 Staff-48 Attachment 20.

c) In the past, project initial cost estimates have been developed based on internal, third party, or contractor proposals with limited, if any, detailed engineering having been completed. These initial estimates lacked an understanding of engineering specific requirements and detailed stakeholder input which can significantly impact costs. With increased conceptual funding, more engineering work will be performed to develop the project scope and requirements that can be used as a basis for the initial project estimate. The use of updated estimating checklists and templates allows project lessons learned to be captured for future project managers developing project estimates.

AMPCO Interrogatory #17

Issue Number: 4.2
Issue: Are the proposed nuclear capital expenditures and/or financial commitments (excluding those for the Darlington Refurbishment Program) reasonable?

Interrogatory

Reference:
Ref: D2-1-3 Attachment 1 Page 2 Nuclear Business Case Summary Index

Please complete the attached excel spreadsheet prepared by AMPCO.

Response

In the attached spreadsheet (Attachment 1), the values for Original Total Project Estimate, except where noted, reflect the estimates in the first Execution Phase Business Case Summary ("BCS"). Per OPG-STD-0076 Developing and Documenting Business Cases, OPG does not commit to the full estimated cost of a project until the first Execution Phase BCS at which stage most of the detailed engineering and planning is complete and procurement of engineered equipment is underway.

For reference purposes, Chart 1 lists BCS' that have been filed as attachments in response to interrogatories.

Chart 1

Project No.	BCS Title	Interrogatory
25619	Operations Support Building Refurbishment	Ex. L-4.4-15 SEC-48 Attachment 1
33955	Shutdown System Computer Aging Management	Ex. L-4.4-15 SEC-46 Attachment 1
34000	Auxiliary Heating System	Ex. L-4.4-15 SEC-46 Attachment 2
31532	Powerhouse Water Air Conditioning Units Replacement	Ex. L-4.2-1 Staff-28 Attachment 1
82816	Vault Cooling Coil Replacement	Ex. L-4.2-1 Staff-40 Attachment 1
73566 80144	Primary Heat Transport Pump Motor Replacement/ Overhaul	Ex. L-4.2-1 Staff-41 Attachment 1
66600	Machine Delivered Scrape	Ex. L-4.2-1 Staff-43 Attachment 1

Witness Panel: Nuclear Operations and Projects

4.2-AMPCO-17
Ref: D2-1-3 Attachment 1 Page 2 Nuclear Operations Facility Tier 1 Projects (>$20 million)

Tab No.	Project No.	Business Case Summary (BCS) Title	Original In-service Date[4]	Updated In-service Date[5]	Original Total Project Estimate[4]	Total Project Estimate Last BCS	Total Project Estimate Current BCS[5]	Original OPG Project Management Estimate[4]	Updated OPG Project Management Estimate[5]	Original OPG Engineering Estimate[4]	Updated OPG Engineering Estimate[5]	Original OPG Procured Material Estimate[4]	Updated OPG Procured Material Estimate[5]	Original Contractor Estimate[4]	Updated Contractor Estimate[5]	Original Contingency[4]	Updated Contingency[5]
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)
1	25619	Operations Support Building Refurbishment	Oct-15	Oct-15	53.0	53.0	62.7	4.3	3.6	0.7	1.2	0.7	1.0	37.7	51.8	5.3	1.5
2	31412	DN Class II Uninterruptible Power Supply Replacement	Jun-19	Jun-25	38.4	55.1	55.1	3.9	4.0	0.9	1.9	13.3	0.0	[redacted]			
3	31508 49158 49299	Fukushima Phase 1 Beyond Design Basis Event Emergency Mitigation Equipment	Aug-16	Dec-17	70.0	111.0	115.6	6.2	8.9	5.0	9.4	2.9	0.1	[redacted]			
4	31717	Improve Maintenance Facilities at Darlington[2]	May-13	Oct-13	49.8	49.8	35.6	4.0	3.9	1.0	4.1	2.4	0.3	25.5	25.2	11.0	0.0
5	33621	Secondary Control Area Air Conditioning Unit Replacement[1]	Oct-14	Apr-17	12.3	19.1	28.3	2.5	6.3	3.2	1.7	2.1	2.6	[redacted]			
6	33631	Chiller Replacement to Reduce CFC Emissions	Jun-09	Dec-17	14.9	14.9	30.0	1.1	5.2	0.9	2.9	4.5	4.4	5.2	10.5	1.6	2.1
7	33819	Major Pump-sets Vibration Monitoring System Upgrades	Apr-17	Jul-21	12.8	12.8	23.0	3.9	2.0	0.0	1.1	0.1	0.1	[redacted]			
8	33955	Shutdown System Computer Aging Management[1]	Nov-16	Nov-15	17.2	20.3	20.4	3.1	3.0	7.1	5.0	1.9	1.8	1.3	7.5	1.8	0.0
9	33973	Standby Generator Controls Replacement[1]	Oct-13	May-17	21.8	39.6	43.5	4.5	8.3	2.8	3.2	8.0	7.7	[redacted]			
10	33977	Digital Control Computer Replacement / Refurbishment / Upgrades	Dec-10	Dec-18	22.1	22.1	24.9	1.2	2.0	4.6	7.1	3.2	1.9	[redacted]			
11	34000	Auxiliary Heating System	Dec-15	Oct-17	45.6	99.5	107.1	3.7	7.7	1.1	4.1	10.2	0.1	[redacted]			
12	36001	Primary Heat Transport Pump Motor Capital Spares	Apr-12	May-15	12.0	30.8	28.9	0.0	0.0	0.0	0.0	12.0	28.9	0.0	0.0	0.0	0.0
13	41023 49247	Unit 1 & 4 Fuel Channel East Pressure Tube Shift/Reconfigure	Jan-16	Mar-16	29.3	28.8	38.6	2.4	5.5	1.5	2.9	8.2	9.2	7.3	11.4	5.6	6.2
14	46634	Pickering A Fuel Handling Single Point of Vulnerability Equipment Reliability Improvement	Dec-12	Jun-18	27.0	27.0	27.3	2.4	3.6	1.0	2.1	6.0	4.7	[redacted]			
15	49109	PB Standby Generator Governor Upgrade[2]	Apr-08	Jan-15	22.1	23.3	22.8	0.9	0.9	2.0	2.0	5.9	6.6	9.7	10.4	1.7	0.0
16	49285	Modify/Replace Fiber Reinforced Plastic Components During 2010 Vacuum Buiding Outage[2]	Jun-10	Jun-10	12.8	24.5	17.7	1.8	1.0	1.3	0.5	1.6	2.3	5.5	13.7	1.9	1.8
17	62568	Feeder Repair by Weld Overlay	Jul-11	Deferred	53.2	53.2	0.0	0.8	0.8	0.3	0.3	3.3	3.3	[redacted]			
18	31518	Restore Emergency Service Water and Firewater Margins	Sep-16	TBD	47.1	47.1	47.1	5.0	5.0	1.5	1.5	7.3	7.3	[redacted]			
19	31524	Station Roofs Replacement		TBD	36.3	36.3	36.3	1.2	1.2	0.0	0.0	0.0	0.0	[redacted]			
20	31532	Powerhouse Water Air Conditioning Units Replacement[1]	Jan-23	Jan-23	26.6	26.6	26.6	0.9	0.9	1.3	1.3	0.0	0.0	[redacted]			
21	31535	Water Treatment Plant Replacement	Nov-16	Deferred	57.8	57.8	57.8	2.2	2.2	1.0	1.0	13.5	13.5	[redacted]			
22	31542	Transformer Multi-Gas Analyzer Installation	Dec-17	Mar-18	15.2	26.7	22.7	1.4	1.3	0.3	1.0	1.6	0.0	[redacted]			
23	31544	Radiation Detection Equipment Obsolescence[3]	Dec-21	Dec-22	46.9	46.9	46.9	1.1	1.1	0.6	0.6	23.8	23.8	[redacted]			
24	31552	Condenser Circulating Water and Low Pressure Service Water Travelling Screens Replacement	Nov-19	Jun-18	24.4	24.4	37.6	1.1	3.4	0.3	0.2	8.8	9.8	[redacted]			
25	31710	Shutdown Cooling Heat Exchanger Replacement	May-19	Sep-18	56.1	56.1	56.1	4.5	4.5	0.6	0.6	0.0	0.0	[redacted]			
26	31716	Neutron Over-Power & Ion Chamber Amplifier Replacement (Reactor Regulating System, Shutdown System 1 & Shutdown System 2)[3]	Jul-22	Jul-22	17.7	17.7	17.7	1.1	1.1	1.3	1.3	9.5	9.5	[redacted]			
27	38948	Zebra Mussel Mitigation Improvements	Jul-16	Aug-17	21.5	21.5	29.3	1.8	1.8	1.5	1.5	0.0	0.0	[redacted]			
28	73706	Holt Road Interchange Upgrade	Dec-15	Aug-16	31.0	31.0	24.6	0.0	0.0	0.0	0.0	0.0	0.0	[redacted]			
29	80022	OH180 Aging Management Hardware Installation[3]	Dec-22	Oct-22	47.2	47.2	47.2	2.3	2.3	5.7	5.7	22.3	22.3	[redacted]			
30	80078	Digital Control, Common Process and Sequence of Events Monitoring Computer Aging Management[3]	Jun-25	Jun-25	47.3	47.3	47.3	1.4	1.4	4.4	4.4	11.8	11.8	[redacted]			
31	80111	Generator Stator Core Spare	Jul-19	Jul-19	35.0	35.0	35.0	0.0	0.0	0.0	0.0	32.0	32.0	[redacted]			
32	82816	Vault Cooling Coil Replacement[1]	Jul-20	Sep-20	26.3	26.3	18.8	0.8	0.1	0.4	0.3	4.9	4.0	[redacted]			
33	73566 80144	Primary Heat Transport Pump Motor Replacement/Overhaul	Jun-22	Dec-19	129.5	129.5	124.0	9.9	6.9	2.2	1.2	3.4	31.0	[redacted]			
34	40976	Pickering B Fuel Handling Reliability Modifications[1]	Dec-15	Dec-18	29.0	37.3	43.0	1.2	2.4	0.9	0.8	9.1	8.7	[redacted]			
35	41027 32202	Fukushima Phase 2 Beyond Design Basis Event Emergency Mitigation Equipment	Dec-17	Dec-17	74.3	74.3	75.5	3.1	3.9	4.4	4.0	0.0	0.0	[redacted]			
36	66600	Machine Delivered Scrape	Jun-17	Jun-17	24.9	24.9	26.1	1.6	1.5	1.6	2.3	14.2	17.7	[redacted]			

Notes:
1. Current values reflect the amounts in the BCS approved subsequent to the filing.
2. Current values reflect the amouns in the Project Closure Report
3. Original and Current values reflect amounts in the Defintion Phase BCS and do not reflect committed values.
4. Original values reflect the amounts in the First Execution Phase BCS, except where noted.
5. Updated values reflect the current BCS, except where noted.

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%.

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

Observations – On-line Deficient Maintenance Backlog

2013

- The data in this panel was gathered by an independent industry peer group, the INPO AP-928 group.
- The last backlog benchmark was taken on December 31, 2013 and this observation utilizes this data.
- This review was performed using Revision 3 of INPO AP-928 Work Management Practices (effective June 2010).The industry best quartile and median thresholds were 209 and 280 work orders per unit respectively for On-line Deficient Maintenance Backlogs.
  - Darlington is performing above best quartile at 184 work orders/unit.
  - Pickering is performing near the best quartile threshold at 215 work orders/unit.

Trend

- In comparison to the 2012 benchmarking data:
  - Darlington has had improved performance (from 203 to 184 work orders/unit).
  - Pickering has had improved performance (from 232 to 215 work orders/unit).
- Darlington and Pickering have shown improvements in reducing backlogs since 2011. Trending prior to 2011 is not practical due to the change in benchmarking criteria (revision 3 of INPO AP-928 in June 2010).

Factors Contributing to Performance

- For Darlington and Pickering, factors that impact improvement of deficient maintenance backlogs include the following:
  - Forced outages and forced outage extensions, negatively affected backlog reduction efforts.
  - Gaps in the work package preparation and walkdown processes (for example: incomplete inventory parts staging, work protection not applied, and scaffolding not installed) contribute to delays in execution of backlog work orders.

Darlington

- Darlington performance is currently within best quartile (184 deficient work orders/unit). This is a 9.4% reduction in backlogs compared to 2012. To support continuous improvement with this metric:
  - Additional resources (Fix-It-Now team) are being dedicated to reduce the backlog by addressing emergent issues.
  - Increased emphasis on reducing long standing work orders (high average age).
  - Short-term actions planned for Work Management and Maintenance work execution based on the "INPO Cumulative Impact" document are in progress and will continue beyond 2014.

Pickering

- Pickering performed near the best quartile (209 work orders/unit) with 215 work orders/unit. This is a 7.3% reduction in backlogs compared to 2012. To support improvement:
  - The ongoing 3K3 initiative is a program to complete high priority work that improves station reliability, incoming work, and backlog reduction.
  - Additional resources (Fix-It-Now team) are being dedicated to reduce the backlog by addressing emergent issues.
  - Short-term actions planned for Work Management and Maintenance work execution based on the "INPO Cumulative Impact" document are in progress and will continue beyond 2014.

Filed: 2017-02-10
EB-2016-0152
Exhibit L, Tab 6.2
Schedule 15 SEC-063
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Observations – On-Line Deficient Maintenance Backlog (AP-928 Working Group)

2015 (Annual Value)

- The industry Best Quartile and Median Thresholds were 116 and 160 work orders per unit respectively for On-Line Deficient Maintenance (DM) backlog.
  - Darlington DM backlogs were at 174 Work Orders per unit for 2015 which is third quartile performance.
  - Pickering DM backlogs were at 251 Work Orders per unit which is fourth quartile performance.

Trend

- In comparison to the 2014 data:
  - Darlington performance in 2015 has improved from 176 to 174 work orders per unit
  - Pickering performance in 2015 improved from 276 to 251 work orders per unit
- Darlington has shown backlog improvement from 2011 through 2015.
- Pickering has shown backlog improvement from 2011-2013, a decline in 2014 and improvement again in 2015.

Factors Contributing to Performance

- For Darlington and Pickering the factors that impact the deficient maintenance backlogs include the following:
  - Forced outages and outage extensions which negatively impact the backlog reduction efforts by reducing the resources available to perform the planned work.
  - Gaps in the work package preparation, scheduling and parts availability
- To improve performance there is a fleet wide initiative to improve parts availability, which involves adherence to the work management process, reduction in the amount of work removed from the schedule and improvements to the process for in-house repair of components removed from systems. Implementation is ongoing and initiative completion is targeted for 2017.
- In addition to the fleet wide initiatives, both stations have made improvements to the Fix-It-Now teams to improve work execution efficiency and better address emergent work.

Observations – On-line Corrective Maintenance Backlog

2013

- The data in this panel was gathered by an independent industry peer group, the INPO AP-928 group.
- The last backlog benchmark was on December 31, 2013 and this observation utilizes that data.
- This review was performed using Revision 3 of INPO AP-928 Work Management Practices (effective June 2010). Based on this standard, the industry best quartile and median thresholds were 17 and 30 work orders/unit respectively for On-line Corrective Maintenance Backlogs.
    - Darlington is performing near the median threshold at 32 work orders/unit.
    - Pickering is performing below median at 124 work orders/unit.

Trend

- In comparison to the 2012 benchmarking data:
    - Darlington has improved performance (from 66 to 32 work orders/unit).
    - Pickering has slightly worsened since 2012 (from 118 to 124 work orders/unit).
- Darlington and Pickering are showing an improving trend since 2011, with Darlington having significant improvement and Pickering having less improvement. Trending prior to 2011 is not practical due to the change in benchmarking criteria (revision 3 of INPO AP-928 in June 2010).

Factors Contributing to Performance

- For Darlington and Pickering, the factors that impact improvement of corrective maintenance backlogs include the following:
    - Forced outages and forced outage extensions, negatively affected backlog reduction efforts.
    - Gaps in the work package preparation and walkdown processes (for example: incomplete inventory parts staging, work protection not applied, and scaffolding not installed) contribute to delays in execution of backlog work orders.

Darlington

- Darlington is currently near the median threshold (32 corrective work orders/unit). This is significant improvement from 2012 and reduction by over half of the number of backlogs. On-going initiatives to support improvement with corrective maintenance backlogs include:
    - Increased emphasis on backlog items with high age.
    - Short-term actions planned for Work Management and Maintenance work execution based on the "INPO Cumulative Impact" document are in progress and will continue beyond 2014.

Pickering

- Pickering is currently below median (124 corrective work orders/unit) and performance in this metric has degraded by from 2012. On-going initiatives to support performance improvement with corrective maintenance backlogs include:
    - Effectiveness and efficiency of Fix-It-Now teams will reduce corrective backlog work.
    - Short-term actions planned for Work Management and Maintenance work execution based on the "INPO Cumulative Impact" document are in progress and will continue beyond 2014.
    - The ongoing 3K3 initiative is a program to complete high priority work that improves station reliability, incoming work, and backlog reduction.

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Exhibit L, Tab 6.2
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Observations – 1 Year On-line Corrective Maintenance Backlog (AP-928 Working Group)

2015 (Annual Value)

- The industry Best Quartile and Median thresholds were 7 and 15 work orders per unit respectively for On-line Corrective Maintenance (CM) backlog.
  - Darlington CM backlogs were at 24 Work Orders per unit for 2015, which is in the third quartile.
  - Pickering CM backlogs were at 125 Work Orders per unit, which is in the worst quartile.

Trend

- In comparison to the 2014 data:
  - Darlington performance in 2015 declined from 20 to 24 work orders per unit
  - Pickering performance in 2015 improved from 160 to 125 work orders per unit
- Darlington has shown backlog improvement from 2011 through 2014.
- Pickering has shown backlog improvement from 2011-2012 and declined in 2013-2014.

Factors Contributing to Performance

- Refer to the factors contributing to performance discussed above in the 1 Year On-line Deficient Maintenance Backlog.

CCC Interrogatory #27

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:
Reference: Ex. F2/T1/S1/p. 14

The evidence states that the Chief Nuclear Office (CNO) in consultation with OPG's Nuclear Executive Committee (NEC) provided direction on top-down performance targets for each nuclear station for the business planning period. Please provide all of the documents related to this direction.

Response

The 2016-2018 Business Planning Instructions Memo (see Ex. A2-2-1 Attachment 2) provided direction for the business planning period. Corresponding top-down performance targets are provided for the 2016-2018 period, as per Attachment 1.

Summary Benchmark Table

Preliminary Benchmarking Results and Business Plan Targets

Metric	NPI Max	2014-Q4 Results (Rolling Average) Best Quartile	Median	Third Quartile	Pickering	Darlington	2015 BP Targets (Annual) Pickering	Darlington	2016 BP Targets (Annual) Pickering	Darlington	2017 BP Targets (Annual) Pickering	Darlington	2018 Targets (Annual) Pickering	Darlington	Notes
Safety															
All Injury Rate (#/200k hours worked)[1]		0.69	N/A	N/A	0.22	0.31	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69	Target set based on industry best quartile of 0.69.
Rolling Average Industrial Safety Accident Rate (#/200k hours worked)	0.20	0.00	0.02	0.06	0.03	0.06	0.15	0.15	~~0.15~~ 0.10	~~0.15~~ 0.10	~~0.15~~ 0.10	~~0.15~~ 0.10	0.10	0.10	Targets set to align to industry INPO goal of 0.10 for station operation and refurbishment.
Rolling Average Collective Radiation Exposure (Person-rem per unit)	80.00	42.25	61.60	78.94	[illegible]	69.06	[illegible]	73.80	[illegible]	56.00	[illegible]	77.60	[illegible]	71.50	2018 target set to maintain fourth quartile at Pickering and best quartile at Darlington. PN: Potential impact of 4 Rem to 2018 target is dependent on deferral of SFCR from P1561 to P1671. DN: 2016-2018 targets set to achieve maximum NPI points. 2016-18 CRE targets reflect dose for operating units only (excludes Unit 2 while in refurbishment).
Airborne Tritium Emissions (Curies) per Unit[2]		1,014	2,410	3,703	2,390	1,831	2,410	1,200	~~2,000~~ 2,333	~~1,000~~ 1,119	~~1,950~~ 2,333	~~1,000~~ 1,165	2,333	1,297	2018 target set to maintain second quartile at Pickering and Darlington. PN: Target at Pickering raised to 2,333 curies/unit for 2016-2018 but remains second quartile. Increase is attributed to higher likelihood of leaking equipment as station ages, potentially fewer resources and funding to tackle the issues and unavailability of TRF to maintain source term reductions. DN: 2016-2018 targets reflect emissions for 3 operating units (including TRF and U0) and excludes U2 from Oct 2016 onwards. Report card target split for DN and NR are draft and will be finalized during 2016 BP. Increases in 2016 and 2017 reflect impact of moderator drains (D1641), D2 defueling as well as D2O treatment and storage during refurbishment. Higher emissions per unit reflect U2 emission exclusions and higher station targets from TRF outage.
Fuel Reliability (microcuries per gram)	0.000500	0.000001	0.000001	0.000158	[illegible] ⇩	0.000158 ⇧	0.000500	0.000500	0.000500	0.000500	0.000500	0.000500	0.000500	0.000500	Maintain a target of 0.000500 in line with Max NPI points.
2-Year Reactor Trip Rate (# per 7,000 hours)	0.50	0.00	0.05	0.33	0.36	0.00	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	Maintain a target of 0.50 in line with Max NPI points.
3-Year Auxiliary Feedwater System Unavailability (#)	0.0200	0.0000	0.0015	0.0111	0.0181	0.0000	0.0200	0.0200	0.0200	0.0200	0.0200	0.0200	0.0200	0.0200	Maintain a target of 0.0200 in line with Max NPI points.
3-Year Emergency AC Power Unavailability (#)	0.0250	0.0001	0.0024	0.0115	0.0000	0.0000	0.0250	0.0250	0.0250	0.0250	0.0250	0.0250	0.0250	0.0250	Maintain a target of 0.0250 in line with Max NPI points.
3-Year High Pressure Safety Injection Unavailability (#)	0.02000	0.00000	0.00003	0.00217	0.00000	0.00000	0.02000	0.02000	0.02000	0.02000	0.02000	0.02000	0.02000	0.02000	Maintain a target of 0.0200 in line with Max NPI points.
Reliability															
WANO NPI (Index)		97.2	91.2	80.5	[illegible]	92.1 ⇩	[illegible]	88.8	[illegible]	94.3	[illegible]	93.8	72.2	98.1	2018 targets calculated based on targets of NPI sub-indicators
Rolling Average Forced Loss Rate (%)	1.00	1.03	1.29	6.48	[illegible]	2.85	5.50	1.00	5.00	1.00	5.00	1.00	5.00	1.00	2018 targets based on Long-Term Outlook production submission.
Rolling Average Unit Capability Factor (%)	92.0	89.44	86.49	78.71	[illegible]	89.41	79.85	82.35	[illegible]	92.00	[illegible]	89.85	[illegible]	89.65	2018 targets are based on Long-Term Outlook submission. More work is underway through the tri-gen meetings to finalize the generation targets.
Rolling Average Chemistry Performance Indicator (Index)	1.01	1.00	1.00	1.05	1.04 ⇧	1.00	1.04	1.01	1.03	1.01	1.03	1.01	1.03	1.01	2018 targets maintained from 2017 approved targets to achieve third quartile at Pickering and best quartile at Darlington (NPI Max points)
1-Year Online Deficient Maintenance Backlog (work orders per unit)[3]		159	212	289	276 ⇩	176 ⇩	196	180	196	175	196	~~175~~ 150	196	150	2018 targets set to maintain best quartile at Darlington and second quartile at Pickering. PN: Target maintained at 196 for 2016-2018 (second quartile). DN: Targeting higher completion of DC's versus DN's to align to implementation of new ERI revision in 2016. 2016 target reflects approved BP target. 2017 and 2018 targets reflect top quartile performance based on latest INPO Q4 benchmark results.
1-Year Online Corrective Maintenance Backlog (work orders per unit)[3]		11	20	37	[illegible]	20 ⇧	[illegible]	25	28	~~25~~ 20	28	~~17~~ 15	28	10	2018 targets set to maintain third quartile at Pickering and best quartile at Darlington. PN: Target maintained at 28 for 2016-2018 (third quartile). DN: • 2016 and 2017 targets reduced from approved BP to show continuous improvement. 2018 target reflects top quartile performance based on latest INPO Q4 benchmark results.
Value for Money															
3-Year Total Generating Costs per MWh ($ per Net MWh)[4,5]		38.79	44.89	57.24	[illegible]	34.42	[illegible]	~~45.93~~ 49.18	[illegible]	~~43.09~~ 44.63	[illegible]	[illegible]	[illegible]	55.66	2015-2017 targets incorporate the final Corporate allocations and Refurb cost reclass items. 2018 targets are based on the LTO cost submission and are draft.
3-Year Non-Fuel Operating Costs per MWh ($ per Net MWh)[4,5]		22.76	25.83	32.07	[illegible]	26.69	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	2015-2017 targets incorporate the final Corporate allocations including the Refurb transfer. 2018 targets reconcile to the Long Term Outlook.
3-Year Fuel Costs per MWh ($ per Net MWh)[4]		7.87	8.63	9.97	5.48	4.95	~~5.70~~ 5.89	~~6.18~~ 5.22	~~5.90~~ 5.73	~~5.43~~ 5.16	~~5.99~~ 5.82	~~5.26~~ 5.30	5.05	5.51	Fuel costs reflect annual generation assumptions.
3-Year Capital Costs per MW DER (k$ per MW)[4,5]		50.88	66.83	108.64	29.47	21.56	~~26.77~~ 29.56	~~42.43~~ 59.84	~~7.74~~ 10.81	~~53.24~~ 52.00	~~3.27~~ 3.38	~~65.27~~ 65.89	3.84	53.92	Targets are set based on capital project portfolio ceilings and reflect Refurb cost reclass items.
Human Performance															
18-Month Human Performance Error Rate (# per 10k ISAR hours)		0.0020	0.0040	0.0080	[illegible]	0.0062	0.0060	0.0040	0.0030	0.0030	0.0030	0.0020	0.0030	0.0020	2018 targets set to maintain second quartile at Pickering and best quartile at Darlington. PN: • Best Quartile requires a maximum 1 EFDR (annual) and 2 EFDRs (18-months) • Second quartile requires a maximum 2 EFDRs (annual) and 3 EFDRs (18-months). DN: • 2016 and 2017 targets reflect approved BP targets and represent 1 EFDR (annual) • 2018 target maintains best quartile at Darlington reflecting 1 EFDR (annual)

ED Interrogatory #18

Issue Number: 6.5
Issue: Are the test period expenditures related to extended operations for Pickering appropriate?

Interrogatory

Reference:
Reference: Ex. F2, Tab 2, Schedule 3

a) Please find attached our calculations of OPG's forecast of the Pickering Nuclear Station's operating and fuel costs for 2017, 2018, 2019 and 2020 broken out by sixteen components. Please confirm and/or correct our calculations for each component and each year. Please also confirm that the table includes all components and that the total is correct.

b) Please provide the Pickering Nuclear Station's actual operating and fuel costs for 2014 and 2015 broken out by the sixteen components listed in our attached file.

Response

a) and b):

OPG is unable to confirm the calculations or rationale for the derivation of Pickering Operating and Fuel Costs in the attached table to Ex. L-6.5-7 ED-18.

Consistent with OPG's response to EB-2013-0321 Undertaking JT1.14, OPG's payment amounts application for the 2017 - 2021 period was prepared on the basis of a single overall nuclear rate. OPG does not calculate separate rates for Pickering and Darlington and OPG does not have a station-level allocation methodology for rate making purposes.

OPG would note that Environmental Defence's methodology for allocating costs is inconsistent with OPG's approved allocation methodology (see Ex. F3-1-1) and that depreciation, property tax and income tax are not classified as "OM&A" which is why OPG excludes those cost elements from its calculation of total operating costs (see Ex. L-6.5-8 GEC-38).

OPG benchmarks its financial performance against other utilities. The EUCG Non-Fuel Operating Cost per MWh ("NFOC") represents one such metric and includes Base OM&A, Outage OM&A, Project OM&A, Corporate Support & Administrative costs and some component of centrally held costs (excluding various OPEB and Pension costs). NFOC is derived by OPG for both Darlington and Pickering to allow OPG to benchmark financial performance and operating costs by station.

OPG also notes that the amounts included in the attached table to Ex. L-6.5-7 ED-18 for Pickering Extended Operations OM&A costs appear to have been "double counted" since these costs would also be reflected in amounts for Base OM&A, Outage OM&A and Project OM&A.

To assist Environmental Defence, OPG has prepared Chart 1 below which derives a "Pickering Cost" for the years 2014-2021. Amounts shown in Chart 1 are consistent with the elements included in the EUCG NFOC metric, except for the following adjustments to address the information requested:

- added fuel costs, consistent with Ex. L-6.5-8 GEC-38
- added certain costs that are excluded in deriving NFOC for purposes of EUCG benchmarking, consistent with Ex. L-6.5-8 GEC-38
- removed certain capital costs that are included in deriving NFOC for purposes of EUCG benchmarking, consistent with Ex. L-6.5-9 GEC-39
- added depreciation, income and property tax, which are not recognized as an operating cost. These costs were derived using an allocation based on Pickering's share of total generation, which appears to be the basis for the allocated amounts included in the table that Environmental Defence sent with ED-18. However, OPG disagrees that share of total generation is an appropriate basis on which to allocate these costs.

Chart 1

($M, unless otherwise stated)	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Total Operating Costs - Initial	1,276.5	1,249.9	1,364.0	1,351.4	1,351.4	1,391.7	1,337.9	1394.5
Add								
Inventory Obsolescence[1]	0.0	0.0	12.4	12.4	12.4	12.4	12.4	12.4
Pickering portion of Tritium Removal Facility[1]	0.0	0.0	10.4	11.2	11.6	10.9	12.2	12.8
Fuel Costs	113.5	120.4	120.2	114.4	115.5	116.5	120.5	117.9
Subtotal	**1,390.0**	**1,370.3**	**1,507.0**	**1,489.4**	**1,490.9**	**1,531.5**	**1,483.0**	**1537.6**
Less								
Capital	119.5	90.9	124.3	85.2	29.8	28.0	23.2	23.1
Subtotal	**1,270.5**	**1,279.4**	**1,382.7**	**1,404.2**	**1,461.1**	**1,503.5**	**1,459.8**	**1514.5**
Add								
OPEB and Pension excluded from Centrally Held Costs	10.7	45.8	48.5	62.7	39.2	25.5	15.7	10.0
IESO Non energy Charges[2]	32.2	51.5	27.6	30.6	28.2	25.7	28.7	22.3
Other[1]	0.0	0.0	-3.7	-68.6	-37.3	-25.8	-30.6	-22.7
Subtotal	**1,313.4**	**1,376.7**	**1,455.1**	**1,428.8**	**1,491.2**	**1,529.0**	**1,473.5**	**1546.8**
Add								
Depreciation and Amortization _Pickering[2]	140.9	147.3	165.7	199.9	223.2	226.7	233.3	53.1
Depreciation and Amortization- Pickering Generic[2]	44.2	53.5	34.2	38.6	37.1	34.9	36.7	20.4
Income Tax - Pickering[2]	-25.7	-15.2	-8.3	-9.2	-9.2	-9.1	26.9	27.5
Property Tax- Pickering	4.9	4.9	5.0	5.4	5.5	5.7	5.8	6.3
Total								
Planned Operating Costs	**1,477.6**	**1,567.2**	**1,651.7**	**1,663.6**	**1,747.9**	**1,787.2**	**1,776.2**	**1654.0**
Pickering Generation - TWh	**20.1**	**21.2**	**20.8**	**19.1**	**19.2**	**19.4**	**19.6**	**18.8**
Planned Operating Costs- $/MWh	**73.5**	**73.8**	**79.5**	**87.3**	**91.1**	**92.3**	**90.5**	**87.9**

[1] Included in Total Operating Costs- Initial in 2014 actual and 2015 actual
[2] Allocation based on Pickering % of generation

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

in millions	2015	2016	2017	2018	2019	2020	2021	Total
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.

period, 2020 to 2024, we're producing almost 69 terawatts of additional production during that time period.

MR. RUBENSTEIN: If the IESO analysis and your analysis were re-run -- I'm not asking you to do that, but if they were re-run and the answer showed there was no economic benefit, would OPG still believe this project is reasonable?

MR. BLAZANIN: It's a complicated question, all right. And it's complicated because you're looking over a long period of time. You're not looking over a one or two-year horizon in terms of investment. You're talking about a major facility that produces about 10 percent of the power for the province of Ontario. It provides reliable, sustainable base load generation, and there are a number of factors could swing the economics up and down.

We talked about things like gas prices yesterday, and I believe there were numbers provided that showed that gas prices were coming down generally. So could that affect it? Sure.

But then there are other things like carbon prices, and we're seeing carbon prices coming into play with the cap and trade system and everything else, and I believe the recent floor auction was around 18 to 20 dollars that was based on that, and we'll see how that transpires.

So there's a lot of things can fluctuate. While in a moment's time, you could have a positive benefit, something could turn that economic benefit negative. But then a year later, it could turn the other way as well.

Board Staff Interrogatory #119

Issue Number: 6.5
Issue: Are the test period expenditures related to extended operations for Pickering appropriate?

Interrogatory

Reference:
Ref: Exh F2-2-3 Attachment 2 page 7
At the above reference OPG discusses the mitigation measures available to it to address pressure tube elongation. OPG states, "Some of the physical modifications which are available would be costly to implement and some of the technical solutions are complex and/or would require increasing the complexity of operational procedures. **Therefore, the preliminary plans to enable the Preferred Alternative include only the less costly physical modifications and less complex technical evaluations**". [Emphasis Added].

a) It appears the plans to enable PEO rely on "less costly physical modifications and less complex technical evaluations", specifically in relation to Fuel Channels. Please explain the rationale for this approach, how it impacts the benefits analysis conducted by the IESO and OPG respectively and comment on how OPG proposes to manage the risks and costs should it later be known that more expensive modifications are needed. Please also clarify if the above statement is in relation to OM&A costs or capital expenditures or both.

b) Table A1 provides a forecast of costs needed to fund modifications arising from the Periodic Safety Review. Please provide a breakdown of the costs, describe the types of modifications and explain why costs related to modifications to the physical plant are being treated as OM&A rather than capital.

Response

a) The "less costly physical modifications" to safely manage fuel channel elongation and available bearing life to enable Pickering Extended Operations are fuel channel shifting and/or reconfiguration, which is a process currently employed at OPG facilities.

The "less complex technical evaluations" include refinement of elongation assessments using refined measurements and probabilistic assessments.

In addition, the potential use of depleted fuel and/or operation with some channels defueled is being evaluated as part of the Fuel Channel Life Assurance project. These fuel strategies are only intended to be employed if shifting or reconfiguration is not successful on individual channels due to component interferences, or to minimize the amount of shift or reconfiguration that must be completed.

This suite of tools, assessments and strategies to manage and mitigate fuel channel elongation is expected to be successful. It is noteworthy that project work completed to date has increased OPG's confidence in its ability to operate Pickering to 2022/2024 using these tools.

Using the more expensive physical modification alternative is considered very unlikely given the work completed to date. However if the existing plan was proven to be unsuccessful, then the more expensive alternatives would need to be re-evaluated.

The work programs described above are all considered OM&A and have been included in the extended operations costs and production forecasts assessed in the economic assessment prepared by the IESO.

b) The work program associated with the Periodic Safety Review is progressing but is not complete. Accordingly, a list of potential modifications has not been finalized. Until the scope of a specific modification is defined, determining if a project meets the capitalization criteria is not possible. As a result, project expenditures were classified as OM&A for planning purposes. To the extent some of the costs are determined to be capital at a later date, the revenue requirement impact of the different classification will be captured through the Capacity Refurbishment Variance Account.

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.

OPG does not confirm that the revenue requirement impact of any VBO costs underpinning payment amounts would be credited to the Capacity Refurbishment Variance Account. As discussed in Ex. L-6.9-1 Staff 178(c), only expenditures to increase the output of, refurbish or add operating capacity to a prescribed generation facility fall within the definition of the CRVA pursuant to O. Reg. 53/05. Since the VBO does none of these things, any changes in VBO costs would not be captured within the CRVA.

c) The incremental budget for the VBO is $46M. The total amount has been budgeted in 2021 under the Pickering total found in Ex. F2-4-1 Table 1, Line 2. There currently are no VBO preparation costs included in the 2020 forecast. The final scope has not been defined and accordingly preparatory expenditures could not be distributed. When the final scope is defined, costs will be distributed between the station and support departments and an appropriate share allocated for preparations in the years preceding execution.

d) Refer to part (c). There are no VBO costs included in 2020 in Ex. F2-4-1, p. 2, Chart 2.

e) Chart 1 below provides a summary of incremental costs associated with the 2010 VBO compared to the 2021 budget as described in part (c). Total incremental costs are on par with the 2010 VBO assuming a 2% escalation factor. As stated in part (c) above, the 2021 VBO scope has not been finalized. Therefore, an explanation of differences in costs cannot be provided.

Chart 1

Organization	**2010 VBO Actual Costs**	**2021 VBO Budget**
Pickering Nuclear	29.7	46.2
Support Organizations	5.9	Not available
Total ($M)	**35.7**	**46.2**

EP Interrogatory #22

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

Interrogatory

Reference:

Can OPG list the amount of power (in TWh) it has curtailed from its nuclear reactors in 2013, 2014, 2015 and to date in 2016. Can it do so quarterly.

Response

OPG very rarely is asked to curtail power from its nuclear reactors. Below is a list of quarters where OPG was asked to curtail power and the amounts.

2013-Q2 – 0.002TWh
2016-Q3 – 0.02TWh

Each of these reductions has been at Darlington. Pickering has not been asked to curtail power in the requested time period.

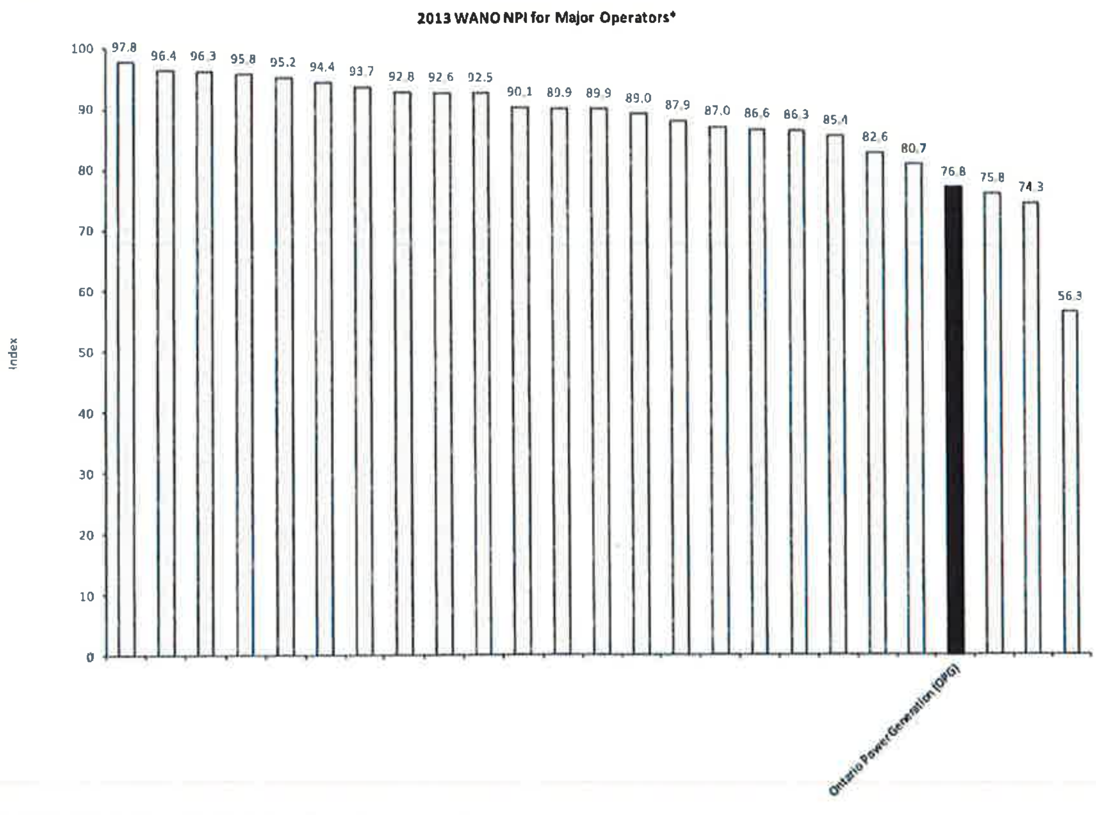
6.0 MAJOR OPERATOR SUMMARY

Purpose

This section supplements the Executive Summary, providing more detailed comparison of the major operators of nuclear plants for three key metrics: WANO Nuclear Performance Index (NPI), Unit Capability Factor (UCF), and Total Generating Cost (TGC) per MWh. Although the benchmarking study has been primarily focused on operational performance comparison to COG CANDUs, this section of the report contemplates the larger industry by capturing OPG Nuclear's performance against North American PWR and PHWR operators in addition to the international CANDU panel. Operator level summary results are the average (mean) of the results across all plants managed by the given operator. These comparisons provide additional context, but the detailed data in the previous sections provide a more complete picture of plant by plant performance. The WANO NPI and UCF are calculated as the mean of all unit performance for a specific operator. The TGC per MWh is the mean of plant level data because costs are not allocated to specific units within the EUCG industry panel.

WANO Nuclear Performance Index Analysis

The WANO Nuclear Performance Index (NPI) results for the operators in 2013 are illustrated in the graph below. OPG Nuclear performance ranking improved slightly from 2012 as shown in Table 3.



*See Table 7 in the Appendix for listing of operators and plants.

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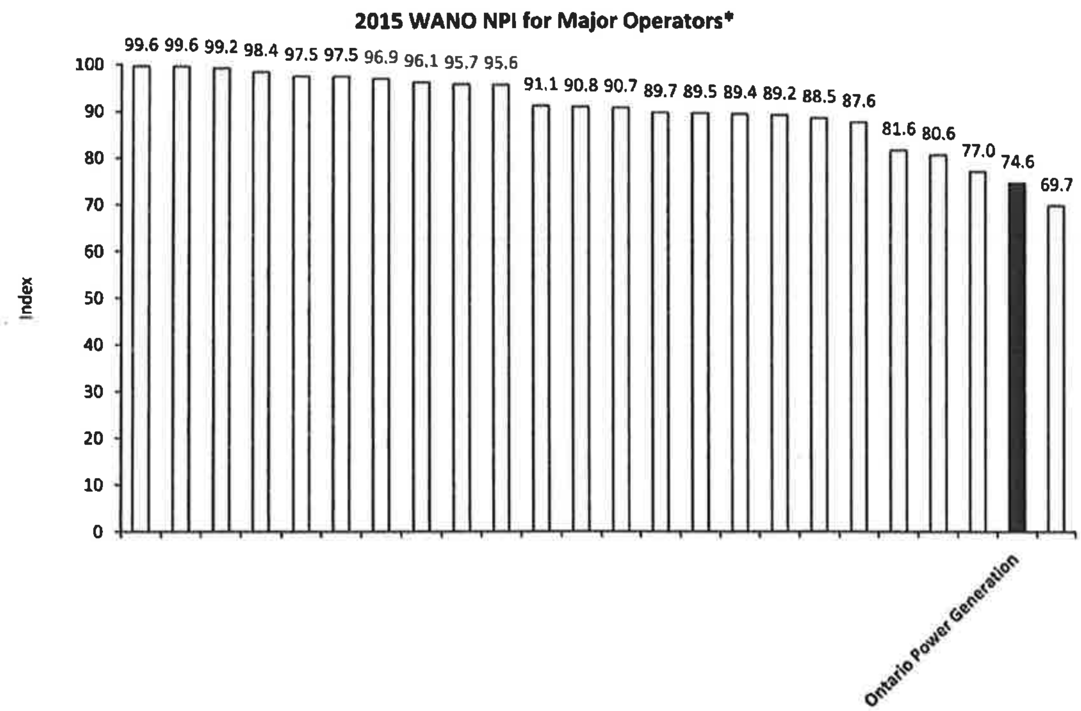
WANO Nuclear Performance Index Analysis

The WANO Nuclear Performance Index (NPI) results for the operators in 2015 are illustrated in the graph below. OPG Nuclear performance ranking fell from 2014 shown in Table 3.



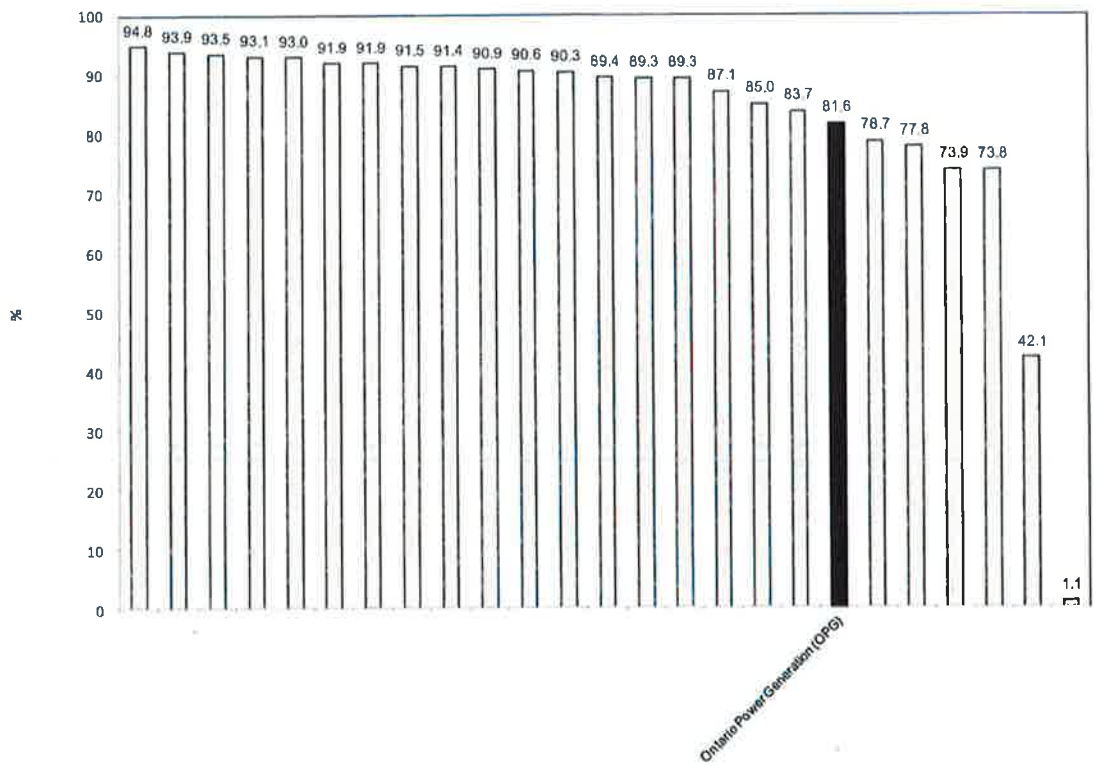
*See Table 7 in the Appendix for listing of operators and plants.

Unit Capability Factor Analysis

Unit Capability Factor (UCF) is the ratio of available energy generation over a given time period to the reference energy generation of the same time period, expressed as a percentage. Reference energy generation is the energy that could be produced if the unit were operating continuously at full power under normal conditions. Since nuclear generation plants are large fixed assets, the extent to which these assets generate reliable power is the key to both their operating and financial performance.

A comparison of UCF values for major nuclear operators is presented in the graph below. UCF is expressed as a two-year average for all operators except for OPG Nuclear, which includes a three-year average for the Darlington station and a two-year average for Pickering. OPG Nuclear achieved a rolling average UCF of 81.6% and ranked 19 out of 25 operators in the WANO data set. The list and ranking of operators has been updated to reflect industry developments.

2013 Rolling Average Unit Capability Factor Ranking for Major Operators*



* See Table 7 in the Appendix for listing of operators and plants.

**OPG unit values averaging to a rolling average UCF of 81.6% in 2013 are shown below:

Unit	2013 Rolling Average UCF
Pickering 1	56.2
Pickering 4	80.3
Pickering 5	78.6
Pickering 6	82.4
Pickering 7	81.0
Pickering 8	76.2

Unit	2013 Rolling Average UCF
Darlington 1	92.3
Darlington 2	86.9
Darlington 3	93.3
Darlington 4	89.3

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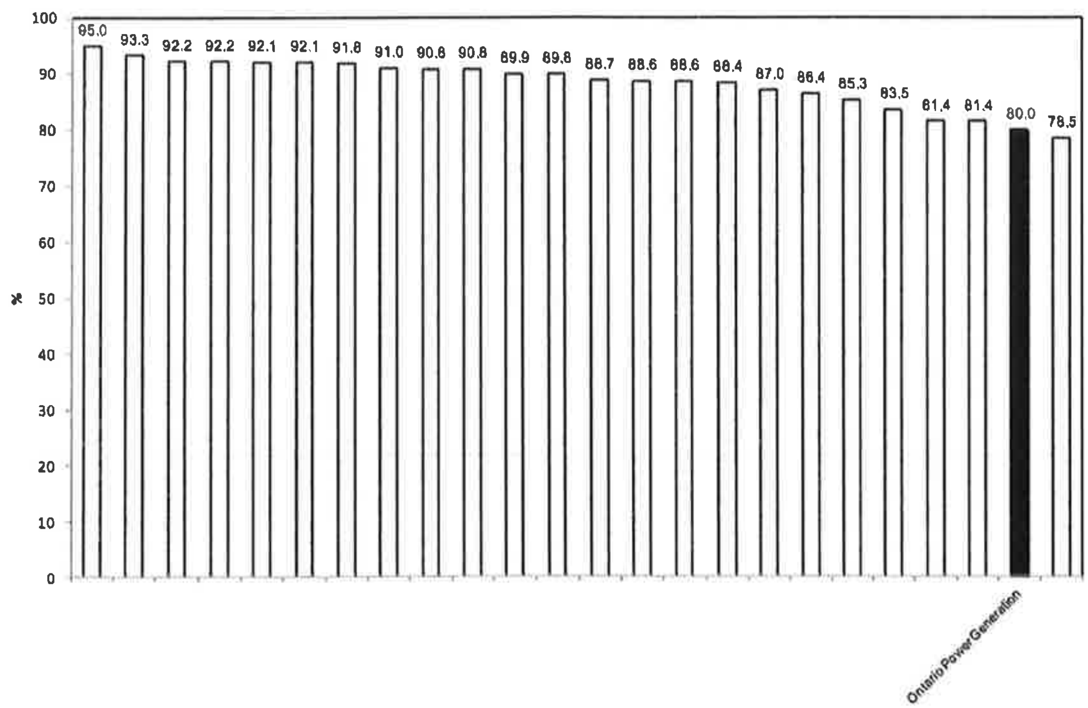
Unit Capability Factor Analysis

Unit Capability Factor (UCF) is the ratio of available energy generation over a given time period to the reference energy generation of the same time period, expressed as a percentage. Reference energy generation is the energy that could be produced if the unit were operating continuously at full power under normal conditions. Since nuclear generation plants are large fixed assets, the extent to which these assets generate reliable power is the key to both their operating and financial performance.

A comparison of UCF values for major nuclear operators is presented in the graph below. UCF is expressed as a two-year average for all operators except for OPG Nuclear, which includes a three-year average for the Darlington station and a two-year average for Pickering to reflect each plant's respective outage cycle. OPG Nuclear achieved a rolling average UCF of 80.0% and ranked 23 out of 24 operators in the WANO data set. The list and ranking of operators has been updated to reflect any industry developments if applicable.

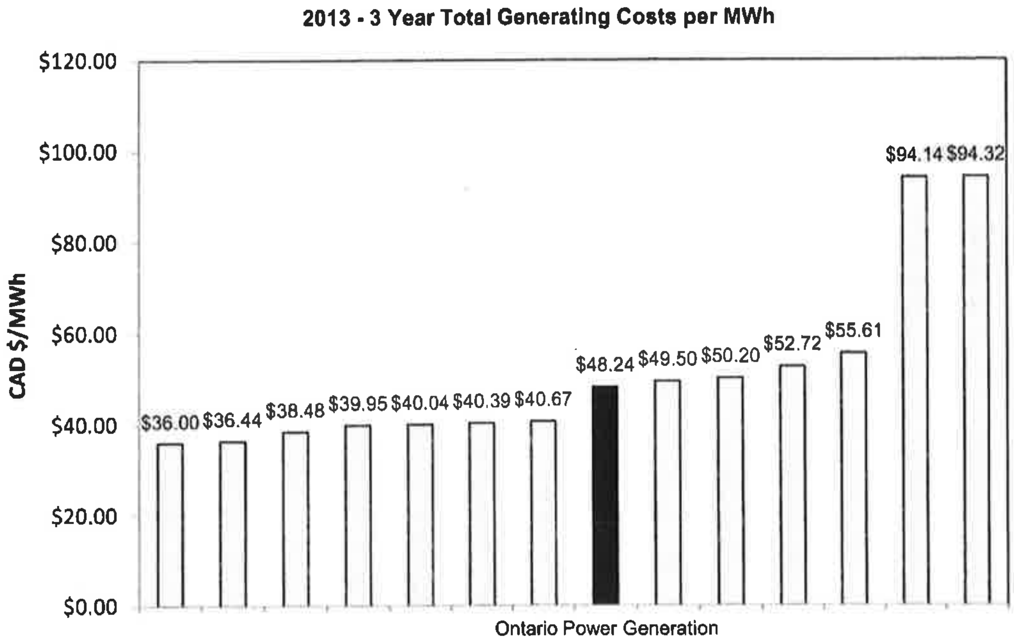
2015 Rolling Average Unit Capability Factor Ranking for Major Operators*



* See Table 7 in the Appendix for listing of operators and plants.
**OPG unit values averaging to a rolling average UCF of 80.0% in 2015 are shown below:

Unit	2015 Rolling Average UCF
Pickering 1	72.8
Pickering 4	79.4
Pickering 5	80.9
Pickering 6	78.3
Pickering 7	77.8
Pickering 8	74.7

Unit	2015 Rolling Average UCF
Darlington 1	82.5
Darlington 2	82.9
Darlington 3	87.0
Darlington 4	83.4



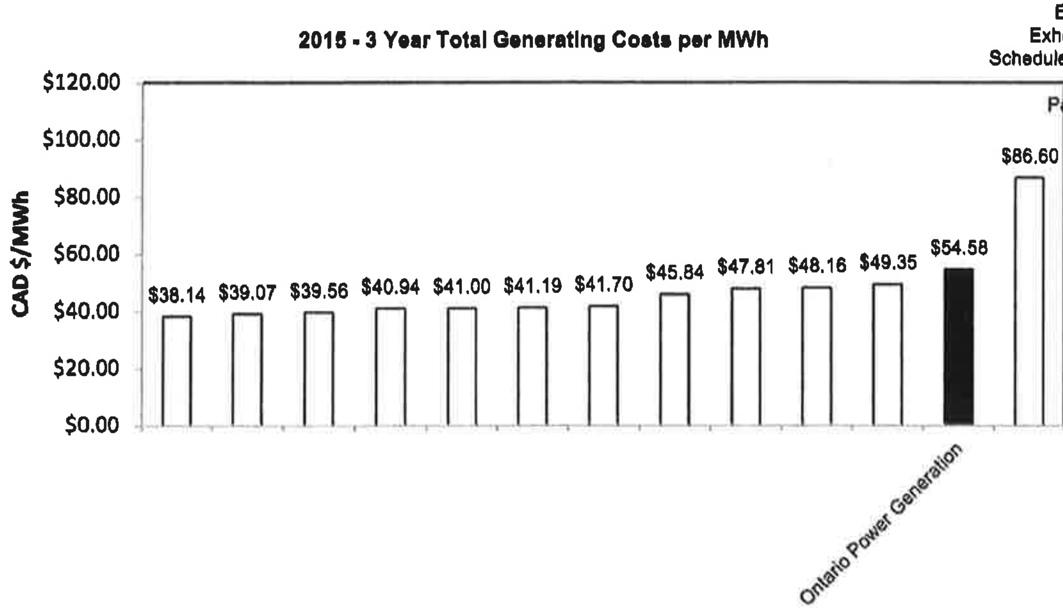
*OPG plant values of 3-year rolling average TGC per MWh are shown below:

Unit	2013 3-Year TGC
Darlington	$34.42/MWh
Pickering	$67.18/MWh

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

	2008	2009	2010	2011	2012	2013
	11	11	9	7	4	1
	6	5	3	1	1	2
	1	2	2	3	3	3
	3	3	4	4	5	4
	4	4	5	5	6	5
	2	1	1	2	2	6
	10	10	10	8	7	7
Ontario Power Generation	14	12	12	12	10	8
	9	8	11	11	11	9
	8	7	7	9	9	10
	NA	NA	NA	NA	NA	11
	7	9	8	10	12	12
	12	13	13	14	13	13
	13	14	14	13	14	14

Note: An operator has been removed from the panel due to an acquisition by another operator in the panel. An additional operator was added to the panel to maintain year-over-year panel size.



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

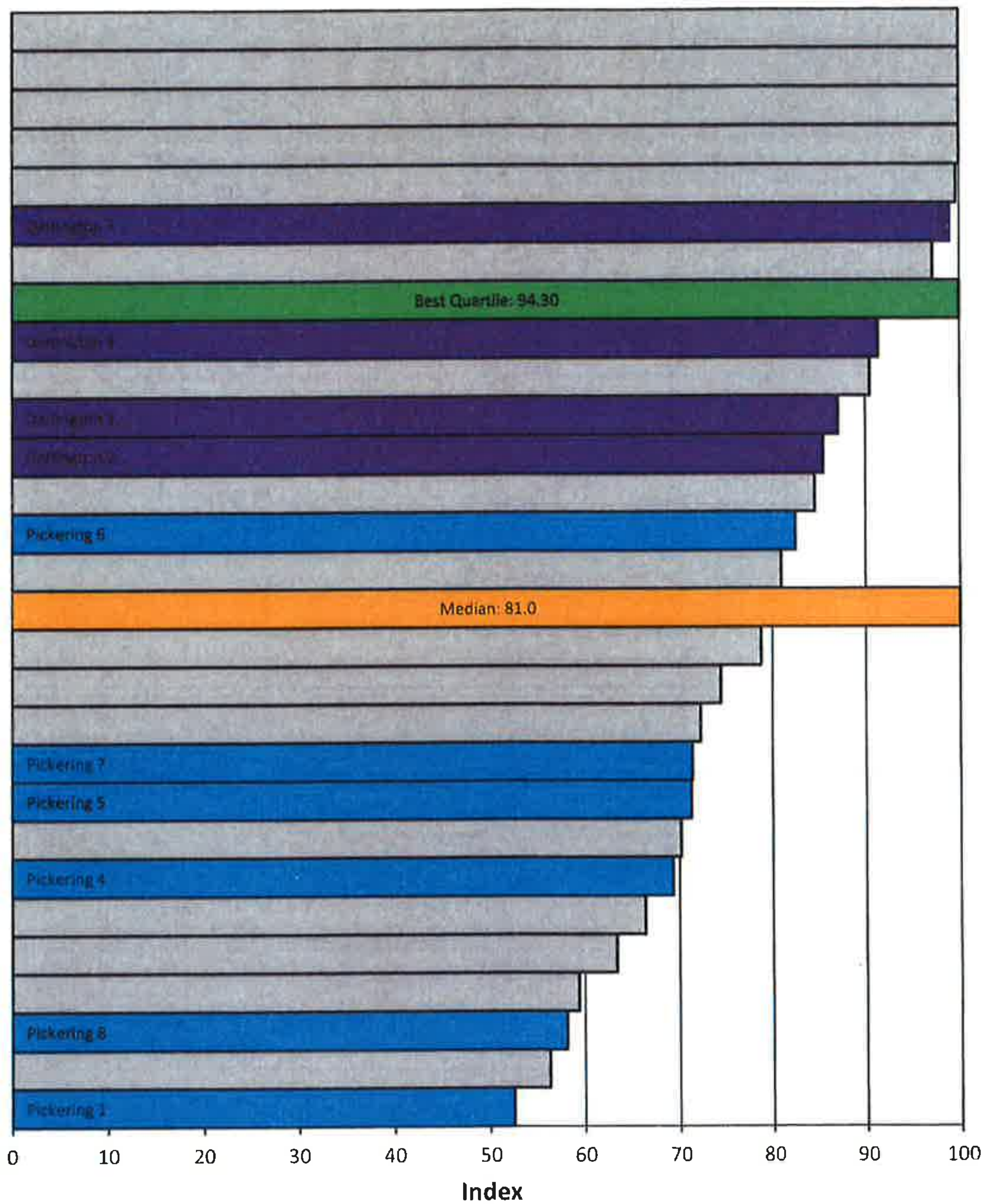
Unit	2015 3-Year TGC
Darlington	$44.38/MWh
Pickering	$67.36/MWh

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).

2013 WANO Nuclear Performance Index
CANDU Unit Level Benchmarking



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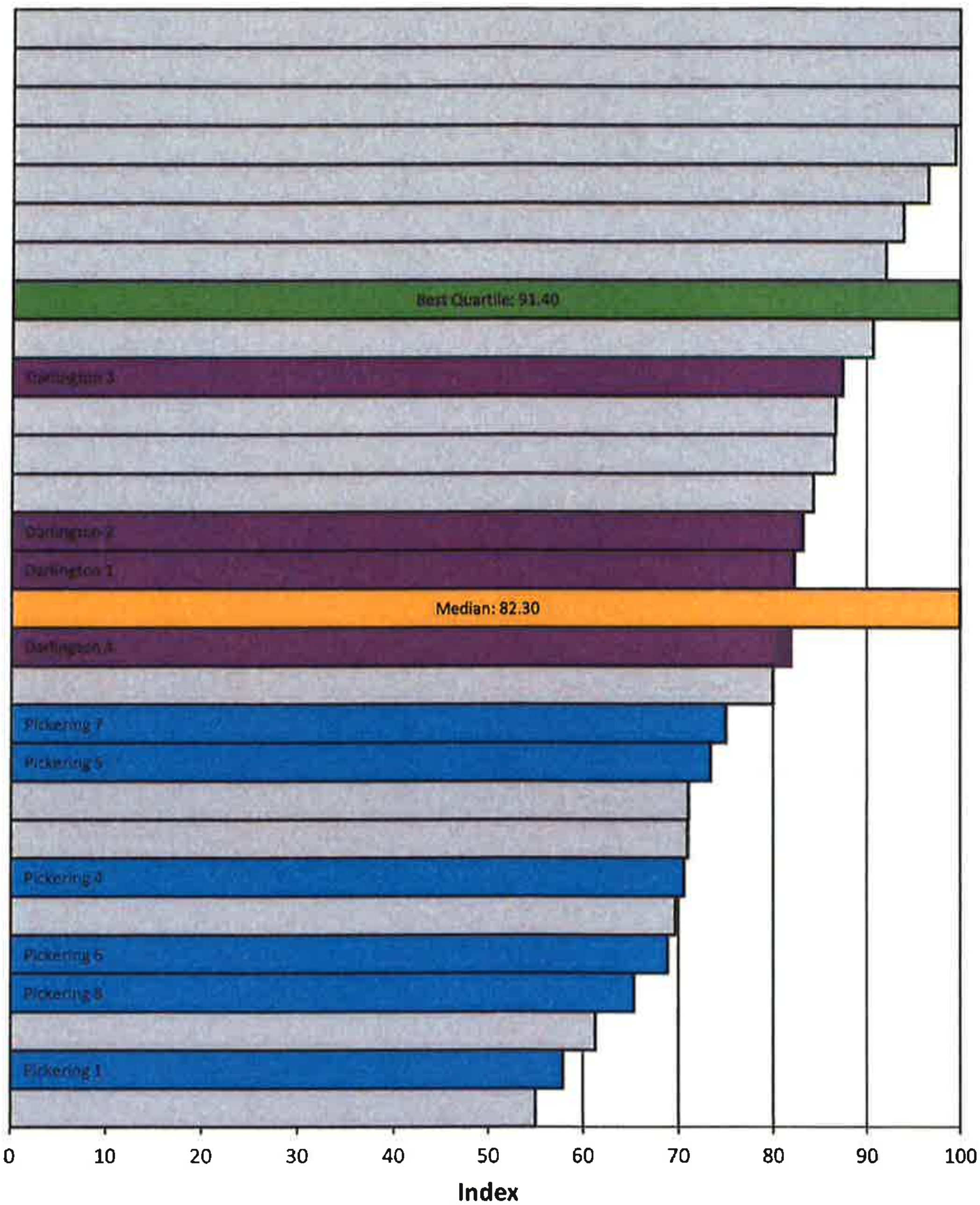
2015 WANO Nuclear Performance Index
CANDU Unit Level Benchmarking



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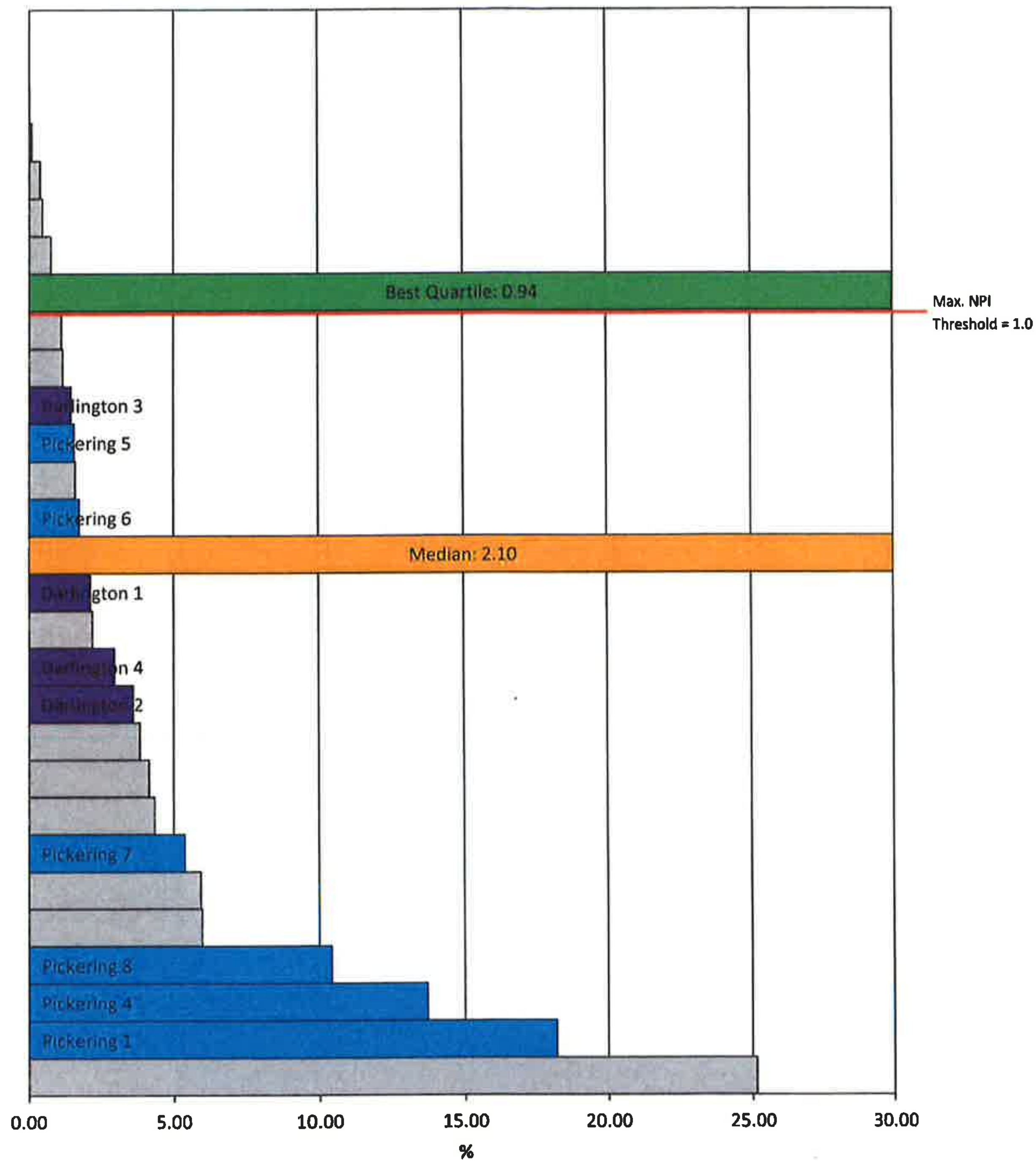
2013 Rolling Average Forced Loss Rate
CANDU Plant Level Benchmarking



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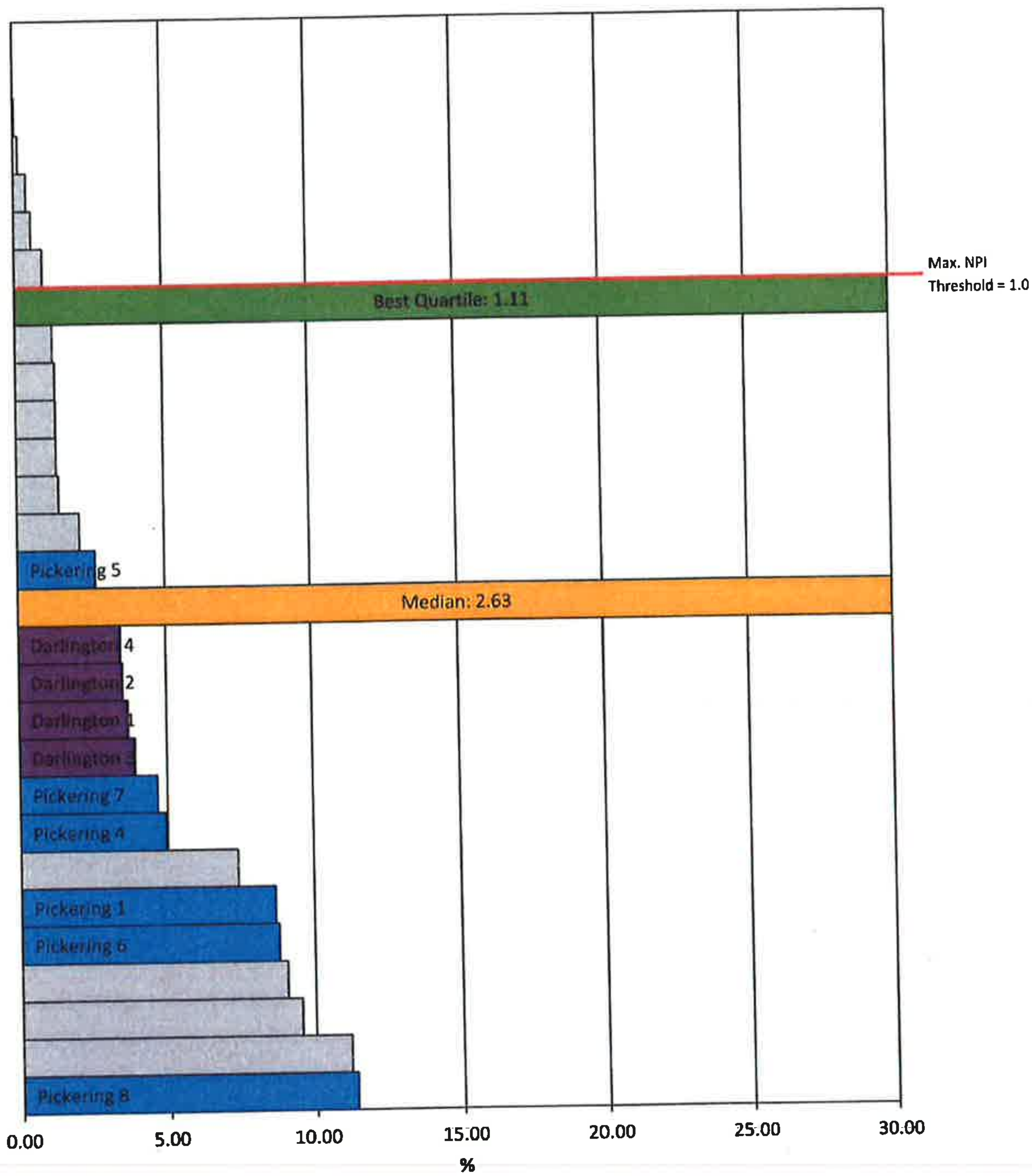
2015 Rolling Average Forced Loss Rate
CANDU Unit Level Benchmarking



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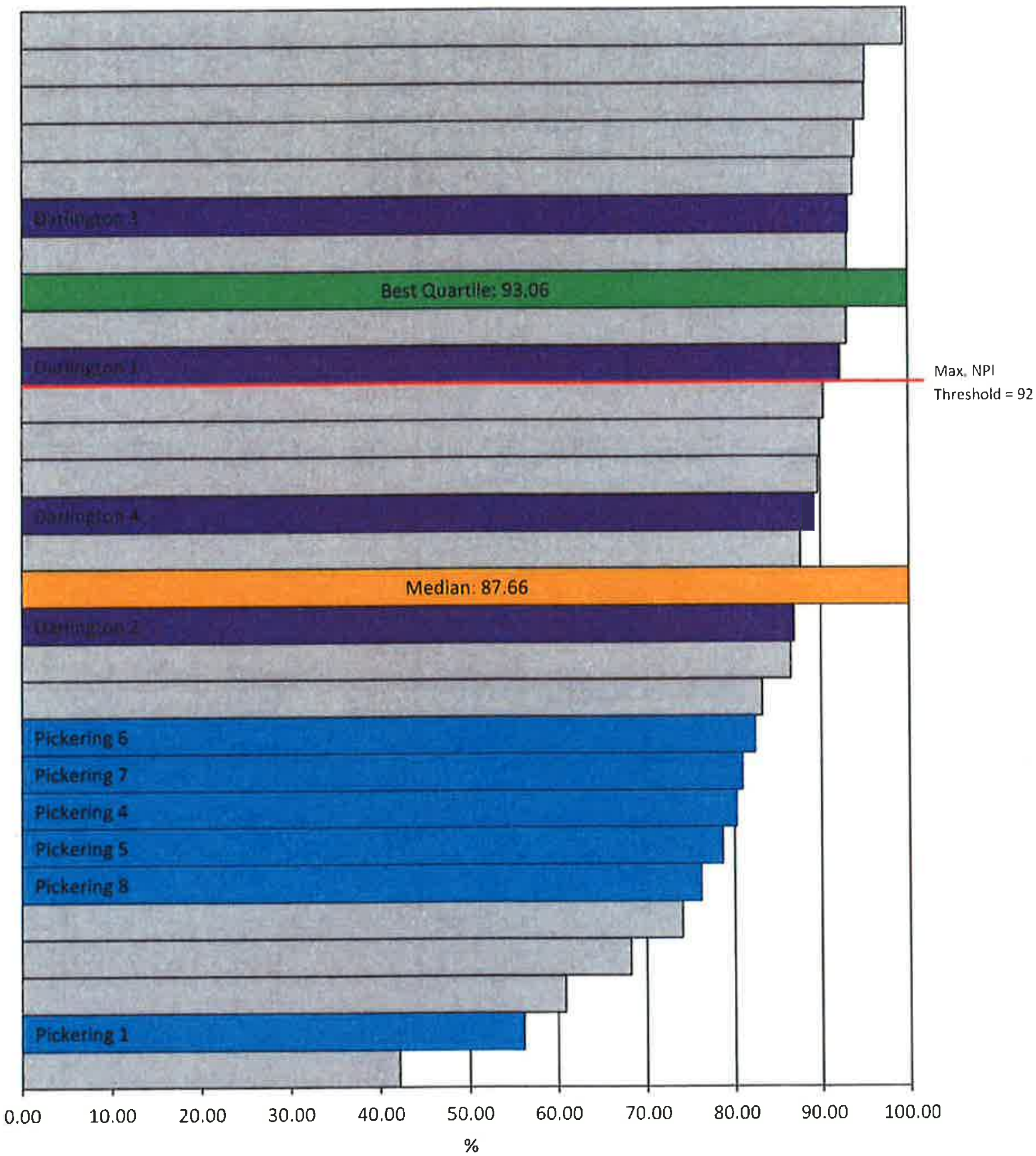
2013 Rolling Average Unit Capability Factor
CANDU Unit Level Benchmarking



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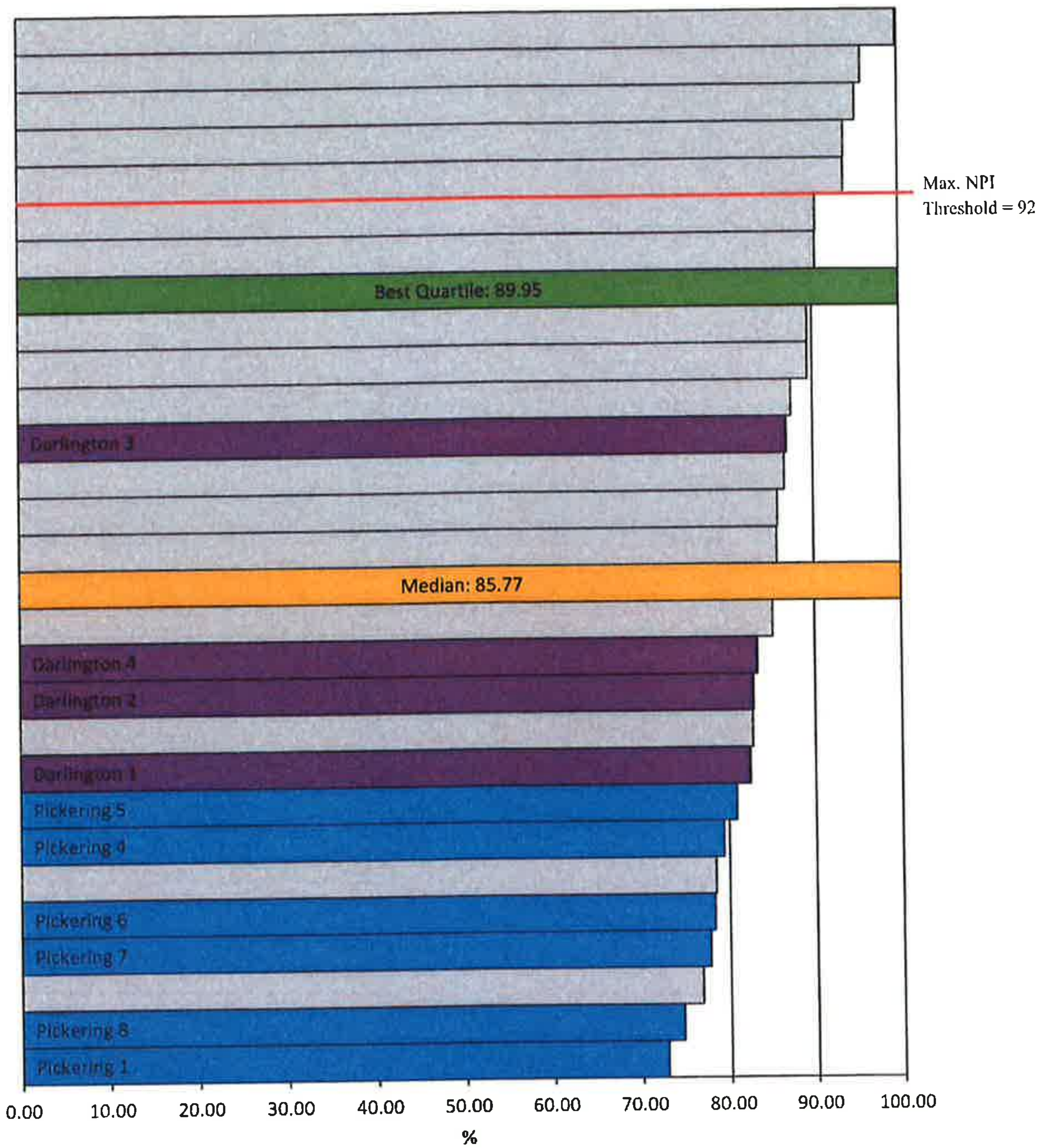
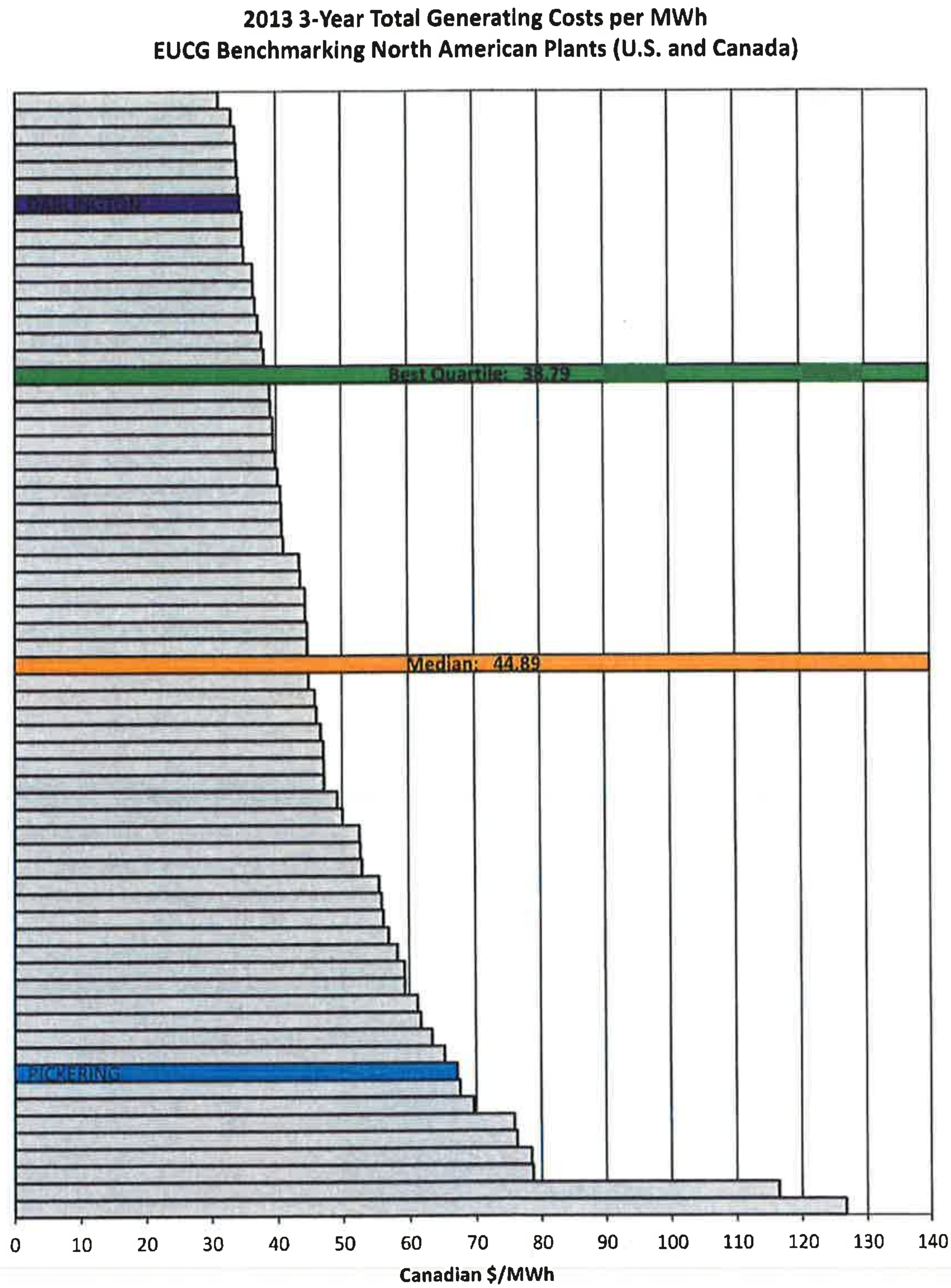
2015 Rolling Average Unit Capability Factor
CANDU Unit Level Benchmarking



3-Year Total Generating Cost per MWh



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3-Year Total Generating Cost per MWh