EB-2016-0152

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act 1998*, Schedule B to the *Energy Competition Act*, 1998, S.O. 1998, c.15;

AND IN THE MATTER OF an application by Ontario Power Generation Inc. pursuant to section 78.1 of the *Ontario Energy Board Act, 1998* for an Order or Orders determining payment amounts for the output of certain generation facilities.

CROSS-EXAMINATION COMPENDIUM OF THE SCHOOL ENERGY COALITION (Panel 2Aii)

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VIA E-MAIL AND WEB POSTING

February 17, 2015

To: All Participants in EB-2012-0340
All Participants in EB-2013-0321
All Other Interested Parties

Re: Incentive Rate-setting for Ontario Power Generation's Prescribed Generation Assets

This letter addresses the Board's expectations regarding the next steps in the development of an incentive rate-setting (IR) mechanism.

The Board continues to believe that it is appropriate to incorporate IR into the rate-setting mechanism for OPG, as reflected in the Board's March 28, 2013 *Report of the Board: Incentive Rate-making for Ontario Power Generation's Prescribed Generation Assets*[1] (the Board Report) and the Board's recent decision on OPG's 2014/15 cost of service application[2]. A long-term, properly designed IR mechanism has the potential to lead to operational efficiencies and innovation, and thus lower electricity costs. The Board also continues to be of the view that the differences between hydroelectric and nuclear technologies justify the separate approaches discussed in the Board Report including:

1) An IR mechanism for OPG's hydroelectric assets.
2) A longer term approach to payment amount-setting for the nuclear assets that focuses on the parameters for a multi-year cost of service application while incorporating elements of IR.

However, the Board will not be establishing working groups as initially intended to lead consultations on the development of the IR frameworks.

In the two years since the issuance of the Board Report, the Board has implemented the *Renewed Regulatory Framework for Electricity* (RRFE), including the adjudication of the first custom IR applications under this new framework.

[1] EB-2012-0340, Board Report, pages 8, 9
[2] EB-2013-0321, Decision with Reasons, dated November 20, 2014, page 129

In addition, the Board understands that OPG is in the process of consulting with stakeholders (including intervenors and Board staff) on OPG's proposals for its upcoming application. At OPG's recent information sessions[3], OPG informed stakeholders that it has targeted mid 2015 for the filing of a comprehensive payment amount application to take effect on January 1, 2016. The filing would include OPG's proposed mechanism for hydroelectric IR, a five year application that implements the proposed IR mechanism, and a five year application for the nuclear assets.

Given the progress already made by OPG, the Board sees no need to establish its own working groups and looks forward to receiving OPG's application.

The Board expects OPG to develop an IR framework for its hydroelectric assets, and a custom IR framework for its nuclear assets based on the principles outlined in the RRFE. The Board expects that the framework for hydroelectric will take into consideration the productivity study, *Empirical Analysis of Total Factor Productivity Trends in North American Hydroelectric Generation Industry,* recently filed by OPG in accordance with the Board's direction in its recent 2014/15 cost of service payment amounts decision.

In the absence of an IR framework for both hydroelectric and nuclear, the Board expects to consider a threshold question at the commencement of the proceeding to determine whether the application should proceed.

Yours truly,

Original signed by

Kirsten Walli
Board Secretary

[3] To date, information sessions were held on December 17, 2014 and January 22, 2015

Ontario Energy Board

Commission de l'énergie de l'Ontario

Handbook
for
Utility Rate Applications

October 13, 2016

Although the RRFE was developed specifically for electricity distributors, the OEB has for some time indicated that the principles underpinning the RRFE are applicable to all regulated utilities (natural gas utilities, electricity distributors, electricity transmitters and Ontario Power Generation).

Since the release of the RRFE Report, over half of Ontario electricity distributors have applied for rates under the RRFE. Enbridge Gas Distribution Inc. also applied using the principles of the RRFE. Based on its review of those rate applications, the OEB has now completed an assessment of the RRFE and the principles underpinning it. This Handbook outlines how the RRFE will be applied to all regulated utilities going forward. The framework will be referred to as the *Renewed Regulatory Framework* (RRF) in this document and by the OEB going forward to reflect this transition.

Natural Gas Utilities

Natural gas utilities may choose either Custom IR or Price Cap IR. Under either approach, the term must be a minimum of 5 years. For Price Cap IR it would include a cost of service year and at least four years using an incentive adjustment mechanism.

Ontario Power Generation

The OEB established expectations that payments for OPG will be based on Price Cap IR for the hydroelectric business and Custom IR, based on the RRFE principles, for the nuclear business. The OEB may set out its expectations for future applications in its next decision and order for OPG.

Specific Considerations for Custom Incentive Rate setting

The OEB has now received and decided a number of Custom IR applications and is in a position to provide further guidance on the minimum standards for Custom IR applications to ensure that the performance-focused and outcomes-based approach is achieved as intended. A Custom IR application is by its very nature custom, and therefore no specific filing requirements have been established. However, any utility filing a Custom IR application should be informed by the cost of service filing requirements and this Handbook. The sections that follow set out the OEB's minimum standards for certain key elements of Custom IR applications.

There is no threshold test or eligibility requirement for a Custom IR application. The test for the adequacy of the application is the extent to which its features contribute to the achievement of the OEB's RRF goals and whether it meets the following standards:

- Term: A Custom IR must have a minimum term of five years. The OEB has determined that this term supports a longer term approach to planning to smooth expenditures and pace rate increases, strengthens efficiency incentives and supports innovation. Longer terms can be proposed with appropriate mechanisms for consumer protection as discussed below.

- Index for the Annual Rate Adjustment: The annual rate adjustment must be based on a custom index supported by empirical evidence (using third party and/or internal resources) that can be tested. Custom IR is not a multi-year cost of service; explicit financial incentives for continuous improvement and cost control targets must be included in the application. These incentive elements, including a productivity factor, must be incorporated through a custom index or an explicit revenue reduction over the term of the plan (not built into the cost forecast).

The index must be informed by an analysis of the trade-offs between capital and operating costs, which may be presented through a five-year forecast of operating and capital costs and volumes. If a five-year forecast is provided, it is to be used to inform the derivation of the custom index, not solely to set rates on the basis of multi-year cost of service. An application containing a proposed custom index which lacks the required supporting empirical information may be considered to be incomplete and not processed until that information is provided.

It is insufficient to simply adopt the stretch factor that the OEB has established for electricity distribution IRM applications. Given a utility's ability to customize the approach to rate-setting to meet its specific circumstances, the OEB would generally expect the custom index to be higher, and certainly no lower, than the OEB-approved X factor for Price Cap IR (productivity and stretch factors) that is used for electricity distributors.

- Benchmarking: Benchmarking is a fundamental requirement of a Custom IR application, both internal benchmarking to demonstrate continuous improvement and external benchmarking as identified in Section 5. A Custom IR application without benchmarking will be considered incomplete.

- Performance Metrics: The OEB has established a scorecard for electricity distributors, however, additional performance metrics should also be proposed so that expected outcomes can be monitored. All other utilities must propose a comprehensive scorecard that is informed by the scorecard for electricity distributors, but specifically includes other performance metrics aligned to the outcomes identified in the application. This is required for both Custom IR and cost of service rate applications.

- Updates: After the rates are set as part of the Custom IR application, the OEB expects there to be no further rate applications for annual updates within the five-year term, unless there are exceptional circumstances, with the exception of the clearance of established deferral and variance accounts. For example, the OEB does not expect to address annual rate applications for updates for cost of capital, working capital allowance or sales volumes. In addition, the establishment of new deferral or variance accounts should be minimized as part of the Custom IR application.

The adjudication of an application under the Custom IR method requires the expenditure of significant resources by both the OEB and the utility. The OEB therefore expects that a utility that applies under Custom IR will be committed to that method for the duration of the approved term and will not seek early termination or in-term updates except under exceptional circumstances and with compelling rationale.

A Custom IR application can include a five year forecast of all costs with proposed rates for each year that consider both these costs and the proposed productivity improvements reflected in the custom index. A utility that cannot forecast its needs within the five year term, or does not believe it can operate with this level of uncertainty, should consider whether the Custom IR option is appropriate for its circumstances.

The ICM and ACM mechanisms for funding capital for electricity distributors, or any similar mechanism approved for transmitters, natural gas distributors or OPG, are not available for utilities setting rates under Custom IR.

An acceptable adjustment during a Custom IR term is a Z factor mechanism for cost recovery of unforeseen events. The OEB has a policy for Z factors for electricity distributors and transmitters that applies for any rate-setting option chosen by a utility. The OEB has established a materiality threshold for electricity distributors for eligibility to claim for a Z factor event. Electricity transmitters are expected to propose a materiality threshold in their applications. The OEB has approved Z factor mechanisms for natural gas distributors in previous proceedings, and they may propose mechanisms in their future rate applications.

Given the custom nature of a Custom IR application, utilities may propose alternative mechanisms for unforeseen events to coordinate better with other aspects of their custom proposals. In doing so they should consider the OEB's expectations for protecting customers from excess earnings, as discussed in the next section.

- Protecting Customers: A key objective of incentive regulation is to drive productivity improvements within the utilities. The OEB has determined that with the Custom IR rate setting option, customers will benefit from the expected productivity improvements during the term through the custom index.

  Utilities that achieve productivity improvements above what is expected are allowed to keep certain earnings above the approved ROE. However, the OEB expects utilities filing a Custom IR application to propose one or more mechanisms to protect customers from utility earnings that become excessive. Proposals would typically include mechanisms such as off ramps (discussed below) and earnings sharing but could include other approaches specific to a utility's circumstances.

For electricity distributors, the OEB has established an off-ramp that involves a threshold above the distributor's approved return on equity at which a regulatory review may be triggered.[17] An electricity distributor can propose an alternative threshold that provides greater protection for customers. Other utilities may propose an off-ramp that takes into consideration the OEB's objective of protecting customers from excess earnings.

The OEB does not require a Custom IR to include an earnings sharing mechanism, except in the context of deferred rebasing periods as part of electricity distributor consolidation[18]. While an earnings sharing mechanism protects customers from excess earnings, it can diminish the incentives for a utility to improve their productivity, and any benefits to customers are deferred. The requirement for a custom index ensures that benefits are shared immediately with customers through productivity commitments.

If a utility proposes an earnings sharing mechanism as its mechanism to protect customers against excess earnings, it should be based on overall earnings at the end of the term, not an assessment of earnings in each year of the term, consistent with the approach to limiting mid-term updates.

If a Custom IR application does not meet all of these requirements, the OEB may impose a reduced term, reject the application or determine that an application is incomplete and will not be processed until the requirements are met.

[17] This policy was reaffirmed in the RRFE Report.
[18] *Report of the Board: Rate-Making Associated with Distributor Consolidation*, March 26, 2015

mandated by the CNSC or that could otherwise increase safety or environmental risks or the risk of non-compliance with legislated requirements.

The proposed stretch reductions are in addition to efficiencies and performance improvements within the company's business planning processes. OPG continually strives to improve the company's performance and operational efficiency where it can do so safely within operational requirements (e.g., CNSC requirements) and without affecting reliability. Through the gap-based nuclear business planning process described in Ex. F2-1-1, OPG develops initiatives to meet these goals. The performance initiatives incorporated in the business planning process and the corresponding performance and operational efficiency improvements are reflected in the forecast expenditures in this application.

As noted above, the stretch factor applies to approximately 75% of OPG's nuclear OM&A. While OPG does not expect to find material efficiencies in the remaining 25% during the term of this application, it will seek to improve performance and reduce costs where it can responsibly do so.

3.2.1. Derivation of Proposed Stretch Factor

OPG proposes a stretch factor of 0.3%, which is based on the methodology used by the OEB to set electricity distribution rates. Under the RRFE, distributors may be subject to a range of stretch factors from 0% to 0.6%,[34] based on their benchmark performance. OPG has adopted the OEB's range in its proposed ratemaking frameworks for both hydroelectric and nuclear generating facilities.

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[34] Under the RRFE, electricity distributors are assigned to one of five performance cohorts based on their forecast costs relative to econometrically predicted benchmark costs. Based on their determined performance cohort, distributors are assigned a stretch factor of 0%, 0.15%, 0.3%, 0.45% or 0.6%..

As set out in the 2015 Nuclear Benchmarking Report, Darlington's Total Generating Cost per MWh performs in the top quartile, and the Pickering facility is in the fourth quartile.[35] OPG used a production-weighted average to determine a combined stretch factor value of just below 0.3%. Chart 9 illustrates the derivation of OPG's proposed stretch factor, based on the most recent OEB-approved nuclear production forecast.

Chart 9 – Derivation of Nuclear Stretch Factor

Input	Value
OEB-approved 2015 Darlington production (TWh)	25.0
OEB-approved 2015 Pickering production (TWh)	21.6
Darlington stretch factor (based on benchmark performance)	0.0%
Pickering stretch factor (based on benchmark performance)	0.6%
Production-weighted average stretch factor	0.3%

OPG has reduced the requested payment amounts by 0.3 per cent of the company's nuclear Base OM&A and allocated corporate support OM&A beginning in 2018. The amounts shown in Ex. F2-2-1 reflect the full forecast revenue requirement. The stretch reduction is applied when determining the company's payment amounts in Ex. I1-3-1.

In order to emulate the effect of the stretch-factor in the OEB's 4GIRM price-cap framework, OPG has calculated annual stretch reductions such that prior years' reductions are maintained (i.e., reductions to revenue requirement made in 2018 are carried forward to subsequent

[35] OPG has used its OEB-approved total generation cost benchmarking performance to determine where the company's nuclear division should fall on the OEB's range of stretch factors. OPG's 2015 Nuclear Benchmarking Report is filed at Ex. F2-1-1, Attachment 1. The Total Generating Cost benchmarking results are on p. 65.

years, on the presumption that the company should be incented to find additional savings each year). Reductions are proposed beginning in 2018, with additional reductions in 2019, 2020, and 2021. This mirrors the operation of the stretch factor under 4GIRM.

Chart 10 shows the product of applying the 0.3% stretch factor to Base OM&A and allocated corporate support OM&A.

Chart 10 – Stretch Reduction Amounts

($M)	**2018**	**2019**	**2020**	**2021**
Base & Corporate Support OM&A	1,663.2	1,691.1	1,709.7	1,730.4
Stretch Factor	0.3%	0.3%	0.3%	0.3%
Annual Stretch Reduction to Nuclear Revenue Requirement	**5.0**	**10.1**	**15.2**	**20.4**
Base & Corporate Support OM&A Used to Determine Payment Amounts	**1,658.2**	**1,681.0**	**1,694.5**	**1,710.0**

The total reduction over the term of the application is $50.6M. Although the 0.3% stretch reduction is constant, the “snow plow” effect of maintaining prior years’ reductions means that the $20.4M reduction in 2021 is a 1.2% reduction to that year’s stretch-eligible OM&A, or a 0.9% reduction to total nuclear OM&A.

This stretch reduction is incremental to the performance improvements required to achieve OPG’s business plan. Customers will benefit from these “up-front” budget reductions, and OPG will bear the risk of any shortfall.

3.2.2. Productivity Factor is Not Applicable

OPG is not proposing a nuclear industry productivity adjustment as part of the proposed X-factor. The nature and scale of capital work planned for the IR period mean that past productivity trends would not be a reasonable indicator of predicted productivity for OPG during the IR period.

November 2015

ONTARIO POWER GENERATION

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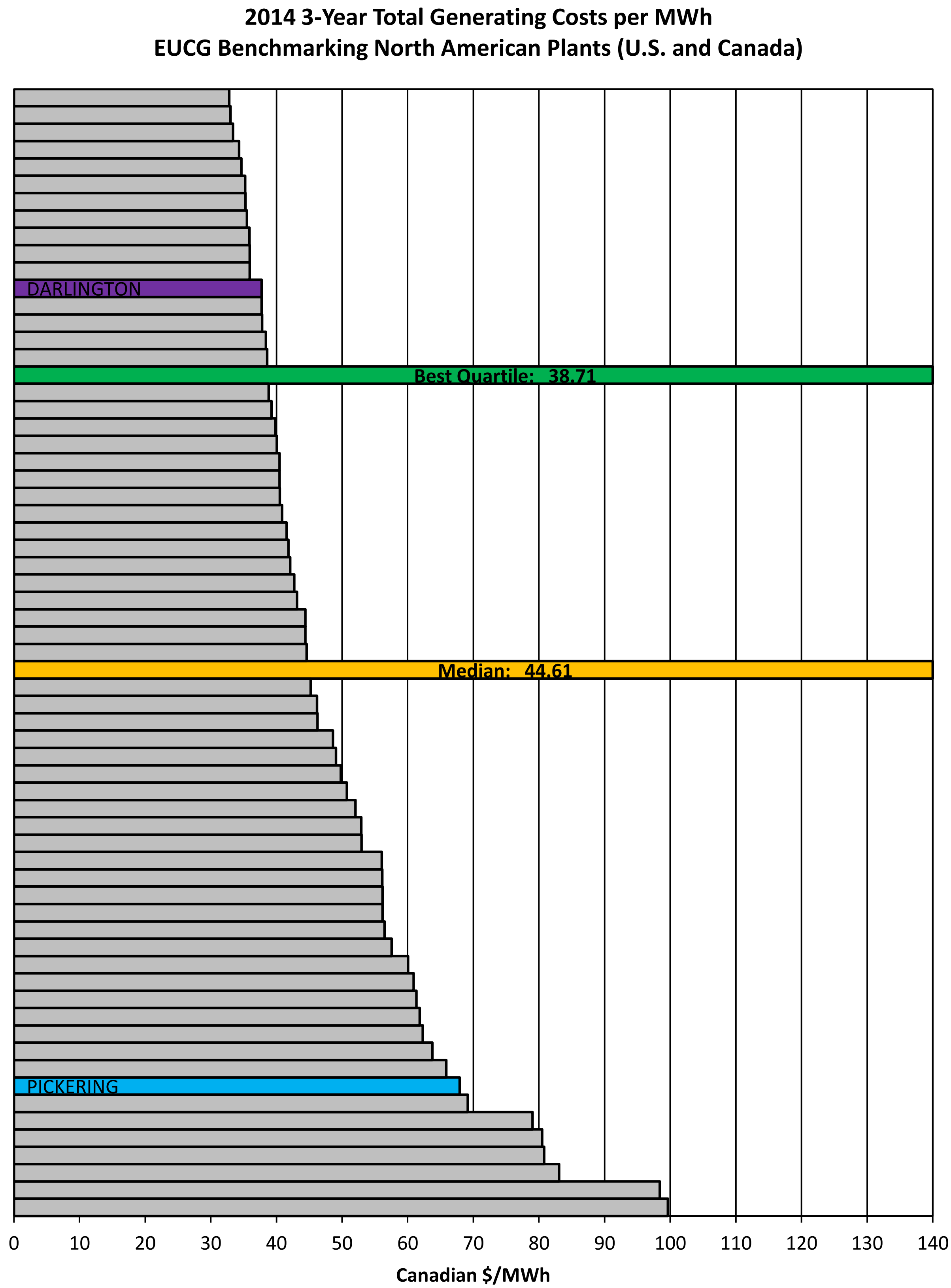
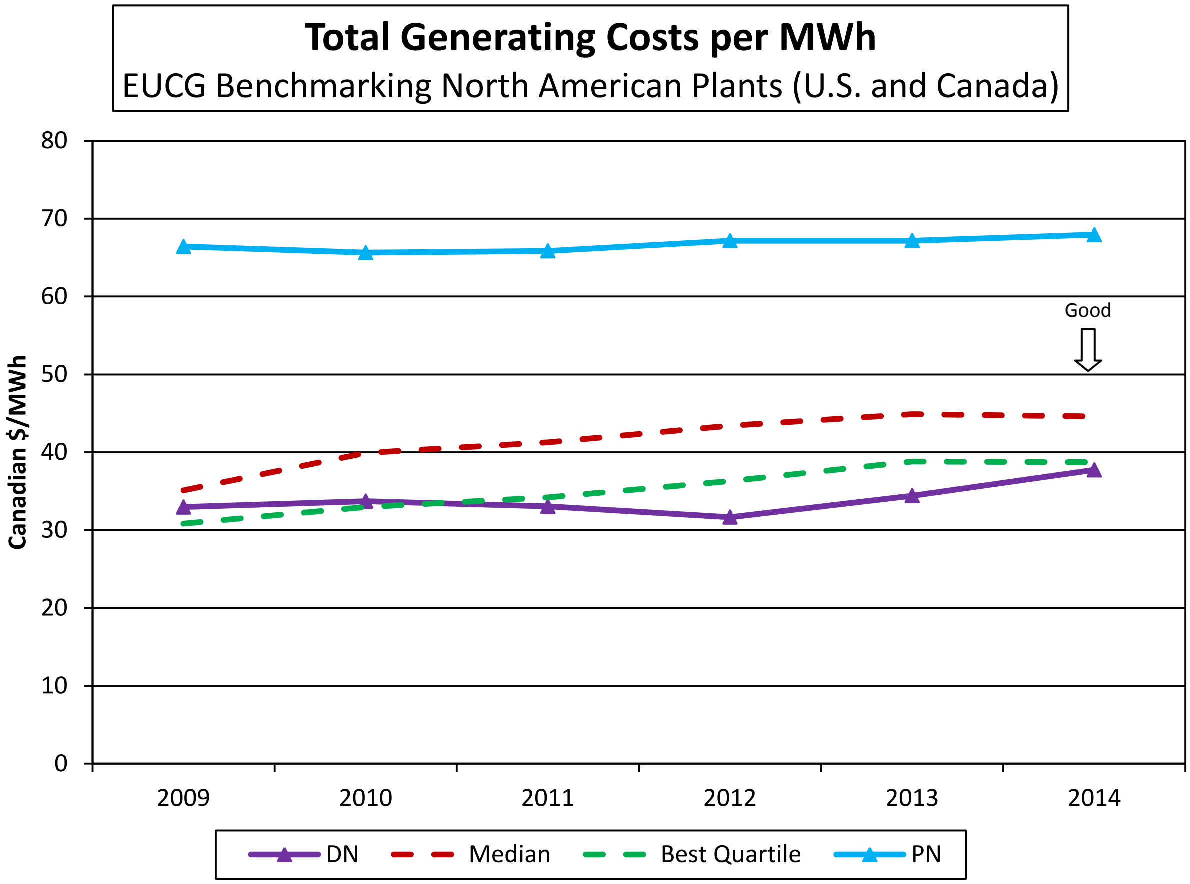
2015 NUCLEAR BENCHMARKING REPORT

Non-Confidential – For General Release

Nuclear Finance – Business Planning and Benchmarking

3-Year Total Generating Cost per MWh




Total Generating Costs per MWh
EUCG Benchmarking North American Plants (U.S. and Canada)
Canadian $/MWh
80
70
60
50
40
30
20
10
0
2009
2010
2011
2012
2013
2014
Good
DN
Median
Best Quartile
PN

Observations – 3-Year Total Generating Cost per MWh (All North American Plants)

2014 (3-Year Rolling Average)

- The best quartile level for Total Generating Cost per MWh (TGC/MWh) among North American EUCG participants was $38.71/MWh while the median level was $44.61/MWh.
- Darlington achieved best quartile performance with a Total Generating Cost of $37.73/MWh.
- Pickering Total Generating Cost was $67.93/MWh, worse than the median of $44.61/MWh.

Trend

- Best quartile and median TGC/MWh have escalated from 2009 to 2014. The best quartile cost rose by $7.88/MWh while the median cost rose by $9.50/MWh.
- Darlington's costs trended downward from 2010 to 2012 but have increased in both 2013 and 2014. Darlington's TGC/MWh increased by 9.6% in 2014 from 2013 levels. Even with this increase Darlington has maintained its best quartile ranking from 2011. The growth in Darlington's TGC/MWh was $4.77/MWh compared to a $7.88/MWh increase in the industry best quartile over the 2009-2014 review period.
- Over the 2009-2014 review period, Pickering maintained a relatively stable cost profile, experiencing a compound annual growth rate of only 0.5% while the industry median quartile experienced a growth rate of approximately 4.9% over the same period.

Factors Contributing to Performance

- For technological reasons, Fuel Costs per MWh is an advantage for all CANDUs and the OPG plants performed within the best quartile.
- Non-Fuel Operating Cost per MWh, for all OPG plants as a whole, yielded results that are worse than median for 2014 compared to the North American EUCG panel.
- OPG Capital Costs are below industry levels. Capital expenditures reported by the peer group include costs either not incurred by OPG due to technological differences or have been incurred by the peer group to a larger extent than OPG.

ONTARIO POWER GENERATION NUCLEAR

2016 Nuclear Benchmarking Report

OPG Confidential – Internal Use Only

Nuclear Finance – Business Planning and Benchmarking

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Exhibit L, Tab 6.2
Schedule 15 SEC-063
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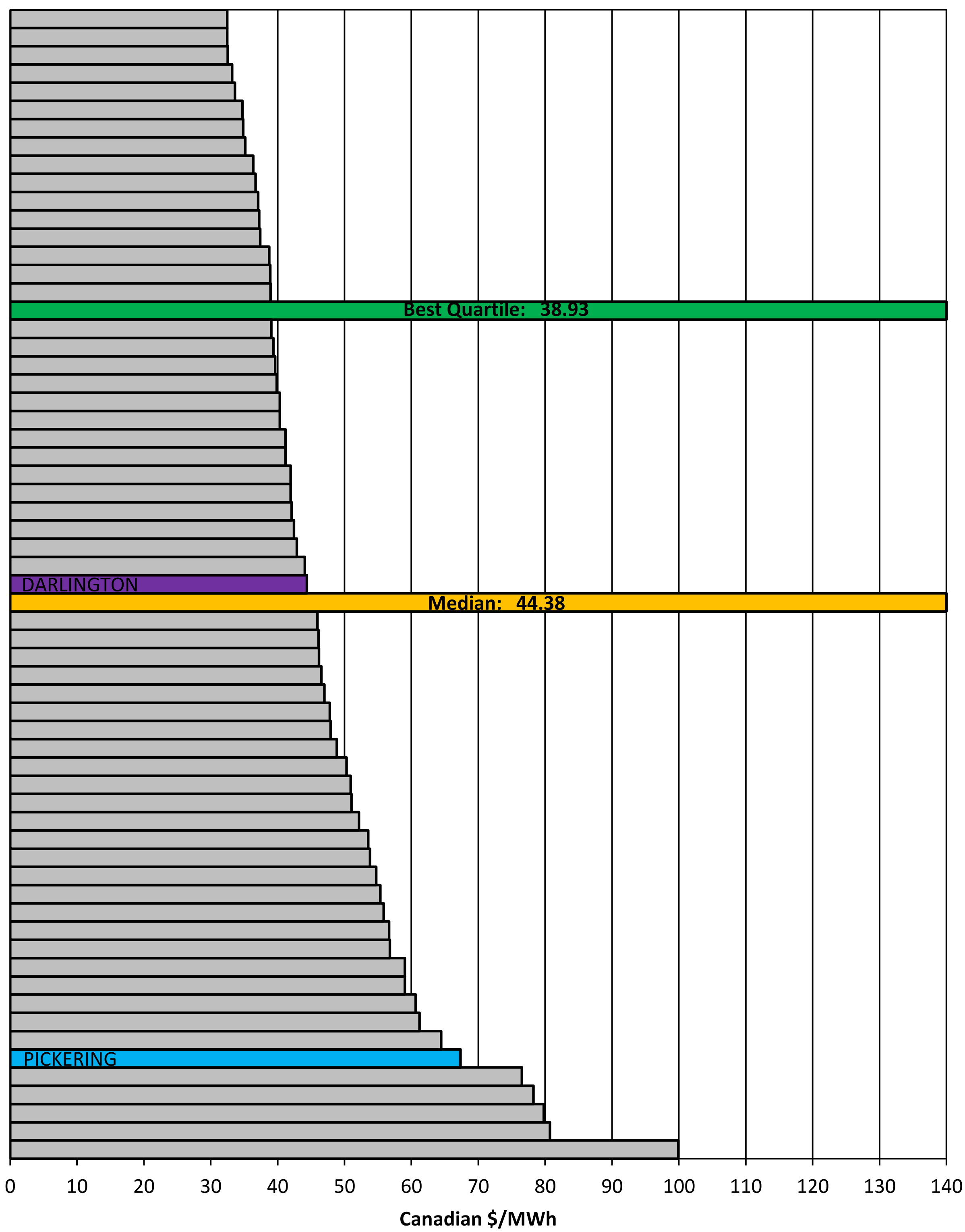
3-Year Total Generating Cost per MWh

2015 3-Year Total Generating Costs per MWh
EUCG Benchmarking North American Plants (U.S. and Canada)



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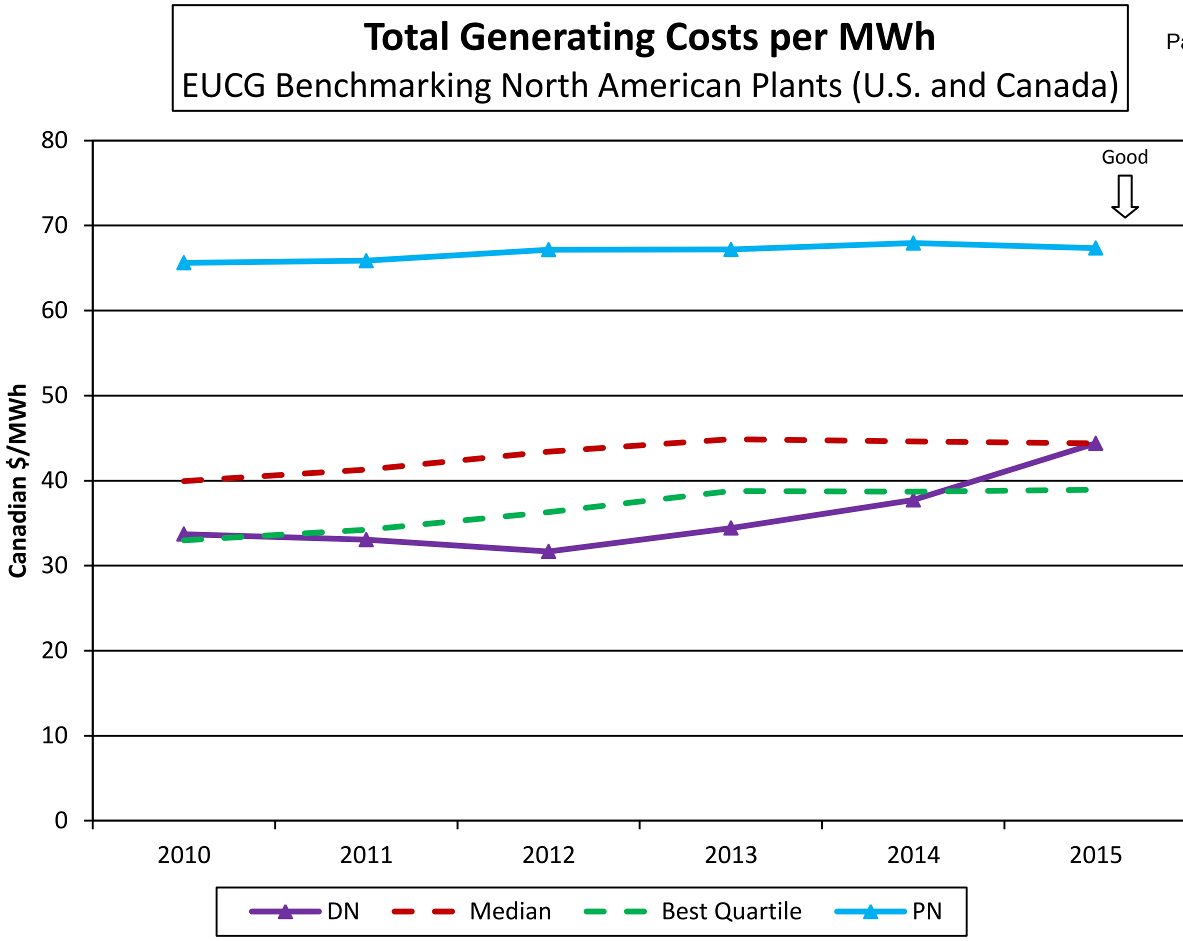

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Observations – 3-Year Total Generating Cost per MWh (All North American Plants)

2015 (3-Year Rolling Average)

- The best quartile level for Total Generating Cost per MWh (TGC/MWh) among North American EUCG participants was $38.93/MWh while the median level was $44.38/MWh.
- Darlington TGC/MWh was $44.38/MWh, equal to the median of $44.38/MWh.
- Pickering TGC/MWh was $67.36/MWh, worse than the median of $44.38/MWh.

Trend

- Over the 2010 to the 2015 period, the best quartile cost rose by $5.95/MWh while the median cost rose by $4.45/MWh.
- Darlington rose by $10.66/MWh and Pickering rose by $1.73/MWh.
- Both best quartile and median levels increased over the 2010-2015 period with a compound annual growth rate of 3.4% for best quartile and 2.1% for median.
- Darlington annual compound growth rate was 5.7%, higher than the median annual compound growth rate. Pickering was relatively flat with an annual compound growth rate of 0.5%.

Factors Contributing to Performance

- For technological reasons, Fuel Costs per MWh is an advantage for all CANDUs and the OPG plants performed within the best quartile.
- Non-Fuel Operating Cost per MWh, for all OPG plants, yielded results that are worse than the median for the most recent data point compared to the North American EUCG panel.
- OPG Capital Costs are below industry levels. Capital expenditures reported by the peer group include costs for life extension, reactor head replacement, steam generator replacement, uprates, and spent fuel storage. These are costs not incurred by OPG to the extent as its peers.

Darlington

- The 3-Year Rolling Average for Darlington from 2014 to 2015 rose $6.65/MWh. The primary drivers at Darlington were lower generation (4,998 GWh) and higher total costs of approximately $319M. The higher total costs were primarily attributable to higher Operating, Maintenance & Administrative (OM&A) costs of $212M and Capital costs of $129M, partially slightly offset by lower Fuel Costs of $22M .
- Lower generation at Darlington was primarily due to higher planned outage days and increased forced outages. Outage days at Darlington increased by 234 days for 2015 period versus 2014 mainly due to the Darlington Vacuum Building Outage in 2015.

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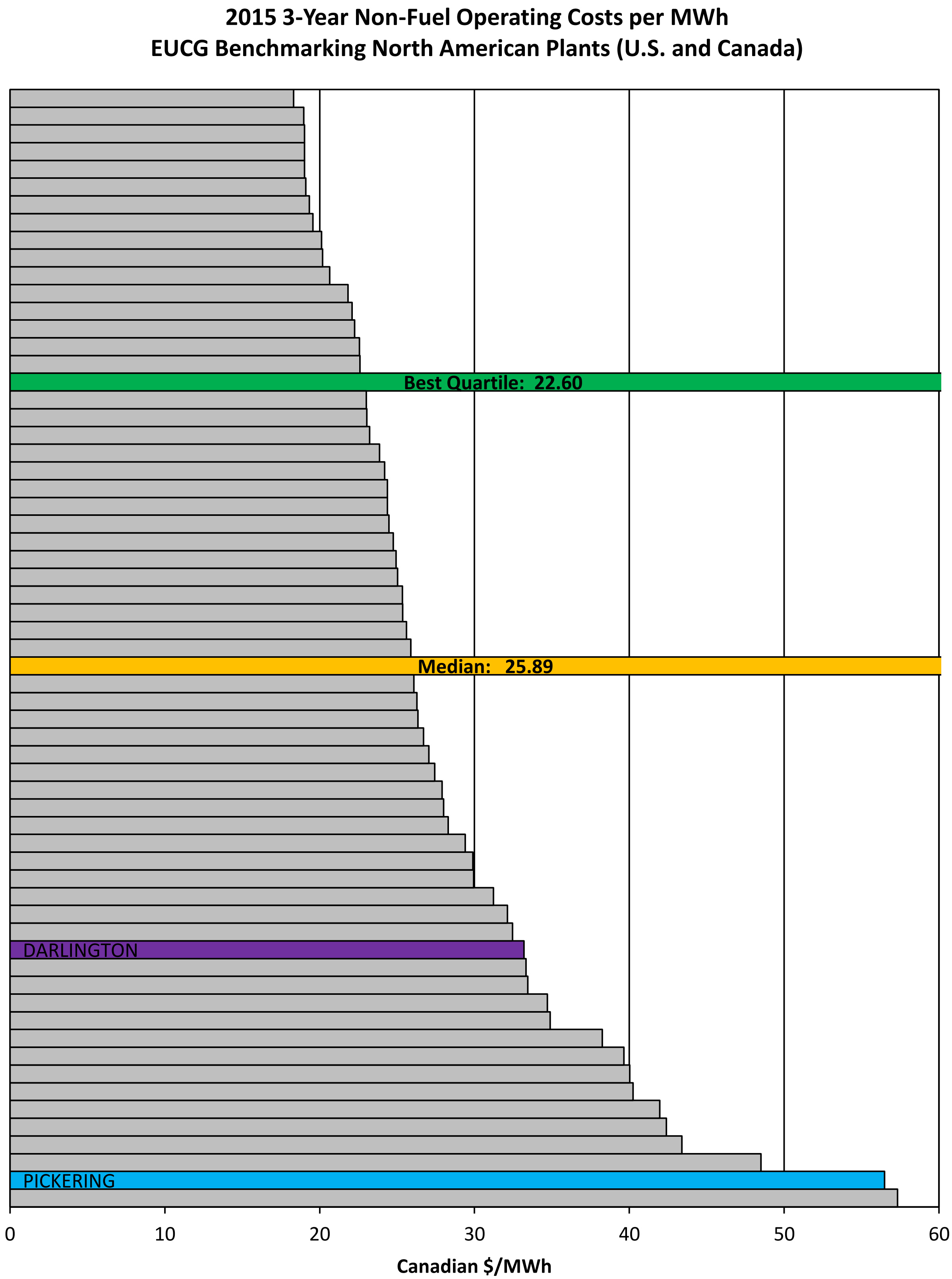
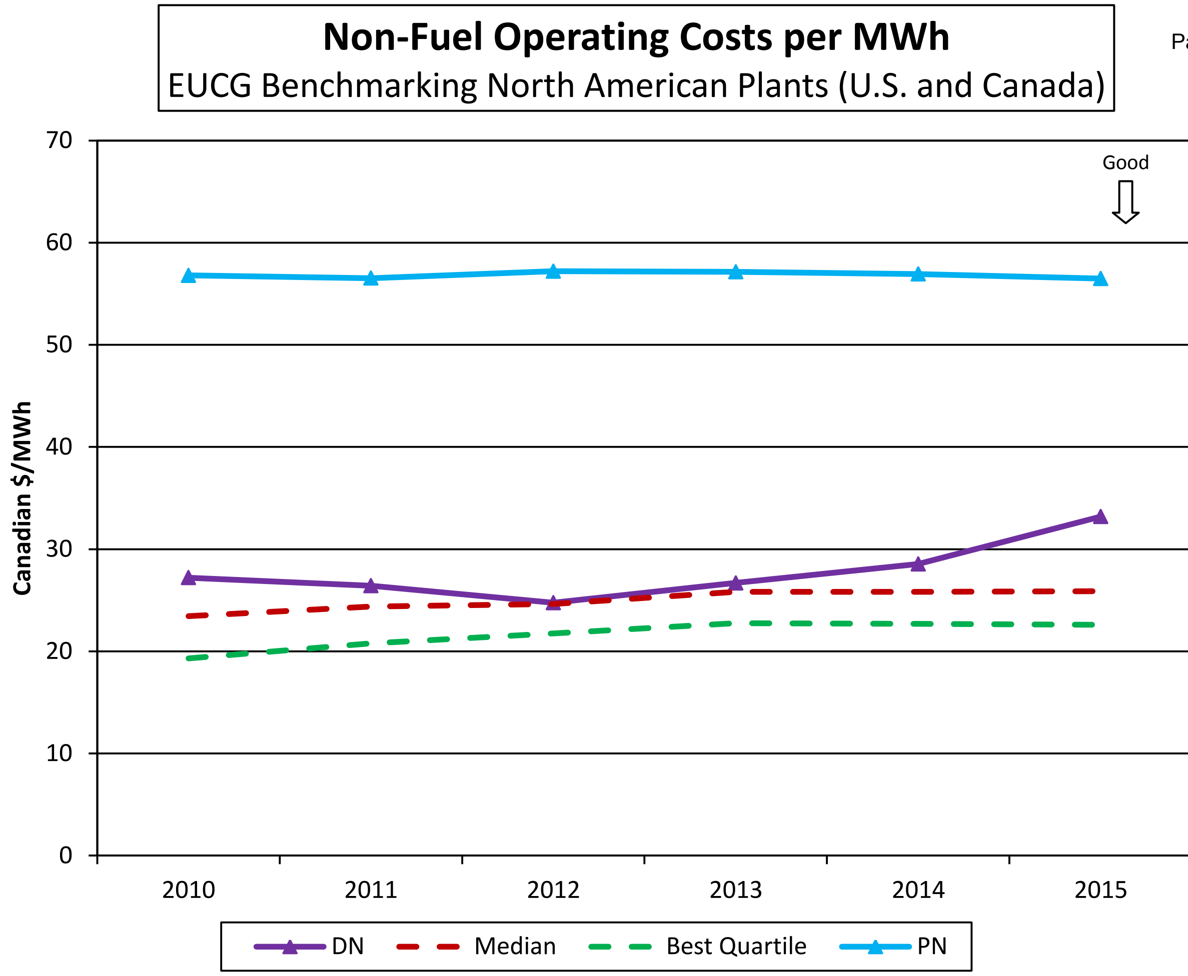
3-Year Non-Fuel Operating Cost per MWh




Non-Fuel Operating Costs per MWh
EUCG Benchmarking North American Plants (U.S. and Canada)
Canadian $/MWh
70
60
50
40
30
20
10
0
Good
2010
2011
2012
2013
2014
2015
DN
Median
Best Quartile
PN

Observations – 3-Year Non-Fuel Operating Cost per MWh (All North American Plants)

2015 (3-Year Rolling Average)

- Best quartile plants had Non-Fuel Operating Costs per MWh (NFOC/MWh) at or below $22.60.
- The median plant level threshold was $25.89/MWh.
- Compared to North American EUCG plants, the Non-Fuel Operating Costs per MWh of all participating Canadian CANDU plants are worse than industry median performance.
- Darlington's costs, at $33.19/MWh, were $10.59/MWh higher than best quartile and $7.30/MWh higher than the median.
- Pickering's costs, at $56.49/MWh, were $33.89/MWh higher than best quartile and $30.60/MWh higher than median.

Trend

- Both best quartile and median levels increased over the 2010-2015 period with a compound annual growth rate of approximately 3.2% for the best quartile and approximately 2.0% for the median.
- Darlington annual compound growth rate was 4.1% and Pickering's effectively did not change.
- Pickering 3-yr NFOC/MWh increased from 2010 ($56.79/MWh) to 2012 ($57.21/MWh) then decreased by 2015 ($56.49/MWh). Please see 2015 TGC per MWh discussion regarding total Pickering costs and production. Higher electricity production levels are largely due to the successful implementation of equipment reliability program improvement initiatives and strategic investments to resolve degraded or obsolete equipment issues which helped reduce Pickering's forced loss rate.
- Pickering's 3-yr NFOC/MWh had a slight reduction from 2010 to 2015 as compared to the annual compound growth rates of 3.2% for best quartile and 2.0% for median levels due to slightly lower costs and higher production.
- Pickering's annual Non-Fuel Operating Cost, over the 2010-2015 review period, is being managed through the continuous pursuit of efficiency improvements enabled by initiatives such as the amalgamation of the Pickering A and Pickering B stations into one Pickering site. The company-wide business transformation project launched in 2011 is also helping streamline, eliminate and reduce work to leverage attrition profiles while sustaining safety and reliability performance excellence.
- Over the 2010-2015 review period, Darlington's Non-Fuel Operating Cost increased from 2010 ($27.22/MWh) to 2015 ($33.19/MWh). Please see 2015 TGC per MWh discussion regarding total Darlington costs and production.
- Darlington's 3-yr NFOC/MWh had an annual compound growth rate of 4.1% from 2010 to 2015 as compared to 3.2% for best quartile and 2.0% for median levels. The 2015 increase in Darlington's 3-yr NFOC/MWh from 2014 is due to primarily to lower generation from the Darlington VBO and higher FLR, and higher OM&A spending.

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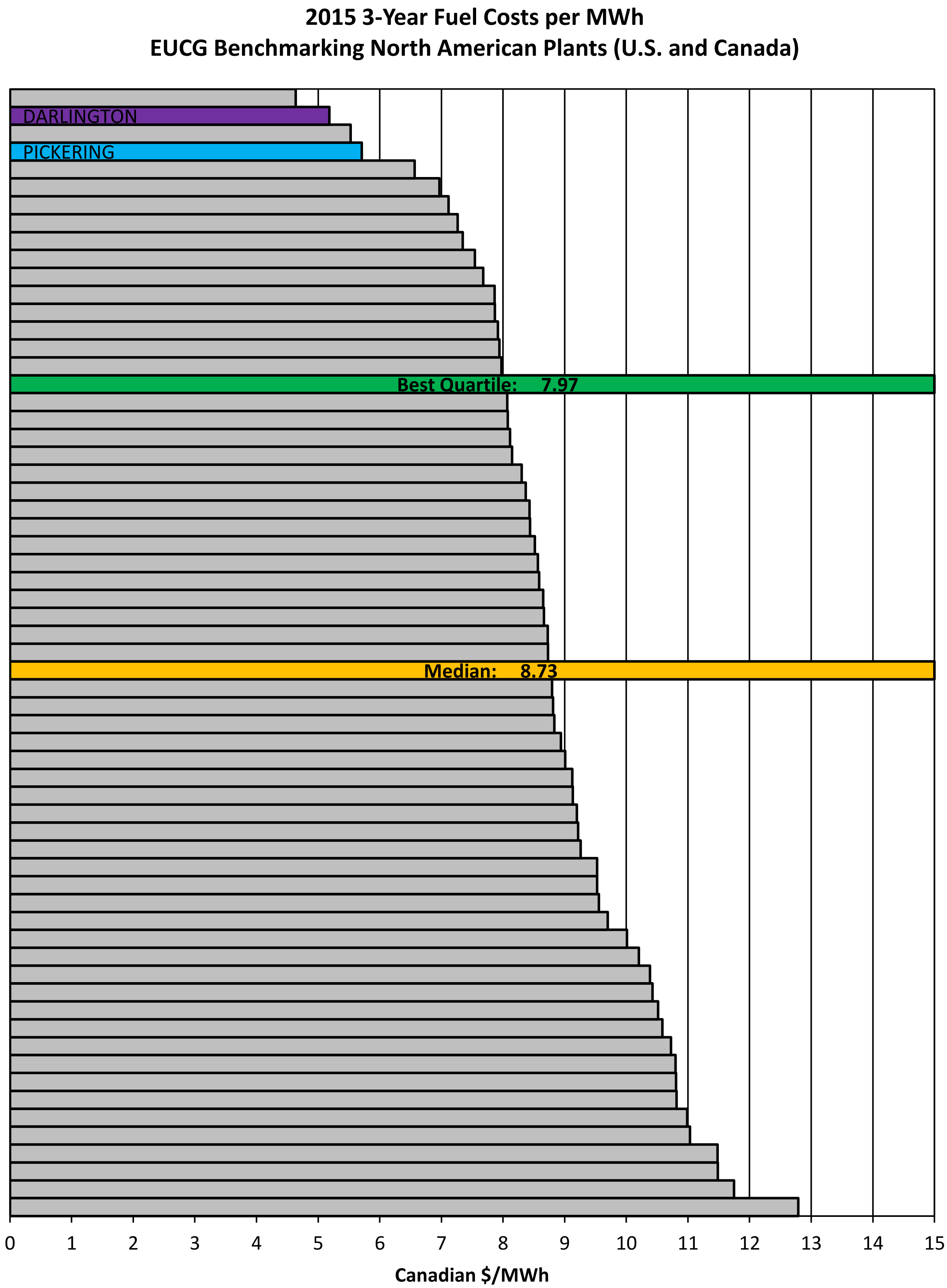
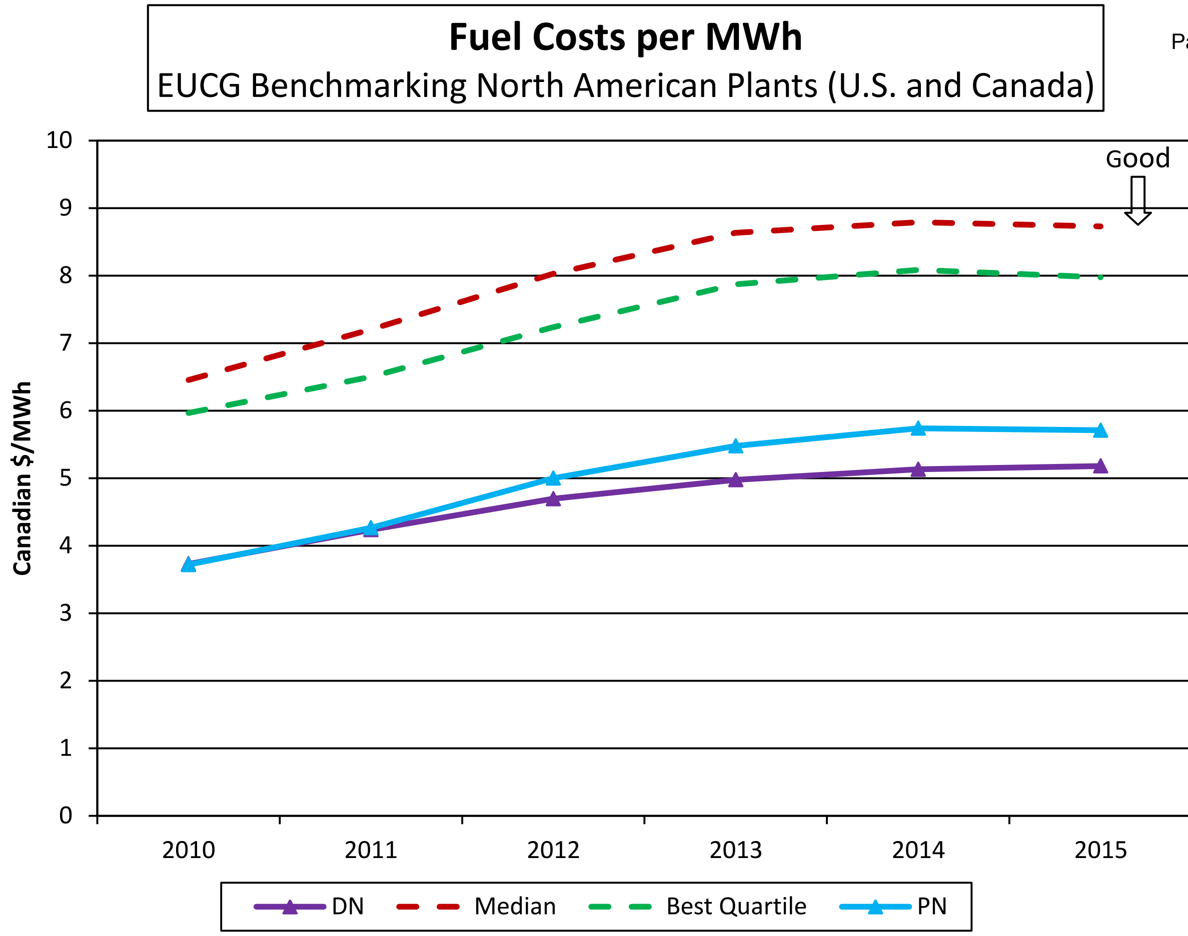
Factors Contributing to Performance – 3-Year Non-Fuel Operating Cost per MWh (CONT'D)

Factors Contributing to Performance

- Performance in Non-Fuel Operating Cost per MWh drives the majority of OPG's financial performance. The most significant performance gap drivers are CANDU technology, capability factor, station size, age of the plant, corporate cost allocations and capitalization policy. The biggest drivers are further expanded below:
  - The 'capability factor' driver is related specifically to generation performance of the station in relation to the overall potential for the station (results are discussed under the Reliability section within the Rolling Average Unit Capability Factor metric).
  - The 'station size' driver is the combined effect of number of units and size of units which can have a significant impact on plant cost performance.
  - The 'CANDU technology' driver relates specifically to the concept that CANDU technology results in some specific cost disadvantages related to the overall engineering, maintenance, and inspection costs. While OPG's ten nuclear units are all CANDU reactors, they reflect three generations of design philosophy and technology which impacts the extent and nature of operations and maintenance activity. In addition, this factor is influenced by the fact that CANDU plants have less well-developed user groups to share and adopt competitive advantage information, than do longer-established user groups for Pressurized Water Reactors (PWR) and Boiling Water Reactors (BWR). Though quantification of CANDU technology impact to cost remains most difficult of all drivers, a staff benchmarking analysis recognized a significant reduction in the gap between OPG staff levels and the industry benchmark. OPG undertook a staffing study through a third-party consultant which concluded that technology, design and regulatory differences exist between CANDU and PWR reactor units and that such factors drive staffing differences. The study established that CANDU technology was a contributor to explaining higher staffing levels for CANDU versus PWR plants which also contributed to OPG's performance in Non-Fuel Operating Cost.
  - The 'corporate cost allocations' driver relates directly to the allocated corporate support costs charged to the nuclear group.
  - Capitalization policy can be an indirect contributing factor when benchmarking Non-Fuel Operating Cost due to variations in "repair vs. replace strategies.", i.e. a strategy to repair versus replace will increase non fuel operating cost versus option to replace. The impact of differing capitalization policies is removed when looking at Total Generating Cost per MWh (i.e., the sum of Non-Fuel Operating Cost, Fuel Cost, and Capital Cost).

3-Year Fuel Cost per MWh




Fuel Costs per MWh
EUCG Benchmarking North American Plants (U.S. and Canada)
Canadian $/MWh
Good
10
9
8
7
6
5
4
3
2
1
0
2010
2011
2012
2013
2014
2015
DN
Median
Best Quartile
PN

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Observations – 3-Year Fuel Cost per MWh (All North American Plants)

2015 (3-Year Rolling Average)

- Fuel Cost per MWh for all Canadian CANDU plants are better than the best quartile threshold ($7.97/MWh) for the panel of North American EUCG plants.
- The two OPG plants ranked as the top four lowest fuel cost plants in the North American panel with Darlington ($5.18/MWh) at second and Pickering ($5.71/MWh) at fourth.

Trend

- The best quartile 3-year Fuel Cost per MWh has remained flat over 2014 and 2015.
- From 2010 to 2012, Fuel Cost per MWh for all OPG plants had been rising and has since stabilized over the last three years, a trend similarly experienced by the nuclear industry. The rate of increase in the Fuel Cost per MWh has moderated since 2012, due primarily to lower input uranium costs offset by rising used fuel storage and disposal costs, which have increased well above the rate of inflation from 2014 to 2015.
- The Darlington Generating Station would rank the lowest among the CANDU plants in the peer panel ranked group if used fuel storage and disposal provision costs were excluded from the calculation with a 3-year rolling average fuel cost per MWh of $4.20/MWh. Similarly, Pickering would rank second with an average 3-year rolling average fuel cost per MWh of $4.25/MWh.

Factors Contributing to Performance

- Fuel costs, primarily driven by the technological differences in CANDU technology, are lower for OPG than all North American Pressurized Water Reactors or Boiling Water Reactors (PWR/BWR) reactors as CANDUs do not require enriched uranium like BWRs and PWRs. This provides a significant advantage for OPG and other CANDUs in this cost category.

Best quartile fuel cost performance noted above is due to the following factors:

- Uranium fuel costs: Raw uranium is processed directly into uranium dioxide to make fuel pellets, without the cost and process complexity of enriching the fuel as required in light water reactors. Fuel costs also include transportation, handling and shipping costs.
- Reactor core efficiency: CANDU is the most efficient of all reactors in using uranium, requiring about 15% less uranium than PWRs for each megawatt hour of electricity.

Ontario Energy Board
Commission de l’énergie de l’Ontario

DECISION AND ORDER

EB-2014-0116

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

Application for electricity distribution rates effective from May 1, 2015 and for each following year effective January 1 through to December 31, 2019

BEFORE: **Christine Long**
Presiding Member

Ken Quesnelle
Vice Chair and Member

Cathy Spoel
Member

December 29, 2015

The OEB considers the asset price inflation value used by PEG to be more appropriate. The 2.0% annual growth rate is more closely aligned to the value used by the OEB as the annual inflation factor.

Similarities between the Experts

There were also areas where the experts agreed. While they disagreed on the rate of increase, both experts did agree that Toronto Hydro's costs are increasing at a faster pace than the US comparators'.

b) Application of the Stretch Factor to Capital

Some parties argued that a stretch factor should be applied to capital as well as OM&A costs. They pointed out that the OEB has always applied stretch factors to total costs rather than just OM&A costs. Others did not favour this approach, and submitted that the capital budget should be reduced or it should be linked to performance metrics instead.

Toronto Hydro argued that the stretch factor should not be applied to capital (the C factor) as productivity is sufficiently embedded in Toronto Hydro's capital plan and the rate framework.

Findings

The OEB has consistently applied stretch factors to total costs in order to incent productivity in both the areas of capital expenditure and OM&A. The OEB finds no compelling reason to depart from this approach. While the Application put forward by Toronto Hydro may be a custom application, one of the key aspects of the OEB's RRFE is the requirement to continue to make productivity improvements. As discussed later in this Decision, the OEB is concerned that the Application does not contain enough productivity incentives. Application of the stretch factor to the C factor is one way to remedy this deficiency.

The Use of Benchmarking

SEC argued that custom benchmarking is a critical aspect of a Custom IR application and that any distributor seeking greater increases in revenue requirement or rate than the norm should be in a position to file benchmarking evidence consistent with those greater levels. If they cannot, their additional spending requirements cannot be supported.

Chart 4
Operational and FinancialTargets

Benchmarking Indicators	WANO Max NPI	Best Quartile+	Median Quartile+	Pickering – Annual Targets			Darlington – Annual Targets		
				2016	2017	2018	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 ($/Net MWh)++		24.48	27.88	N/A	N/A	N/A	33.84	35.36	33.69
Non-Fuel Operating Cost per MWh ($/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)

CME Interrogatory #3

Issue Number: 11.3
Issue: Is OPG's approach to incentive rate-setting for establishing the nuclear payment amounts appropriate?

Interrogatory

Reference:
Ref: Exhibit A1, Tab 3, Schedule 1, page 6 of 12

OPG proposes to apply the stretch factor to approximately $1.7 billion, or approximately 75% of OPG's total nuclear OM&A in each year of the application. Please explain why the stretch factor is being applied to only 75% of OPG's total nuclear OM&A, and not to 100% of OPG's total nuclear OM&A in each year of the application

Response

OPG's Nuclear stretch factor proposal and the rationale that supports it are detailed in section 3.2 of Ex. A1-3-2, pages 28 to 33.

VECC Interrogatory #49

Issue Number: 11.3
Issue: Is OPG's approach to incentive rate-setting for establishing the nuclear payment amounts appropriate?

Interrogatory

Reference:
Reference: A1/T3/S2/pg.30-31

a) For the 25% of costs which OPG will not apply the stretch factor please identify all the individual area (e.g. emergency preparedness) and the total annual test year costs in those areas.

b) For each area please give the portion of costs that are compensation and benefit related.

c) OPG notes that these are areas in which it will not, or cannot compromise its commitments. However, it does not explain why it is not possible to execute its responsibilities in these areas in a more efficient manner. For each of the areas identified please explain the reason no efficiencies can be found while still carrying out the prescribed duties.

Response

a) A summary of nuclear operating cost information is provided in Ex. F2-1-1 Table 1. Of the costs identified in Table 1, the stretch factor applies to Nuclear Base OM&A and Corporate Support OM&A. The major operational components of the remaining Nuclear OM&A are Project OM&A (detailed provided in Ex. F2-3-1) and Outage OM&A (detailed provided in Ex. F2-4-1). The costs in these areas are not budgeted on the basis of individual areas (like emergency preparedness). Project OM&A is comprised of "temporary, unique endeavour[s] undertaken outside the routine base activities of the normal work program" (Ex. F2-3-1, p. 1, lines 23-24). Outage OM&A costs are tied to specific outages, and "vary year over year depending on the number and scope of outages and therefore cannot be trended over time" (Ex. F2-4-1, p. 1, lines 7-8).

   The other material components of Nuclear OM&A to which the stretch factor does not apply are:
   - Darlington Refurbishment OM&A (details provided in Ex. F2-7-1)
   - Centrally Held and Other Costs (detailed provided in Ex. F4-4-1)
   - Asset Service Fees (detailed provided in Ex. F3-2-1)

b) Please see Chart 1 below.

Chart 1: Labour Component of Costs Excluded from Nuclear Stretch Factor ($M)

Cost Component	2018	2019	2020	2021	Reference
Outage OM&A					
Labour	124.3	121.4	88.6	50.6	
Total Outage	393.8	415.3	394.4	308.5	F2-4-1 Table 2
Labour % of Total	32%	29%	22%	16%	
Project OM&A					
Labour	26.7	26.5	25.4	20.7	
Total Projects	109.1	100.1	100.2	86.8	F2-3-1 Table 1
Labour % of Total	24%	26%	25%	24%	

There are no material labour costs associated with Darlington Refurbishment OM&A, and Asset Service Fees. The centrally-held compensation-related costs primarily consist of centrally-held pension and OPEB accrual costs (Ex. F4-4-1 Table 3, line 1), performance incentives (Ex. F4-4-1 table 3 line 5) and a negative adjustment that converts pension and OPEB costs from an accrual to a cash basis (Ex. F4-4-1 table 3, line 2). On a net basis, these amounts result in annual reductions in costs of approximately -$48.3M in 2018, -$34.2M in 2019, -$38.2M in 2020, and -$26.3M in 2021.

c) The question appears to misinterpret the referenced evidence. At the reference, OPG states that Base OM&A (which is already subject to the proposed stretch factor) “includes several critical, regulated functions including safety, emergency preparedness, inspections, operations and maintenance” that OPG will not compromise, despite the fact that the associated costs <u>are subject to the stretch factor</u>. The necessary effect of consistent spending in these areas is to put additional pressure on OPG to find efficiencies in other nuclear costs.

EP Interrogatory #2

Issue Number: 1.3
Issue: Is the overall increase in nuclear payment amounts including rate riders reasonable given the overall bill impact on customers?

Interrogatory

Reference:
Reference: Exhibit A1, Tab 3, Schedule 2, page 33

OPG states that it is "not proposing a nuclear industry productivity adjustment," as the "nature and scale of the capital work planned for the IR period mean that productivity trends would not be a reasonable indicator of predicted productivity for OPG during the IR period."

Can OPG explain why a productivity factor couldn't be used for other work unrelated to the Darlington Refurbishment Project?

Response

The above statement applies generally and equally to Pickering and Darlington. Both facilities are undertaking programs intended to refurbish or extend operations. These programs involve incremental investments that will impact operations at both facilities, such that productivity trends associated with Nuclear operations during the 2017-2021 period will be substantially different from those in the historic period on which any total factor productivity analysis would be derived.

In this context – one in which operations at both facilities will be materially different from the past – a retrospective productivity factor would not be appropriate for setting rates for OPG.

Numbers may not add due to rounding.

Table 1

Production Forecast Trend - Nuclear (TWh)

Line No.	Prescribed Facility	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)
1	**Darlington NGS**	25.1	28.0	23.3	26.0	19.0	19.3	19.7	17.7	16.6
2	**Pickering NGS**	19.6	20.1	21.2	20.8	19.1	19.2	19.4	19.6	18.8
3	**Total**	44.7	48.1	44.5	46.8	38.1	38.5	39.0	37.4	35.4

SEC Interrogatory #1

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

Interrogatory

Reference:
The application proposes substantial increases in the prices to be charged for OPG generation in the next decade and beyond, particularly from the nuclear facilities. Please provide a detailed analysis of the OPG's strategy to deal with potential demand destruction as the cost of OPG generation from its nuclear facilities, increases. Please provide all forecasts, estimates, or other future-looking documents that consider:

a. The price levels at which OPG generation becomes uncompetitive,

b. The price levels at which customers start to exit the grid to avoid OPG generation costs,

c. The numbers of customers, kwh volumes, and capacity requirements that will cease to rely on OPG generation at various price levels, or

d. The options available to the OPG to avoid demand destruction and its recursive price impacts.

Response

OPG has not analyzed whether demand may be reduced as a result of changes in the company's nuclear payment amounts, nor is it aware of any analyses indicating such reductions are likely. OPG has not developed a strategy to address this hypothetical issue, and does not have any documents that are responsive to the requests in this question.

OPG's Nuclear payment amounts are only one of several factors that affect the price of electricity in Ontario. It would be inaccurate to equate "OPG generation" with the price of electricity in the IESO-controlled market. In fact, OPG notes that its generation actually helps to moderate the overall commodity price.

Board Staff Interrogatory #271

Issue Number: 11.7
Issue: Is OPG's proposed off-ramp appropriate?

Interrogatory

Reference:
Ref: Exh A1-3-2 page 23

In section 2.7, OPG has proposed an off-ramp mechanism pertaining to a situation whereby OPG's regulated ROE is outside of a deadband of +/- 300 basis points from its allowed ROE. In this case, a regulatory review could be initiated.

The proposal is that the regulated ROE would be determined on the basis of all rate regulated generation assets (i.e., both hydroelectric and nuclear).

a) In this application, the payment setting plans for nuclear and regulated hydroelectric generating assets will be different in terms of the economic and cost-recovery basis. Further, cost recovery for the nuclear generating assets is complicated by the proposed rate smoothing mechanism. How will the actual regulated return on equity for regulated generation assets be calculated over the 2017-2021 term plan?

b) Since the regulated return is based on both nuclear and regulated hydroelectric generation assets, would the regulatory review be on both the nuclear and hydroelectric plans?

c) While OPG labels this an "off-ramp", it indicates that the +/- 300 basis point deviation would be used to determine "whether a regulatory review may be initiated." [Emphasis added] This implies less than certainty that the off-ramp occurs.

   i. Under what conditions, beyond the 300 basis point deviation between achieved and approved returns, does OPG consider that a review and/or off-ramp would be required?

   ii. Under what conditions does OPG consider that a review and/or off-ramp would not be required even when the deviation between actual and approved regulated returns exceeds 300 basis points?

Response

a) The current methodologies used in determining return on equity (ROE) for the nuclear and regulated hydroelectric generating assets were established by the OEB in EB-2010-0008 and were subsequently applied in EB-2013-0321. OPG does not contemplate any changes to the calculation and/or annual reporting of its ROE for regulated generating assets during the IR Term.

The rate smoothing mechanism will not affect the calculation of OPG's regulated ROE during the IR Term. The OEB-approved ROE is reflected in the unsmoothed revenue requirement. The OEB will determine the amount of deferred revenue requirement to be recorded in the Rate Smoothing Deferral Account (RSDA) each year. The amount recorded in the RSDA will be recorded in income in the year it is recorded in the RSDA.

The following example provides a comparison of how OPG would calculate regulated ROE under smoothed and unsmoothed rates, assuming actual production and costs are incurred as approved:

Assumptions:
1) Unsmoothed Revenue Requirement = $100M
2) Approved Rate Base = $200M
3) Approved Common Equity Ratio = 50%
4) Approved Return on Equity @ 10% = $10M
5) Approved costs = Revenue Requirement less ROE = ($100M - $10M) = $90M
6) Deferred Revenue Requirement (RSDA Entry) = $2M
7) Approved Production = 10 TWhs
8) Unsmoothed Rate = $100M 10TWhs = $10.00 / MWh
9) Smoothed Rate = ($100M - $2M) / 10 TWhs = $9.80/MWh

ROE Calculation - Unsmoothed Rates:
$10/MWh * 10TWhs - $90M costs = $10M

ROE Calculation - Smoothed Rates:
$9.80/MWh * 10TWhs + $2M RSDA Entry - $90M costs = $10M

b) OPG's regulated ROE is calculated on a combined basis, including both regulated hydroelectric and nuclear generation lines of business. As described in Ex. A1-3-2, page 23, a regulatory review may be initiated if the achieved ROE for the regulated business (i.e. both hydroelectric and nuclear combined) varies from the ROE included in the payment amounts by more than 300 basis points.

The RRFE defines off-ramps as follows: "Each rate-setting method will include a trigger mechanism with an annual ROE dead band of ±300 basis points. When a distributor performs outside of this earnings dead band, a regulatory review may be initiated.......This approach will, in turn, allow the Board to take corrective action if required".[1]

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[1] *Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, October 18, 2012, page 11.

In order to determine whether corrective action is required, the OEB will need information on the specific circumstances of the ROE variance. As part of its reporting, OPG intends to assess the drivers of the ROE variance, and submit the assessment to the OEB with a proposal on what corrective action is required (if any). OPG's proposal would address whether an application for new rates is warranted, and, if so, whether such an application should apply to one or both technologies.

c)

i) The only proposed off-ramp is the ±300 basis points variance identified in section 2.7 of Ex. A1-3-2.

ii) OPG cannot identify all situations in which the ±300 basis points ROE threshold would be triggered, but where an off-ramp would not be required. As a hypothetical example, if OPG were to experience a substantial but short-term variance in ROE, OPG might propose that the OEB maintain the approved rate-setting methodology for the remainder of the IR term. Any proposal would depend on the specific circumstances underlying the ROE variance.

CCC Interrogatory #55

Issue Number: 11.7
Issue: Is OPG's proposed off-ramp appropriate?

Interrogatory

Reference:
Reference: Ex. A1/T3/S2/p. 23

OPG has proposed an off-ramp whereby a regulatory review will be triggered if the actual regulated ROE is outside of a dead band of +/- 300 basis points relative to the allowed ROE. Please set out in detail how OPG intends to calculate its actual ROE given the payment amounts are determined through the smoothing mechanism. What would be the dollar value of 300 basis points for each year of the rate term?

Response

For details on how OPG intends to calculate its ROE during the IR term, please see Ex. L-11.7-1 Staff-271 part a).

The dollar values of the threshold for each year of the rate term are provided in the table below:

Threshold Associated with a 300-Basis Point Off-Ramp

Line No.		2017	2018	2019	2020	2021
1	Return on Common Equity[1] ($M)	487.3	495.1	491.9	679.0	704.4
2	Return on Common Equity[1] (%)	9.19%	9.19%	9.19%	9.19%	9.19%
3	Threshold (%)	3.00%	3.00%	3.00%	3.00%	3.00%
4	Threshold ($M) (line 1 / line 2 x line 3)	159.1	161.6	160.6	221.7	229.9

1 Ex. C1-1-1 Tables 1-5, line 5, columns (c) and (d)

Board Staff Interrogatory #270

Issue Number: 11.5
Issue: Is OPG's proposed mid-term review appropriate?

Interrogatory

Reference:
Ref: Exh A1-3-3 pages 11-12

OPG states it is extremely difficult to accurately forecast OPG's annual nuclear production over a five-year period and has also stated that it has never met its own two-year forecast (as approved by the OEB in prior years). OPG profiles five uncertainties that may have an impact on production (and implicitly associated costs):

1. Public policy changes
2. Pickering extended operations
3. Execution of Darlington refurbishment program
4. Regulatory requirements and approvals
5. Aging facilities

OPG does not quantify these uncertainties. Please provide "high and low" forecasts for production and associated cost impacts for each of these uncertainties. Please use the attached spreadsheet.

Response

The mid-term review is necessary specifically because OPG cannot quantify the effects of these uncertainties on the company's production forecast. Depending on the specific circumstances, each uncertainty could have a wide range of effects on OPG's production and fuel costs, and on its capital and operating budgets.

The range of potential permutations and combinations within and between the uncertainties prohibits OPG from producing individual forecasts that would be representative of each. This unpredictability is the basis of OPG's decision to include the mid-term Nuclear production review in this application.

As described in Ex. E2-1-1, OPG has a rigorous production forecast that accounts for uncertainties to the extent possible. For example, OPG has established a detailed high confidence schedule for the Darlington Refurbishment Program which is reflected in the production forecast.

VECC Interrogatory #50

Issue Number: 11.5
Issue: Is OPG's proposed mid-term review appropriate?

Interrogatory

Reference:
Reference: A1/T3/S3/pg.12-

a) Is the sole purpose of the mid-term review to adjust for changes in the nuclear power production and fuel cost?

b) In OPG's view at what point might an adjustment to the production forecast call into question the reasonableness of the approved revenue requirement?

c) Why are fuel costs being included in the mid-term review? What is the materiality of potential change in fuel costs?

Response

a) Yes.

b) OPG does not believe that it is not possible to define, in the abstract, the point at which changes to the production forecast could call the reasonableness of the revenue requirement into question.

c) Please refer to Ex. L-11.5-1 Staff-259. As detailed in Chart 1 of F2-1-1, OPG's fuel cost per MWh is $5.74 and $5.13 for Pickering and Darlington respectively. The fuel cost associated with a one TWh production variance is therefore between $5.13M and $5.74M.

Board Staff Interrogatory #258

Issue Number: 11.5
Issue: Is OPG's proposed mid-term review appropriate?

Interrogatory

Reference:
Ref: Exh A1-3-3
OPG states that the scope of its mid-term review would be limited to the nuclear production forecast from July 1, 2019 through December 31, 2021, revisions to forecast fuel costs, and disposition of audited balances in deferral and variance accounts.

Does OPG propose to file for a mid-term review if the difference between the production forecast approved in the EB-2016-0152 proceeding is insignificantly different from the future OPG approved business plan? If not, what materiality test does OPG propose to use to determine whether or not the difference in the production forecast is significant enough to warrant a mid-term review?

Response

OPG proposes to file a mid-term review regardless of the predicted production forecast variance at that time. The OEB could then determine the nature of the proceeding warranted in the circumstances.

CCC Interrogatory #50

Issue Number: 11.5
Issue: Is OPG's proposed mid-term review appropriate?

Interrogatory

Reference:
Reference: Ex. A1/T3/S3/p. 10

Why is OPG limiting the mid-term review to an update of the production forecast and nuclear fuel costs? From OPG's perspective does the regulation preclude a consideration of other issues by the OEB through this mid-term review?

Response

Under O. Reg. 53/05, s. 6(2)(12)(ii), the OEB is required to determine nuclear revenue requirements on a five-year basis in this application. This requirement precludes re-examination of nuclear revenue requirement at the mid-term review. No such restriction exists for production forecasts, which are not part of revenue requirement. OPG has included Nuclear fuel costs in the mid-term review for the reasons outlined in Ex. L-11.5-20 VECC-50, part c).

Ontario

Ontario Energy Board Act, 1998
Loi de 1998 sur la Commission de l'énergie de l'Ontario

ONTARIO REGULATION 53/05

PAYMENTS UNDER SECTION 78.1 OF THE ACT

Consolidation Period: From March 2, 2017 to the e-Laws currency date.

Last amendment: O. Reg. 57/17.

This Regulation is made in English only.

Definition

0.1 (1) In this Regulation,

"approved reference plan" means a reference plan, as defined in the Ontario Nuclear Funds Agreement, that has been approved by Her Majesty the Queen in right of Ontario in accordance with that agreement;

"calculation period" means each period for which the Board determines the approved revenue requirements under subparagraph 12 ii of subsection 6 (2) together with the year immediately prior to that period;

"Darlington Refurbishment Project" means the work undertaken by Ontario Power Generation Inc. in respect of the refurbishment, in whole or in part, of some or all of the generating units of the Darlington Nuclear Generating Station;

"deferral period" means the period beginning on January 1, 2017, and ending when the Darlington Refurbishment Project ends;

"hydroelectric facilities" means the hydroelectric generation facilities prescribed in paragraphs 1, 2 and 6 of section 2;

"nuclear decommissioning liability" means the liability of Ontario Power Generation Inc. for decommissioning its nuclear generation facilities and the management of its nuclear waste and used fuel;

"nuclear facilities" means the nuclear generation facilities prescribed in paragraphs 3, 4 and 5 of section 2;

"Ontario Nuclear Funds Agreement" means the agreement entered into as of April 1, 1999 by Her Majesty the Queen in right of Ontario, Ontario Power Generation Inc. and certain subsidiaries of Ontario Power Generation Inc., including any amendments to the agreement.

"OPG weighted average payment amount" for a year means the total production-weighted average payment amount that is used in the determination of the payments made under section 78.1 of the Act with respect to the generation facilities prescribed in section 2 of this Regulation, calculated according to the formula:

$$(((NPA + NPR) \times NPF) + (HPA + HPR) \times HPF) / (NPF + HPF)$$

where,

NPA is the Board-approved payment amount for the year in respect of the nuclear facilities, NPR is the Board-approved payment amount rider for the year in respect of the recovery of balances recorded in the deferral accounts and variance accounts established for the nuclear facilities, excluding the deferral account established under subsection 5.5 (1),

NPF is the Board-approved production forecast for the nuclear facilities for the year,

HPA is the Board-approved payment amount for the year, or the expected payment amount resulting from a Board-approved rate-setting formula, as applicable, in respect of the hydroelectric facilities,

HPR is the Board-approved payment amount rider for the year in respect of the recovery of balances recorded in the deferral accounts and variance accounts established for the hydroelectric facilities, and

HPF is the Board-approved production forecast for the hydroelectric facilities for the year.

O. Reg. 23/07, s. 1; O. Reg. 353/15, s. 1; O. Reg. 57/17, s. 1.

(2) For the purposes of this Regulation, the output of a generation facility shall be measured at the facility's delivery points, as determined in accordance with the market rules. O. Reg. 312/13. s. 1.

Prescribed generator

1. Ontario Power Generation Inc. is prescribed as a generator for the purposes of section 78.1 of the Act. O. Reg. 53/05, s. 1.

Prescribed generation facilities

2. The following generation facilities of Ontario Power Generation Inc. are prescribed for the purposes of section 78.1 of the Act:

1. The following hydroelectric generating stations located in The Regional Municipality of Niagara:
   i. Sir Adam Beck I.

   ii. Sir Adam Beck II.

   iii. Sir Adam Beck Pump Generating Station.

   iv. De Cew Falls I.

   v. De Cew Falls II.
2. The R. H. Saunders hydroelectric generating station on the St. Lawrence River.
3. Pickering A Nuclear Generating Station.
4. Pickering B Nuclear Generating Station.
5. Darlington Nuclear Generating Station.
6. As of July 1, 2014, the generation facilities of Ontario Power Generation Inc. that are set out in the Schedule. O. Reg. 53/05, s. 2; O. Reg. 23/07, s. 2; O. Reg. 312/13, s. 2.

Prescribed date for s. 78.1 (2) of the Act

3. April 1, 2008 is prescribed for the purposes of subsection 78.1 (2) of the Act. O. Reg. 53/05, s. 3.

4. Revoked: O. Reg. 312/13, s. 3.

Deferral and variance accounts

5. (1) Ontario Power Generation Inc. shall establish a variance account in connection with section 78.1 of the Act that records capital and non-capital costs incurred and revenues earned or foregone on or after April 1, 2005 due to deviations from the forecasts as set out in the document titled "Forecast Information (as of Q3/2004) for Facilities Prescribed under Ontario Regulation 53/05" posted and available on the Ontario Energy Board website, that are associated with,

(a) differences in hydroelectric electricity production due to differences between forecast and actual water conditions;

(b) unforeseen changes to nuclear regulatory requirements or unforeseen technological changes which directly affect the nuclear generation facilities, excluding revenue requirement impacts described in subsections 5.1 (1) and 5.2 (1);

(c) changes to revenues for ancillary services from the generation facilities prescribed under section 2;

(d) acts of God, including severe weather events; and

(e) transmission outages and transmission restrictions that are not otherwise compensated for through congestion management settlement credits under the market rules. O. Reg. 23/07, s. 3.

(2) The calculation of revenues earned or foregone due to changes in electricity production associated with clauses (1) (a), (b), (d) and (e) shall be based on the following prices:

1. $33.00 per megawatt hour from hydroelectric generation facilities prescribed in paragraphs 1 and 2 of section 2.
2. $49.50 per megawatt hour from nuclear generation facilities prescribed in paragraphs 3, 4 and 5 of section 2. O. Reg. 23/07, s. 3.

(3) Ontario Power Generation Inc. shall record simple interest on the monthly opening balance of the account at an annual rate of 6 per cent applied to the monthly opening balance in the account, compounded annually. O. Reg. 23/07, s. 3.

(4) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records non-capital costs incurred on or after January 1, 2005 that are associated with the planned return to service of all units at the Pickering A Nuclear Generating Station, including those units which the board of directors of Ontario Power Generation Inc. has determined should be placed in safe storage. O. Reg. 23/07, s. 3.

(5) For the purposes of subsection (4), the non-capital costs include, but are not restricted to,

(a) construction costs, assessment costs, pre-engineering costs, project completion costs and demobilization costs; and

(b) interest costs, recorded as simple interest on the monthly opening balance of the account at an annual rate of 6 per cent applied to the monthly opening balance in the account, compounded annually. O. Reg. 23/07, s. 3.

5.1 REVOKED: O. Reg. 312/13, s. 3.

Nuclear liability deferral account

5.2 (1) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records, on and after the effective date of the Board's first order under 78.1 of the Act, the revenue requirement impact of changes in its total nuclear decommissioning liability between,

(a) the liability arising from the approved reference plan incorporated into the Board's most recent order under section 78.1 of the Act; and

(b) the liability arising from the current approved reference plan. O. Reg. 23/07, s. 3.

(2) Ontario Power Generation Inc. shall record interest on the balance of the account as the Board may direct. O. Reg. 23/07, s. 3.

5.3 REVOKED: O. Reg. 312/13, s. 3.

Nuclear development variance account

5.4 (1) Ontario Power Generation Inc. shall establish a variance account in connection with section 78.1 of the Act that records, on and after the effective date of the Board's first order under section 78.1 of the Act, differences between actual non-capital costs incurred and firm financial commitments made and the amount included in payments made under that section for planning and preparation for the development of proposed new nuclear generation facilities. O. Reg. 27/08, s. 1.

(2) Ontario Power Generation Inc. shall record interest on the balance of the account as the Board may direct. O. Reg. 27/08, s. 1.

Darlington refurbishment rate smoothing deferral account

5.5 (1) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records, on and after the commencement of the deferral period, the difference between,

(a) the revenue requirement amount approved by the Board that, but for subparagraph 12 i of subsection 6 (2) of this Regulation, would have been used in connection with determining the payments to be made under section 78.1 of the Act each year during the deferral period in respect of the nuclear facilities; and

(b) the portion of the revenue requirement amount referred to in clause (a) that is used in connection with determining the payments made under section 78.1 of the Act, after determining, under subparagraph 12 i of subsection 6 (2) of this Regulation, the amount of the revenue requirement to be deferred for that year in respect of the nuclear facilities. O. Reg. 353/15, s. 2.

(2) Ontario Power Generation Inc. shall record interest on the balance of the account at a long-term debt rate reflecting Ontario Power Generation Inc.'s cost of long-term borrowing that is determined or approved by the Board from time to time, compounded annually. O. Reg. 353/15, s. 2.

Rules governing determination of payment amounts by Board

6. (1) Subject to subsection (2), the Board may establish the form, methodology, assumptions and calculations used in making an order that determines payment amounts for the purpose of section 78.1 of the Act. O. Reg. 53/05, s. 6 (1).

(2) The following rules apply to the making of an order by the Board that determines payment amounts for the purpose of section 78.1 of the Act:

1. The Board shall ensure that Ontario Power Generation Inc. recovers the balance recorded in the variance account established under subsection 5 (1) over a period not to exceed three years, to the extent that the Board is satisfied that,

   i. the revenues recorded in the account were earned or foregone and the costs were prudently incurred, and

   ii. the revenues and costs are accurately recorded in the account.

2. In setting payment amounts for the assets prescribed under section 2, the Board shall not adopt any methodologies, assumptions or calculations that are based upon the contracting for all or any portion of the output of those assets.
3. The Board shall ensure that Ontario Power Generation Inc. recovers the balance recorded in the deferral account established under subsection 5 (4). The Board shall authorize recovery of the balance on a straight line basis over a period not to exceed 15 years.
4. The Board shall ensure that Ontario Power Generation Inc. recovers capital and non-capital costs and firm financial commitments incurred in respect of the Darlington Refurbishment Project or incurred to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2, including, but not limited to, assessment costs and pre-engineering costs and commitments,

   i. if the costs and financial commitments were within the project budgets approved for that purpose by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., or

   ii. if the costs and financial commitments were not approved by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., if the Board is satisfied that the costs were prudently incurred and that the financial commitments were prudently made.

4.1 The Board shall ensure that Ontario Power Generation Inc. recovers the costs incurred and firm financial commitments made in the course of planning and preparation for the development of proposed new nuclear generation facilities, to the extent the Board is satisfied that,

i. the costs were prudently incurred, and

ii. the financial commitments were prudently made.

5. In making its first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., the Board shall accept the amounts for the following matters as set out in Ontario Power Generation Inc.'s most recently audited financial statements that were approved by the board of directors of Ontario Power Generation Inc. before the effective date of that order:

i. Ontario Power Generation Inc.'s assets and liabilities, other than the variance account referred to in subsection 5 (1), which shall be determined in accordance with paragraph 1.

ii. Ontario Power Generation Inc.'s revenues earned with respect to any lease of the Bruce Nuclear Generating Stations.

iii. Ontario Power Generation Inc.'s costs with respect to the Bruce Nuclear Generating Stations.

6. Without limiting the generality of paragraph 5, that paragraph applies to values relating to,

i. capital cost allowances,

ii. the revenue requirement impact of accounting and tax policy decisions, and

iii. capital and non-capital costs and firm financial commitments to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2.

7. The Board shall ensure that the balance recorded in the deferral account established under subsection 5.2 (1) is recovered on a straight line basis over a period not to exceed three years, to the extent that the Board is satisfied that revenue requirement impacts are accurately recorded in the account, based on the following items, as reflected in the audited financial statements approved by the board of directors of Ontario Power Generation Inc.,

i. return on rate base,

ii. depreciation expense,

iii. income and capital taxes, and

iv. fuel expense.

7.1 The Board shall ensure the balance recorded in the variance account established under subsection 5.4 (1) is recovered on a straight line basis over a period not to exceed three years, to the extent the Board is satisfied that,

i. the costs were prudently incurred, and

ii. the financial commitments were prudently made.

8. The Board shall ensure that Ontario Power Generation Inc. recovers the revenue requirement impact of its nuclear decommissioning liability arising from the current approved reference plan.

9. The Board shall ensure that Ontario Power Generation Inc. recovers all the costs it incurs with respect to the Bruce Nuclear Generating Stations.

10. If Ontario Power Generation Inc.'s revenues earned with respect to any lease of the Bruce Nuclear Generating Stations exceed the costs Ontario Power Generation Inc. incurs with respect to those Stations, the excess shall be applied to reduce the amount of the payments required under subsection 78.1 (1) of the Act with respect to output from the nuclear generation facilities referred to in paragraphs 3, 4 and 5 of section 2.

11. In making its first order under section 78.1 of the Act in respect of Ontario Power Generation Inc. that is effective on or after July 1, 2014, the following rules apply:

    i. The order shall provide for the payment of amounts with respect to output that is generated at a generation facility referred to in paragraph 6 of section 2 during the period from July 1, 2014 to the day before the effective date of the order.

    ii. The Board shall accept the values for the assets and liabilities of the generation facilities referred to in paragraph 6 of section 2 as set out in Ontario Power Generation Inc.'s most recently audited financial statements that were approved by the board of directors before the making of that order. This includes values relating to the income tax effects of timing differences and the revenue requirement impact of accounting and tax policy decisions reflected in those financial statements.

12. For the purposes of section 78.1 of the Act, in setting payment amounts for the nuclear facilities during the deferral period,

    i. the Board shall determine the portion of the Board-approved revenue requirement for the nuclear facilities for each year that is to be recorded in the deferral account established under subsection 5.5 (1), with a view to making more stable the year-over-year changes in the OPG weighted average payment amount over each calculation period,

    ii. the Board shall determine the approved revenue requirements referred to in subsection 5.5 (1) and the amount of the approved revenue requirements to be deferred under subparagraph i on a five-year basis for the first 10 years of the deferral period and, thereafter, on such periodic basis as the Board determines,

    iii. for greater certainty, the Board's determination of Ontario Power Generation Inc.'s approved revenue requirement for the nuclear facilities shall not be restricted by the yearly changes in payment amounts in subparagraph i,

    iv. the Board shall ensure that Ontario Power Generation Inc. recovers the balance recorded in the deferral account established under subsection 5.5 (1), and the Board shall authorize recovery of the balance on a straight line basis over a period not to exceed 10 years commencing at the end of the deferral period, and

    v. the Board shall accept the need for the Darlington Refurbishment Project in light of the Plan of the Ministry of Energy known as the 2013 Long-Term Energy Plan and the related policy of the Minister endorsing the need for nuclear refurbishment. O. Reg. 23/07, s. 4; O. Reg. 27/08, s. 2; O. Reg. 312/13, s. 4; O. Reg. 353/15, s. 3; O. Reg. 57/17, s. 2.

7. Omitted (provides for coming into force of provisions of this Regulation). O. Reg. 53/05, s. 7.

SCHEDULE

1. Abitibi Canyon.
2. Alexander.
3. Aquasabon.
4. Arnprior.
5. Auburn.
6. Barrett Chute.
7. Big Chute.
8. Big Eddy.

9. Bingham Chute.
10. Calabogie.
11. Cameron Falls.
12. Caribou Falls.
13. Chats Falls.
14. Chenaux.
15. Coniston.
16. Crystal Falls.
17. Des Joachims.
18. Elliott Chute.
19. Eugenia Falls.
20. Frankford.
21. Hagues Reach.
22. Hanna Chute.
23. High Falls.
24. Indian Chute.
25. Kakabeka Falls.
26. Lakefield.
27. Lower Notch.
28. Manitou Falls.
29. Matabitchuan.
30. McVittie.
31. Merrickville.
32. Meyersberg.
33. Mountain Chute.
34. Nipissing.
35. Otter Rapid.
36. Otto Holden.
37. Pine Portage.
38. Ragged Rapids.
39. Ranney Falls.
40. Seymour.
41. Sidney.
42. Sills Island.
43. Silver Falls.
44. South Falls.
45. Stewartville.
46. Stinson.

47. Trethewey Falls.

48. Whitedog Falls.

O. Reg. 312/13, s. 5.