Ontario

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

DECISION AND ORDER

EB-2016-0152

ONTARIO POWER GENERATION INC.

Application for payment amounts for the period from January 1, 2017 to December 31, 2021

BEFORE: **Christine Long**
Vice Chair and Presiding Member

Cathy Spoel
Member

Ellen Fry
Member

December 28, 2017

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1 INTRODUCTION AND SUMMARY

This is a decision of the Ontario Energy Board (OEB) in response to an application filed by Ontario Power Generation Inc. (OPG) on May 27, 2016 seeking approval for changes in payment amounts for the output of its nuclear generating facilities and most of its hydroelectric generating facilities.

OPG is the largest electricity generator in Ontario. Provincial regulation requires that the OEB set the payment amounts that OPG charges for the generation from its nuclear facilities (Pickering and Darlington) and most of its hydroelectric facilities (including Sir Adam Beck I and II on the Niagara River, and RH Saunders on the St. Lawrence River). These payment amounts are included in the electricity costs which are shown as a line item on a customer's electricity bill sent from the customer's local electricity distributor.

The OPG application sought approval of $16,800 million of revenue requirement[1] over the period 2017 to 2021 for the nuclear facilities,[2] and approval of an inflation and productivity based formula for the determination of payment amounts for the hydroelectric facilities from 2017 to 2021.

In terms of the dollar amounts at issue, and the amount of supporting evidence, this was the largest rate case the OEB has ever heard. The OEB was assisted by the participation of 20 intervenors who represent a range of customer and other stakeholder interests, and OEB staff. The OEB was also assisted by 12 letters of comment received from customers.

OPG's application seeks approval for payment amounts to be effective January 1, 2017 and for each following year through to December 31, 2021. If the application and a smoothing proposal were approved as filed, OPG calculated that the typical residential customer's bill would increase by $0.65 a month in each year from 2017 to 2021.[3] The smoothing proposal would defer recovery of $1,005 million plus $116 million of interest to a future period.

Highlights of this Decision include:

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[1] The revenue requirement is the total cost for a utility to provide energy service. It includes the cost of salaries, equipment, capital projects, depreciation, taxes, interest and a return on the equity invested by shareholders. The revenue requirement is used to set rates for customers.
[2] The revenue requirement is adjusted by the productivity stretch proposed by OPG and reviewed in section 8.2 of this Decision.
[3] Application as amended on March 8, 2017, Exh N3-1-1. The bill impact calculation was performed before the Government of Ontario's Fair Hydro Plan (discussed below) was implemented.

- Reduction in OPG's proposed Operations, Maintenance and Administration budget for the nuclear business, mainly due to the results of poor OPG performance against its comparators, and excessive compensation when compared to its benchmarked comparators and its own performance, and other excessive costs. The reductions total $100 million per year
- Approval of OPG's application relating to the Darlington Refurbishment Program, including the addition of $4,800 million to rate base in 2020 when the first of the four units to be refurbished is expected to come back online
- Reduction of an estimated $33 million relating to the rate base additions of two nuclear operations capital projects based on an analysis of forecast and actual costs
- Approval of OPG's proposal to spend $292 million over the period 2017 to 2020 to pursue technical assessments related to extending operation of Pickering beyond 2020
- A requirement for higher productivity expectations underpinning the setting of nuclear payment amounts
- Approval of the hydroelectric payment amount setting formula, with one exception on the calculation of the inflation factor
- Rejection of OPG's proposal to change its debt/equity ratio from 55:45 to 51:49
- Approval of the nuclear production forecast as proposed
- Effective date for the new payment amounts will be June 1, 2017, rather than January 1, 2017 as proposed by OPG

The next step in the process will be for OPG to calculate the payment amounts in a manner that reflects these and other findings of the OEB, and to propose a way to smooth them out in accordance with the regulatory requirement to defer the collection of some of the revenue. Other parties will have an opportunity to make submissions, and the OEB will then make a finding on the final smoothed payment amounts. Only then will the exact payment amounts and customer bill impacts be known.

The impact of this Decision will not be seen on customer bills immediately due to smoothing and deferred revenue resulting from this proceeding. In addition, because of the Fair Hydro Plan, for residential customers and some other customers, the immediate impact will be lessened.

2 PAYMENT AMOUNTS DETERMINATION BY THE OEB

2.1 Legislative Requirements

Section 78.1 of the *Ontario Energy Board Act, 1998* (the Act), which is reproduced in Schedule A of this Decision, establishes the OEB's authority to set the payment amounts for the prescribed generation facilities. Section 78.1(4) states:

> The Board shall make an order under this section in accordance with the rules prescribed by the regulations and may include in the order conditions, classifications or practices, including rules respecting the calculation of the amount of the payment.

Section 78.1(5) states:

> The Board may fix such other payment amounts as it finds to be just and reasonable,
>
> (a) on an application for an order under this section, if the Board is not satisfied that the amount applied for is just and reasonable; or
> (b) at any other time, if the Board is not satisfied that the current payment amount is just and reasonable.

Ontario Regulation 53/05 (Payments Under Section 78.1 of the Act) (O. Reg. 53/05) provides that the OEB may establish the form, methodology, assumptions and calculations used in making an order that sets the payment amounts. O. Reg. 53/05 also includes detailed requirements that govern the determination of some components of the payment amounts. O. Reg. 53/05 can be found at Schedule B of this Decision.

O. Reg. 53/05 was amended on November 27, 2015 with new requirements related to "making more stable the year-over-year changes" in the nuclear payment amount during and following the $12.8 billion Darlington Refurbishment Program. The regulation was further amended on March 2, 2017, just before the hearing began, with the objective of smoothing the weighted average payment amounts (WAPA). The WAPA is comprised of hydroelectric and nuclear payment amounts and riders.

2.2 Memorandum of Agreement

OPG has entered into a Memorandum of Agreement with its shareholder, the Province of Ontario. This Memorandum sets out the shared expectations of OPG and its shareholder regarding OPG's governance, mandate, reporting, performance expectations and communications. Included in the provisions related to performance are expectations regarding efficiency and cost-effectiveness, and the expectation that OPG will undertake periodic benchmarking appropriate for its operations and type of assets, including as part of its submissions to the OEB. The Memorandum of Agreement is reproduced at Schedule C of this Decision.

2.3 The Regulated Generation Facilities

OPG owns and operates both regulated and unregulated generation facilities. As set out in section 2 of O. Reg. 53/05, the regulated, or prescribed, facilities consist of 54 regulated hydroelectric generating stations, 48 of which are organized in four plant groups, and two nuclear generating stations. The regulated facilities produce about half of the electricity consumed in Ontario.

Table 1: Regulated Generation Facilities

Hydroelectric				Nuclear	
Station	MW	Plant Group	MW	Station	MW
Sir Adam Beck I	427	Ottawa St. Lawrence	1,526	Pickering Units 1&4	1,030
Sir Adam Beck II	1,499	Central Hydro	108	Pickering Units 5-8	2,064
Sir Adam Beck PGS	174	Northeast	818	Darlington	3,512
DeCew Falls I	23	Northwest	658		
DeCew Falls II	144				
RH Saunders	1,045				
TOTAL	**3,312**		**3,110**		**6,606**

In 2010, the operations of Pickering Units 1 and 4 (formerly referred to as Pickering A) and Pickering Units 5 - 8 (formerly referred to as Pickering B) were amalgamated into a single station.

OPG also owns the Bruce A and B nuclear generating stations. These stations are leased on a long term basis to Bruce Power L.P. Under section 6(2)9 of O. Reg. 53/05, the OEB must ensure that OPG recovers all the costs it incurs with respect to the Bruce nuclear generating stations. Under section 6(2)10 of O. Reg. 53/05, the revenues from the lease, net of costs, are to be used to reduce the payment amounts for the prescribed nuclear generating stations.

2.4 Previous Payment Amounts Proceedings

This application is OPG's fourth cost forecast based application to set payment amounts. The previous proceedings are listed in the following table. The payment amounts currently in effect were set in the EB-2013-0321 proceeding.

Table 2: Previous Payment Amount Proceedings

File Number	Test Period
EB-2007-0905	2008-2009*
EB-2010-0008	2011-2012
EB-2013-0321	2014-2015

* Test period starting April 1

In addition to cost forecast based applications, OPG has filed applications to establish deferral and variance accounts or to clear the balances in deferral and variance accounts.[4] In the EB-2014-0370 proceeding, the OEB approved payment amount riders to recover the balances in certain deferral and variance accounts. The riders were effective until December 31, 2016.

[4] Variance accounts track the difference between the forecast cost of a project or program, which has been included in rates, and the actual cost. If the actual cost is lower, then the extra money is refunded to customers. If the actual amount is higher, then the utility can request permission to recover the extra amount through future rates. A deferral account tracks the cost of a project or program which the utility could not forecast when the rates were set. When the costs are known, the utility can then request permission to recover the costs in future rates.

3 THE APPLICATION AND PROCESS

3.1 The Application

This is the first incentive rate-setting (IR) application for OPG's nuclear and regulated hydroelectric generating facilities. In a letter dated February 17, 2015, the OEB stated that it expected OPG to develop an IR framework for the regulated hydroelectric facilities and a Custom IR framework for the nuclear facilities based on the principles outlined in the *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* (RRFE, now referred to as RRF). The OEB stated that a five-year application was expected.

OPG's application sought approval for hydroelectric payment amounts to be effective January 1, 2017 and approval of the formula used to set the hydroelectric payment amount for the period January 1, 2017 to December 31, 2021. The application sought approval for nuclear payment amounts to be effective January 1, 2017 and for each following year through to December 31, 2021.

On December 8, 2016, the OEB issued an order declaring the current hydroelectric and nuclear payment amounts interim as of January 1, 2017, pending the OEB's final determinations in this proceeding.

OPG applied for hydroelectric payment amounts that would be determined mechanistically by Price Cap Incentive Rate-setting (Price Cap IR) for the five-year period from 2017 to 2021.[5] OPG proposed a hydroelectric generation industry inflation factor, a hydroelectric generation industry productivity factor, and a stretch factor based on OPG's hydroelectric benchmark performance. OPG expects to file annual price-cap adjustment applications in the fall of each year to set the next year's hydroelectric payment amount. In this application, OPG seeks approval of the hydroelectric payment amount to be effective January 1, 2017, and a rider to clear the audited 2015 deferral and variance account balances over a two-year period. The proposed payment amount and rider are summarized below. The 2016 payment amount and rider are provided for reference.

[5] Price Cap IR is the standard formulaic method by which utility rates are annually adjusted during the incentive rate-setting period between cost of service applications. The formula adjusts current rates for the following year by inflation in input prices (costs of production or service) less expected productivity improvements including a stretch factor.

Table 3: Hydroelectric Payment Amounts and Riders

$/MWh	2016	2017
Hydroelectric Payment Amount	41.09	41.71
Hydroelectric Rider	3.83	1.44

OPG applied for 2017 to 2021 nuclear payment amounts under a Custom IR[6] framework that is based on the principles of the RRF and that is tied to OPG's total cost benchmarking performance for the nuclear business. The application is underpinned by OPG's 2016-2018 business plan and includes a smoothing proposal based on WAPA. In the period 2017 to 2021, $1,005 million would be deferred. The proposed revenue requirement for the nuclear business, as updated on March 8, 2017, is summarized in the following table.

[6] The Custom IR methodology sets rates for five years considering a five-year forecast of the utility's costs and sales volumes. This method is intended to be customized to fit the specific utility's circumstances, but expected productivity gains will be explicitly included in the rate adjustment mechanism. Utilities adopting this approach will need to demonstrate a high level of competence related to planning and operations.

Table 4: Proposed Nuclear Revenue Requirement

	$million	2017	2018	2019	2020	2021
	Expenses					
1	OM&A[1]	2,346.0	2,351.4	2,425.1	2,469.0	2,349.1
2	Nuclear Fuel	218.2	219.9	232.1	224.4	209.1
3	Depreciation	367.0	395.0	400.3	541.2	316.7
4	Property Tax	14.6	14.9	15.3	15.7	17.0
5	Income Tax	(6.7)	(18.4)	(18.4)	59.2	(5.0)
	Cost of Capital					
6	Short-term Debt	0.8	1.0	1.1	1.8	1.8
7	Long-term Debt	76.8	73.6	71.2	163.3	173.7
8	Return on Equity	133.5	136.0	133.7	308.1	328.6
9	Adjustment for lesser of UNL or ARC[2]	25.9	22.1	18.3	14.5	12.4
10	Other Revenue	31.7	22.0	22.7	22.2	22.9
11	Bruce Net Revenue	(16.9)	(17.1)	(27.4)	(23.8)	(38.1)
12	Revenue Requirement	3,161.3	3,190.6	3,283.4	3,798.8	3,418.4
13	Stretch Factor Reduction Amount		5.0	10.2	15.3	20.6
14	Deferred Revenue Requirement	251.0	162.0	(38.0)	488.0	142.0
16	Smoothed Revenue Requirement	2,910.3	3,028.6	3,321.4	3,310.8	3,276.4
16	Deferral and Variance Accounts	108.9	108.9			

Source: Exh N3-1-1 page 14 and Attachment 3

Note 1: Operations, Maintenance and Administration Costs

Note 2: UNL - unfunded nuclear liability, ARC - asset retirement cost

The proposed nuclear payment amounts, based on the smoothed revenue requirement, and the proposed rider to clear the audited 2015 deferral and variance account balances over a two-year period are summarized in the following table. The 2016 payment amount and rider are provided for reference.

Table 5: Nuclear Payment Amounts and Riders

$/MWh	2016	2017	2018	2019	2020	2021
Nuclear Payment Amount	59.29	76.39	78.6	84.83	88.21	92.02
Nuclear Rider	13.01	2.85	2.85			

A summary of the approvals that OPG is seeking in this application is found at Schedule D of this Decision.

3.2 The Process

The application as filed on May 27, 2016 was based on smoothing of the nuclear payment amounts. If approved, OPG stated that the application would result in an increase each year of $1.05 on the monthly total bill for a typical residential customer consuming 750 kWh per month.[7] A Notice of Application, issued on June 29, 2016, was published in 82 newspapers throughout the province.

Twenty parties applied for and were granted intervenor status. Twelve letters of comment were filed with the OEB in response to OPG's application. The letters expressed concern about the request to increase payment amounts and the difficulty that customers face in paying current electricity bills without any additional increase. Although the OEB will not address each letter specifically, the comments have been taken into account in the OEB's deliberations.

Over the course of the proceeding, the evidence was amended, supplemental evidence was filed, and three impact statements were filed. The last impact statement was related to the March 2, 2017 amendment to O. Reg. 53/05. As noted in the introduction, OPG's final proposal, based on smoothing of WAPA, would result in an increase each year of $0.65 on the monthly total bill for a typical residential customer, all else being equal. The increase relates to this application only. Customers' bills will also be impacted by other factors such as their distribution rates, transmission rates, and the overall bill reductions implemented through the Government of Ontario's Fair Hydro Plan.

The discovery phase for this proceeding included interrogatories and a technical conference. A settlement conference was held and settlement was achieved on some, mostly secondary, issues. The OEB approved the settlement proposal on March 20, 2017.[8] The settlement is attached as Schedule G to this Decision. The oral hearing took place over 23 days during the period from February 27, 2017 to April 13, 2017. The record closed on June 19, 2017 with the filing of OPG's reply argument.

During the proceeding, OPG sought confidential treatment for 173 documents. The OEB reviewed the documents and made determinations on the redacted text or the entire document as required.

Details of the procedural aspects of the proceeding are provided in Schedule E of this Decision.

[7] This is the impact identified by OPG in its original filing. OPG subsequently amended its application and revised the impact to $0.65 as noted earlier in this Decision. Both calculations were made before the Fair Hydro Plan was implemented.
[8] Tr Vol 9 page 1.

4 STRUCTURE OF THE DECISION

As part of its application, OPG filed a draft issues list. The OEB made provision for submissions on the list as well as prioritization of the issues as primary issues, which would proceed to oral hearing if unsettled, and secondary issues, which would proceed to written hearing if unsettled. The issues list was revised throughout the proceeding as discovery evolved. The issues list provided the structure for the interrogatories, settlement and oral hearing. The Final Issues List (Reprioritized) is attached as Schedule F of this Decision.

This Decision addresses the unsettled issues in the detail required to set payment amounts for 2017-2021. The Decision is organized into the following major sections: nuclear production forecast and revenue requirement, capitalization and cost of capital, deferral and variance accounts, methodologies for setting payment amounts, reporting, smoothing and implementation.

The submissions of OEB staff and the following parties are referred to in this Decision:[9]

- Association of Major Power Consumers in Ontario (AMPCO)
- Canadian Manufacturers & Exporters (CME)
- Consumers Council of Canada (CCC)
- Energy Probe Research Foundation (Energy Probe)
- Environmental Defence Canada Inc. (Environmental Defence)
- Green Energy Coalition (GEC)
- London Property Management Association (LPMA)
- Ontario Association of Physical Plant Administrators (OAPPA)
- Power Workers' Union (PWU)
- Quinte Manufacturers Association (QMA)
- School Energy Coalition (SEC)
- Society of Energy Professionals (Society)
- Sustainability-Journal
- Vulnerable Energy Consumers Coalition (VECC)

[9] A full list of all participants can be found in Schedule E. Although not all submissions are specifically referred to in this Decision, all were considered.

5 NUCLEAR FACILITIES

5.1 Nuclear Production Forecast

The historical production and test period production forecast are summarized in the following table. OPG seeks approval of a test period production forecast of 188.3 TWh. OPG also seeks approval of a mid-term review to update the nuclear production forecast for the final two-and-a-half years of the test period.

Table 6: Nuclear Production Forecast

TWh	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Darlington	28.9	26.0	26.5	29.0	28.3	25.1	28.0	23.3	25.7	19.0	19.3	19.7	17.7	16.6
Pickering	19.3	20.8	19.2	19.7	20.7	19.6	20.1	21.2	19.9	19.1	19.2	19.4	19.6	18.8
TOTAL	48.2	46.8	45.7	48.7	49.0	44.7	48.1	44.5	45.6	38.1	38.5	39.0	37.4	35.4

Source: Exh E2-1-1 Table 1 (EB-2010-0008, EB-2013-0321, EB-2016-0152), Undertaking J12.7

The production forecast methodology is based on maximum production less adjustments for planned outages, estimates of forced production loss as measured by the forced loss rate (FLR), and adjustments for other losses. In the EB-2013-0321 proceeding, OPG filed two impact statements that reduced the applied for production forecast. There was a change in OPG's approach to include increased scrutiny to be responsive to OPG senior management direction to address a gap in production forecasting. The EB-2013-0321 decision found that the 0.5 TWh adjustment per year for major unforeseen events was not required given the higher degree of scrutiny. The 2017 to 2021 production forecast in Table 6 above does not include adjustments for major unforeseen events, however the methodology used to develop the 2017 to 2021 production forecast maintains the approach set out in EB-2013-0321. OPG stated in reply argument that it "is confident that its methodology produces a robust forecast of the production anticipated during the IR term for both Pickering and Darlington."

OPG states that the test period forecast is particularly challenging given the Darlington Refurbishment Program (DRP) and the Pickering Extended Operations (PEO) project. Other challenges include the Pickering vacuum building outage in 2021, and the program to replace primary heat transport (PHT) pump motors at Darlington. The following table summarizes historical production in the period 2008 to 2015. OPG did not meet OEB-approved production forecast (variance at line 5 of the table), or its own production forecast (variance at line 4 of the table).

Table 7: Production Forecast Variance

	TWh	2008	2009	2010	2011	2012	2013	2014	2015	Average
1	Application	51.4	49.9		48.9	50.0		48.5	46.1	
2	OEB Approved	51.4	49.9		50.4	51.5		49.0	46.6	
3	Actual	48.2	46.8	45.8	48.6	49.0	44.7	48.1	44.5	
4	Variance (3-1)	-3.2	-3.1		-0.3	-1.0		-0.4	-1.6	-1.6
5	Variance (3-2)	-3.2	-3.1		-1.8	-2.5		-0.9	-2.1	-2.3

Source: Exh E2-1-1 Chart 2

OEB staff submitted that the test period production forecast for Pickering was overstated based on 2008 to 2016 actual production, and the results of initiatives undertaken to improve Pickering reliability and FLR. OEB staff also analyzed planned outage days net of days for PEO and determined that there was a 30% increase in the test period compared to the prior five-year period – which included outages related to Pickering Continued Operations. OEB staff submitted that a 1.5 TWh increase in the period 2017 to 2019 was appropriate, while LPMA argued for a 2.3 TWh increase for the same period. OPG argued that these submissions are contrary to the evidence when outages related to PEO are factored into the forecast. OPG stated that the planned outage analysis of OEB staff and LPMA is incorrect and did not include the material impact of forced extensions to planned outages.

Following the failure of a PHT pump motor at Darlington in 2015, OPG expedited a five-year program to replace the motors (four per unit) as failure results in a forced outage. The PHT pump motor replacements are scheduled in eight 20-day mini-outages in the period 2016-2021. While OEB staff questioned the efficiency of the PHT pump motor replacements, no reduction in Darlington production was proposed. OAPPA submitted that there were opportunities to schedule the PHT pump motor replacements concurrently with other planned outages. OAPPA's proposal would increase the production forecast by 2.95 TWh in the test period. OPG replied that it cannot shift the outages by several years as these large, complex motors are not readily available. While OPG would prefer to replace the motors in a planned outage, OPG states that the proposed schedule is based on safety and reliability considerations, as well as practical matters such as availability of new motors.

Findings

The OEB approves the proposed nuclear production forecast of 188.3 TWh for the test period. OPG states that its production forecast methodology is well developed and rigorous. The OEB observes that the variance between forecast and actual production forecast has improved starting in 2011 and has stayed lower than the 2008-2009 variance. However, the OEB does not approve the proposed mid-term review of production forecast. The OEB's mid-term review findings are set out in section 9 of this Decision.

While OEB staff and LPMA have proposed a higher production forecast for Pickering in the test period based on their analysis of historical and forecast Pickering production, the OEB approves OPG's proposal. The OEB accepts that the lower Pickering production forecast in the test period is largely related to the 7.5 TWh of production losses related to PEO,[10] and the planned 2021 vacuum building outage. The OEB notes that OPG's Pickering production forecast proposal is based on 5% FLR, which is challenging given the prior period FLR averaged 8.5%.[11]

The Pickering test period production forecast assumes that the PEO technical assessments will determine fitness for service beyond 2020, and that system planning and other regulatory considerations will be in place for operation in 2021. The OEB's findings on PEO are in section 5.7 of this Decision.

The OEB is not convinced that OAPPA's proposal, supported by LPMA, to replace Darlington PHT pump motors only during planned outages has fully considered all the risks. The consequences of pump motor failures are significant and result in an automatic reactor trip.[12] PHT pump motor failures resulted in production losses of 1 TWh in 2015 and 0.4 TWh in 2016.[13] The OEB approves OPG's proposal for Darlington production forecast and notes that the forecast is based on a 1% FLR for 2017 to 2019 versus 2.9% in the prior period. FLR will be higher as DRP progresses and refurbished units are returned to service beginning in 2020.

5.2 Nuclear Operations Capital and Rate Base

Background

The nuclear operations project portfolio includes OM&A projects and capital projects. The former are discussed in section 5.6 of this Decision. The historical and forecast nuclear operations capital expenditures, excluding DRP, are summarized in the following table:

[10] Reply Argument page 96.
[11] Exh E2-1-1 page 9.
[12] Reply Argument page 103.
[13] Tr Vol 13 pages 24-25.

Table 8: Nuclear Operations Capital Expenditures

$million	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Capital Project Portfolio	157.0	135.3	145.9	191.0	269.8	292.5	322.0	253.0	238.0	248.0	259.0	180.0
Pickering 2/3 Isolation	5.9											
Darlington New Fuel										15.3		
Minor Fixed Assets	15.4	12.9	15.5	10.2	22.9	22.3	31.0	26.0	20.0	19.1	19.5	19.3
Total	178.3	148.2	161.4	201.2	292.7	314.8	353.0	279.0	258.0	282.4	278.5	199.3
Five Year Average		2011-2015 Average: $223.7 million						2017-2021 Average: $259.4 million				

Source: Exh D2-1-2 Table 2, EB-2013-0321 and EB-2016-0152

The increase in capital expenditures starting in 2014 is largely related to DRP projects that were reclassified to the nuclear operations portfolio as these projects were determined to support the daily operations of the entire station. In total, $329 million of DRP projects were reclassified. The portfolio budget is administered by the Asset Investment Steering Committee (AISC). OPG states that the AISC review and Business Case Summary approval processes enhance OPG's ability to complete projects within budget and on schedule.

The historical and forecast nuclear operations in-service additions are summarized in the following table:[14]

Table 9: Nuclear Operations In-service Additions

$million	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Forecast	191.5	175.5	187.6	180.7	158.3	141.7	497.0	389.0	315.2	239.3	300.4	215.6
Actual	249.0	103.2	131.9	212.6	148.6	204.1	292.0					
Variance	57.5	-72.3	-55.7	31.9	-9.7	62.4	-205.0					
Updated - J21.1							292.0	479.0	354.7	385.4	244.7	181.6
Five Year Average		2011-2015 Actual Average: $160.1 million						2017-2021 (Updated) Average: $329.1 million				

Source: Exh D2-1-3 Table 4, EB-2013-0321 and EB-2016-0152, Undertaking J21.1

The historical and proposed nuclear rate base are summarized in the following table. The proposed rate base has been revised by the second impact statement, Exh N2-1-1, which excluded the in-service amount related to the DRP Heavy Water Storage and Drum Handling Facility Project (D2O project). DRP in-service additions are discussed in section 5.3. Asset retirement costs are discussed in section 5.13:

[14] There are support services capital projects entering rate base as well. For the test period, these additions range from $5 million to $18 million per year. The in-service additions with respect to DRP are discussed in section 5.3.

Table 10: Nuclear Rate Base

$million	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Net Plant (Excl DRP)	1,586.7	1,575.5	1,495.9	1,473.4	1,457.5	1,414.8	1,597.8	1,780.5	1,861.0	1,848.6	1,813.9	1,848.4
Net Plant (DRP)				60.2	121.2	192.6	419.1	611.9	601.5	586.7	4,699.1	5,154.5
Asset Retirement Cost	1,517.6	1,490.0	1,851.1	1,470.2	1,389.4	1,308.7	825.7	524.0	446.7	369.5	292.2	249.6
Total Nuclear Net Plant	3,104.3	3,065.5	3,347.0	3,003.8	2,968.1	2,916.1	2,842.6	2,916.4	2,909.2	2,804.8	6,805.2	7,252.5
Cash Working Capital	14.3	25.9	32.0	32.0	9.3	11.0	11.0	11.0	11.0	11.0	11.0	11.0
Fuel Inventory	335.0	345.4	340.7	330.6	316.1	301.4	280.3	251.9	242.2	224.2	210.7	208.6
Materials and Supplies	441.8	421.9	413.3	413.5	420.8	426.7	438.7	448.7	444.5	436.3	427.0	415.0
Total Rate Base	3,895.4	3,858.7	4,133.0	3,779.9	3,714.3	3,655.2	3,572.6	3,628.0	3,606.9	3,476.3	7,453.9	7,887.1

Source: Exh B1-1-1 Table 2, Exh B3-1-1 Table 1 (EB-2013-0321 and EB-2016-0152), J21.1

Submissions of the Parties

Some intervenors questioned the pattern of nuclear operations capital spending and the proposed significant capital program in the test period. AMPCO observed that 2017-2021 capital expenditures are 20% higher than the period 2010-2015, and further observed that in-service additions as a percentage of capital expenditures was increasing. In reply, OPG provided reasons for the increasing capital expenditures, including the reclassification of DRP projects. The pattern of in-service additions as a percentage of capital expenditures is not smooth and reflects the multiple year duration of nuclear projects.

OEB staff and several intervenors submitted that the test period in-service additions should be adjusted to reflect the actual 2016 capital additions and historical overstatement of in-service additions, which totaled $(190.9) million in the period 2010 to 2016. OEB staff submitted that the in-service amounts should be reduced by $27.3 million in each year of the test period. OPG argued that the submissions of most of the parties ignored the $70.3 million of 2016 in-service capital that was placed into service in early 2017. Considering the combined effect of in-service additions and depreciation, OPG argued that updating for 2016 actuals and using its updated forecast of 2017-2021 in-service additions[15] results in a $60 million increase in revenue requirement because the project mix includes more Pickering projects which have higher depreciation rates. In OPG's view, the parties' argument regarding the historical overstatement hinges on the large 2016 variance (i.e. a single data point).

The Projects and Modifications (P&M) organization is responsible for nuclear operations capital projects. The effectiveness of P&M was reviewed in interrogatories, cross-examination and submissions. SEC analyzed nuclear capital projects that have gone into service between 2014 and 2016 and argued that the projects are 11.7% above the cost set out in the first execution business case, and that for projects larger than $20

[15] Undertaking J21.1.

million, the variance is 41.8%. Analysis of actual completion vs. scheduled completion for projects larger than $5 million, indicated average delays of 17 months.

OEB staff and several intervenors submitted that P&M performance has been weak and that this performance has been documented in reports prepared by Burns and McDonnell and Modus Strategic Solutions (Modus) for the Nuclear Oversight Committee of OPG's Board of Directors. Several parties referred to the 2nd Quarter 2014 Report wherein Modus cited P&M management failure for campus plan projects (projects related to DRP that also support ongoing operation of Darlington). The 2nd Quarter 2014 Report noted that P&M management failures were most evident with respect to the D2O Project[16] and the Auxiliary Heating System (AHS) project. AMPCO argued that OPG should undertake an audit of its P&M project controls in time for the mid-term review and provide a status report at that time.

The parties submitted that there should be rate base disallowances based on poorly developed estimates, flawed contractor selection and weak day to day risk management. The parties proposed reductions to in-service amounts ranging from $14.4 million to $53.1 million for the AHS project and reductions ranging from $7 million to $14.9 million for the Operations Support Building project. OPG argued that its application should stand, noting that increases are related to flawed initial estimates and that the final costs are the true costs of these projects.

Findings

Capital and Rate Base

This application is a five-year Custom IR. Accordingly, the opening rate base for 2017 should be based on the best information available. Undertaking J14.1 confirms that the 2016 nuclear operations in-service additions were significantly lower, i.e. $205 million lower, than planned. Undertaking J14.1 also notes that $70.3 million of the nuclear operations in-service additions originally planned for 2016 had been placed in-service by the first quarter of 2017. OPG has provided a revision to in-service amounts and rate base in Undertaking J21.1. That revision reflects the update for actual 2016 in-service amounts and changes in timing of in-service amounts in the test period underpinned by the 2017-2019 Business Plan. Some of the intervenors have submitted that the 2016 in-service additions should be revised, but that the test period in-service additions should

[16] In Exh N2-1-1 filed on February 22, 2017, OPG updated its application to remove the in-service amounts related to the D2O project due to project uncertainty. The revenue requirement impact will be recorded in the Capacity Refurbishment Variance Account once the project is in service.

remain as originally filed. The OEB finds that the Undertaking J21.1 forecast represents the appropriate starting point for the OEB's consideration. The forecast is updated to reflect OPG's best available information for the entire period from 2016 to 2021. The proposal of the intervenors to update only 2016 would not account for the cascading effects of additions in the test period. The OEB's finding on this matter applies to nuclear operations capital and support services capital.

The scope of capital expenditure on nuclear operations has expanded to include reclassified projects from DRP, replacement of obsolete equipment and additional Canadian Nuclear Safety Commission regulatory requirements, for example, related to Fukushima. As shown in Table 8, capital expenditures have increased in the bridge and test period. SEC submitted that the planned level of nuclear operations capital spending is much higher than historical levels. However OPG argued that the average 2017-2021 capital expenditures ($259.4 million) are in line with the historical period average 2013-2015 capital expenditures ($269.6 million).[17] The OEB observes, however, that a review of a five-year historical period average from 2011-2015 ($223.7 million) supports the SEC submission.

Based on the variance between 2010 to 2016 forecast and actual in-service additions, OEB staff submitted that in-service additions should be reduced by $27.3 million for each year of the test period (the total seven-year variance offset by the 2017 additions previously forecast for 2016). SEC submitted that a 12.5% reduction (the total seven-year variance as a percentage of the total additions) was appropriate. AMPCO argued that in-service additions should be reduced by 15% annually based on the in-service variance and AMPCO's review of variances for projects of different sizes and schedule delays. AMPCO suggested that a lumpy pattern of in-service capital additions and positive and negative variances would not be unexpected. The OEB concurs with OPG that the 2010-2016 seven-year variance of $(190.9) million is largely driven by the 2016 variance of $(205.0) million.

The forecast and actual in-service additions for 2016 are significantly higher than the period 2010 to 2015 and the forecast for the test period, both as filed and as revised, is higher than historical. The five-year 2010-2015 average actual in-service additions is $160.1 million while the five-year 2017-2021 average revised in-service additions is $329.1 million. OPG was not able to achieve the forecast 2016 nuclear operations in-service additions, and it is uncertain whether OPG will have the resources to execute a nuclear operations capital program with higher capital expenditures and a much higher level of in-service additions. The elevated capital expenditures and in-service additions

[17] Reply Argument page 33.

are concurrent with DRP which could further divert resources from the ambitious nuclear operations capital program, also contributing to delayed in-service additions.

The OEB finds that some reduction to the in-service capital additions is required. The OEB finds that the reductions proposed by SEC and AMPCO are too aggressive. Instead, the OEB finds that a 10% reduction each year (2017-2021) to the non-DRP nuclear operations and support services in-service capital additions is appropriate (using the updated forecast from Undertaking J21.1 as the starting point). The OEB notes that a similar reduction was ordered by the OEB in the last OEB decision on payment amounts with respect to OPG's hydroelectric in-service additions.[18]

The OEB's findings on nuclear Custom IR and productivity are in section 8.2. In accordance with those findings, the OEB orders OPG to apply a 0.6% stretch factor to the revenue requirement associated with the nuclear operations and support services in-service capital additions in each year from 2017 to 2021. The revenue requirement reductions related to the application of the stretch factor shall be applied in the typical manner whereby the reductions in each year persist going forward (during the entire 2017-2021 period). The OEB finds that the application of a stretch factor to the nuclear operations and support services in-service capital additions is appropriate. The OEB expects that OPG will achieve productivity improvements with respect to the delivery of its nuclear operations capital program during the 2017-2021 term and those productivity savings should be passed on to ratepayers.

Projects & Modifications Performance

The effectiveness of the P&M organization has been criticized by some intervenors. The evidence relied on by the intervenors included the 2nd Quarter 2014 Report to the Nuclear Oversight Committee of OPG's Board of Directors, prepared by Burns and McDonnell and Modus Strategic Solutions (Modus report), as well as OPG internal audit reports. SEC has completed an analysis of cost and schedule for historical projects and submitted that, "The Board can expect projects to continue to be over-budget and behind schedule. This means OPG will either overspend compared to its budget or, more likely, do fewer projects. Neither scenario is good for ratepayers."[19] OPG replied that the Operations Support Building project and the AHS project are the main contributors to the variances, and that OPG is close to budget otherwise. OPG stated that factors such as limited outage windows affect project scheduling.

[18] EB-2013-0321, Decision with Reasons, page 21.
[19] SEC Submission page 58.

AMPCO reviewed iterations of business case summaries and submitted that the number of superseding business cases indicated poor P&M performance. AMPCO also submitted that P&M has delayed implementing lessons learned and that project management practices such as the gated process were mentioned in the previous cost of service proceeding. Energy Probe questioned why it has taken OPG so long to overhaul its procedures for the P&M group. OPG maintains that it has been responsive to the Modus report and that subsequent reports have acknowledged OPG efforts to improve P&M.

As in all cases, it is the utility's responsibility to file an application that supports its proposals. It is not clear to the OEB that P&M project management processes and outcomes exhibit continuous improvement. There is a large volume of evidence – filed with the application, with interrogatory responses and in undertakings. There was extensive examination regarding estimates, classes of estimates, process controls, independent reviews and internal audits. OEB staff and the intervenors have argued that there are some P&M deficiencies. OPG argues that that the intervenors do not fully understand the reasons for schedule delays or the business case summary process,[20] and did not refer to the positive findings of internal OPG audit reports subsequent to the Modus report. The OEB finds that there is room for improvement in P&M performance and the findings on stretch factor implement this finding. The OEB also finds that disallowances related to two projects, the Operations Support Building (OSB) and the AHS, are appropriate, as discussed below.

AMPCO submitted that OPG should undertake an audit of its P&M project controls and file a status report at the mid-term review. OPG argued that this amounts to micromanaging. The OEB is not convinced that project controls are as robust as they could be. Robust project controls are a critical component of good planning and execution of capital projects that allow projects to be completed on time and on budget. Therefore, the OEB directs OPG to file an independent audit of its nuclear P&M organization including adherence to best practices, measures and reporting regarding cost and schedule performance, and implementation of lessons learned. The audit report will be filed with OPG's next cost-based application.

Auxiliary Heating System and Operations Support Building

OEB staff, AMPCO, CME, Energy Probe, LPMA, SEC and VECC have all proposed disallowances with respect to AHS and OSB rate base additions. These projects were classified as DRP projects in the previous EB-2013-0321 proceeding, but have since been reclassified. However, P&M managed the AHS and OSB projects when they were

[20] Reply Argument page 38.

considered DRP projects. The parties have suggested a range of disallowances referring to the range of estimates and forecasts filed in this proceeding[21] and the Modus report. The AHS project was specifically reviewed in the Modus report.

OPG submitted that the majority of the variances relate to initial estimation concerns and scope additions, and that the OEB should accept the OPG proposal as filed. Had the work been properly estimated and the full scope of work been known initially, OPG submitted that the original cost would be close to the current cost.

The estimates and forecasts for the AHS are:

- EB-2013-0321 as filed – $36.3 million (last EB-2013-0321 update $75.3 million)
- First execution business case – $45.6 million
- Forecast/proposed final cost – $107.1 million ($98.7 million in-service amount)

Clearly the original forecast has grown substantially from what was filed in the EB-2013-0321 proceeding.

The OEB does not accept OPG's position. The current cost is not the same as the prudently incurred cost. It is not obvious whether the best alternative was selected or whether costs for the alternative selected were contained. The Modus report states that, "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."[22] CME submitted that the evidence demonstrates that OPG's management of the AHS fell short of what ratepayers should expect: "OPG's argument that ratepayers are receiving value for the scope of work which was ultimately involved in completing the AHS project fails to take into account the lost opportunity to pursue alternative and less costly options for achieving the same outcome."[23] In response to cross-examination by SEC, OPG agreed that poor baseline information can lead to cost increases and schedule delays.

The parties have proposed disallowances that range from 100% of the variance between the first execution business case and the proposed in-service addition to 50% of the variance. The OEB has considered the submissions of the parties as well as the

[21] JT2.16.
[22] Exh L-4.3-Staff-72 Attachment 4.
[23] CME Submission page 25.

Supplemental Report prepared by Modus.[24] That report comments on the D2O and AHS projects, and states that the causes of cost overruns "root from mistakes made by management." The report also states that "many of the cost variances appear to be scope based, i.e. OPG is getting more value albeit for a higher cost." On the basis of these two considerations, mismanagement and increased scope, the OEB disallows 50% of the variance between the first execution business case and the proposed in-service addition on a permanent basis. The OEB estimates the reduction resulting from its finding to equal about $27 million. However, in the draft payment order, OPG should provide the detailed calculation showing the OEB ordered reduction related to the AHS based on 50% of the variance between the in-service amount set out in the first execution business case and the current proposed in-service amount.

The OEB is prepared to accept that there may be some merit to OPG's argument that there was an increase in scope. However, the OEB is not prepared to accept that the entire increase in cost is due to an increase in scope. The evidence shows that there were other options available to OPG when selecting a contractor that may not have been adequately explored. In addition, the Modus report speaks to issues with management of the project. The OEB cannot determine on an exact basis how much of the increased cost is due to additional scope and how much is due to project management issues. Therefore the OEB has considered both factors and has determined it will allow 50% of the increased cost on account of increased scope and disallow 50% of the increased cost to account for poor management.

The estimates and forecasts for the OSB are:

- EB-2013-0321 as filed – $29.7 million (last EB-2013-0321 update $45.1 million)
- First execution business case – $47.8 million
- Forecast/proposed final cost – $62.7 million ($60.6 million in-service amount)

Clearly the original forecast has grown substantially from what was filed in the EB-2013-0321 proceeding.

The submissions of OEB staff and the intervenors on the OSB are similar to their submissions on the AHS. The OEB finds that final costs for a building refurbishment that are double those initially filed in EB-2013-0321 are not reasonable. A senior OPG executive made a notation that "This is poor performance" on the Project Over-Variance Approval form seeking an increase from $53 million to $62 million for the

[24] Undertaking J15.3 Attachment 1 page 3.

OSB.[25] The notation on the Variance Approval form does not speak to the entire increase in cost of the OSB, but it does indicate that there was a performance issue on this project as well. Because the OEB cannot determine the exact amount of increased cost due to performance issues, the OEB has exercised its judgment and disallows 50% of the variance between the first execution business case and the proposed in-service addition on a permanent basis. The OEB calculates the reduction resulting from its finding to equal about $6 million. However, in the draft payment order, OPG should provide a detailed calculation showing the OEB-ordered reduction related to the OSB based on 50% of the variance between the in-service amount set out in the first execution business case and the current proposed in-service amount.

The methodology proposed by OPG to calculate rate base is accepted. However, the OEB's findings with respect to nuclear operations capital will impact the rate base amount. The OEB's findings for establishing the nuclear operations and support services rate base and capital additions shall be implemented as follows. The starting point for the rate base amounts and in-service capital additions for the 2017-2021 period is the updated forecast provided by OPG in Undertaking J21.1. The permanent disallowances associated with the AHS and OSB should first be removed from the amounts set out in the updated forecast. The 10% reduction should then be applied to the in-service capital additions net of the permanent disallowances. Finally, the stretch factor should be applied to the revenue requirement associated with the reduced nuclear operations and support services in-service capital additions resulting from the OEB-ordered disallowances.

For future proceedings, the OEB directs OPG to file, at a minimum, the costs for each major capital project based on the first execution business case and the final proposed amount for which OPG is seeking approval. The information provided should be sufficiently detailed as to adequately highlight both the total cost and the related in-service amount.

Operation of CRVA and Nuclear Operations Capital Projects

The Capacity Refurbishment Variance Account (CRVA) was established pursuant to section 6(2)4 of O. Reg. 53/05 to record the variance between certain actual capital and non-capital costs incurred and those costs underpinning payment amounts. The costs eligible for the CRVA are related to projects that increase the output of, refurbish or add operating capacity to a regulated generating facility.

[25] Exh D2-1-3 Attachment 1 Tab 1.

OEB staff raised a double counting concern in its submission.[26] If OPG placed less nuclear operations capital in service than approved, and if OPG places more CRVA eligible capital in service than approved, OPG would notionally recover the revenue requirement twice. OEB staff proposed that any nuclear operations in-service addition “credits” offset any CRVA “debits”. CCC explored this matter in cross-examination.[27] CCC compared OPG’s hydroelectric proposal with respect to the operation of the CRVA with OPG’s proposed status quo operation for the nuclear sub-account of the CRVA. While the nuclear revenue requirement is based on annual capital plans for five years instead of mechanistic updates, CCC submitted that the remedy proposed by OEB staff should be implemented.

OPG has proposed that the operation of the nuclear sub-account of the CRVA continue as it has operated since the account was established. OPG argued that OEB staff and CCC’s comparisons are wrong as different regulatory frameworks have been applied for the hydroelectric and nuclear businesses.[28] The OEB does not agree with OEB staff’s and CCC’s proposal. The potential outcome of the proposal is that prudently incurred CRVA eligible costs will be disallowed for recovery. OPG is entitled to recover prudently incurred CRVA-eligible costs as per the regulation. The OEB finds that the operation of the nuclear sub-account of the CRVA will continue as proposed by OPG.

Nuclear Projects Subject to CRVA

Under issue 4.1, OPG requested that section 6(2)4 of O. Reg. 53/05, and the associated CRVA treatment, apply to: (a) the capital and non-capital costs of the DRP; (b) the capital and non-capital costs of the Darlington Spacer Retrieval Tooling project; (c) the non-capital costs for the PEO project (including the Fuel Channel Life Assurance project); (d) the non-capital Fuel Channel Life Extension project (including ongoing costs); and (e) the Fuel Channel Life Management project.[29]

OEB staff submitted that the DRP and the other nuclear projects discussed above, as set out at OPG’s updated response to an OEB staff interrogatory, meet the requirements of section 6(2)4 of O. Reg. 53/05 and therefore CRVA treatment applies.

The OEB finds that the projects for which OPG requested section 6(2)4 of O. Reg. 53/05 apply are appropriate. The OEB notes that no parties disagreed with OPG’s request.

[26] OEB staff submission page 62.
[27] Tr Vol 20 page 82.
[28] Reply Argument page 207.
[29] Exh L-4.1-Staff-24 pages 1-2.

Capitalization of Darlington Unit 2 New Fuel

OPG proposes to capitalize half of the cost of new fuel for Darlington Unit 2 in 2019 when the fuel is loaded into the reactor, to be depreciated after the unit is in service over the life of the station. AMPCO submitted that it is not OPG's past practice to capitalize new fuel and that OPG's evidence to support the capitalization is weak. OPG replied that AMPCO mischaracterized the interrogatory response regarding new fuel.[30] There is no past OPG practice as Darlington Unit 2 is the first instance of a full new fuel load since OPG's inception. However, the practice is consistent with USGAAP and was applied by the former Ontario Hydro. The OEB accepts the new fuel capitalization proposal as it is consistent with accounting guidance and past practice.

Projects for Future Review

Undertaking J7.3 is an internal OPG audit, "Project Controls Audit – Project & Modifications Group," March 9, 2016. The report reviewed 13 projects and identified deficiencies related to cost and schedule baseline information. OEB staff observed that the Darlington Class II Uninterruptable Power Supply Replacement and the Fukushima Phase 1 Beyond Design Day Event Project are not near completion. OEB staff submitted that the in-service amounts may include costs that were imprudently incurred and that the OEB should identify these two projects as requiring further review at the cost rebasing when these projects are complete. OPG argued that this advance identification is unwarranted and unnecessary as the OEB has the ability to assess any cost variances at rebasing. The OEB finds that processes in place are sufficient and that advance identification is not necessary.

Draft Payment Amounts Order

The OEB requires OPG to incorporate the OEB's findings on nuclear operations and support services rate base and in-service additions in the determination of revenue requirement. The filing will be consistent with the LPMA submission with respect to the filing of fixed asset continuity schedules and changes in depreciation, to which OPG agreed. OPG shall file detailed fixed asset continuity schedules for each year that reflect the changes ordered by the OEB as well as the details of changes in the depreciation expense as part of the draft payment amounts order.

[30] Exh L-6.3-Staff-111.

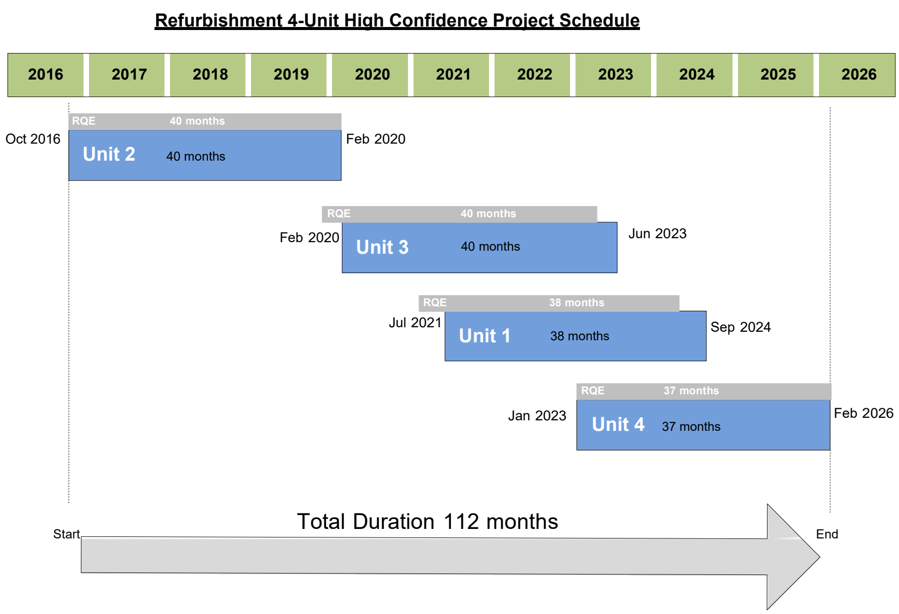
5.3 Darlington Refurbishment Program

5.3.1 DRP Planning and Costs

Background

The Darlington Refurbishment Program (DRP) is a $12.8 billion "megaprogram" to refurbish all four units at the Darlington nuclear station with a view to extending the life of the station until approximately 2055. OPG calls it a "destiny project" on which the company's future, and indeed the future of the Canadian nuclear industry, depend.

The first unit to be refurbished, Unit 2, was disconnected from the power grid (breaker open) in October 2016, and is forecast to come back online in February 2020. As the schedule below shows, the last of the units is expected to be completed in 2026.[31]



After ten years of planning, OPG's board of directors approved a Release Quality Estimate (RQE), setting out the detailed budget and schedule for the entire four-unit program, in November 2015. The RQE breaks down the $12.8 billion total cost as follows:

[31] Exh L-4.3-Staff-55 Attachment 1.

Table 11: Release Quality Estimate

Program Component	RQE Total Cost (Billion $)	RQE Total Cost (%)
Major Work Bundles	5.54	43
Safety Improvement Opportunities	0.20	2
Facilities & Infrastructure Projects	0.64	5
OPG Functional Support	2.23	17
Early Release Funds	0.11	1
Contingency	1.71	13
Interest & Escalation	2.37	19
Total Cost Estimate	**12.8**	**100**

The RQE is said to represent a "P90" confidence level. As OPG explains in its Argument in Chief, "A P90 estimate means there is a 90% chance that the actual project cost will not exceed the estimated amount." This confidence level was determined through statistical modeling of risks identified by OPG.

By the time of the hearing, about $2.9 billion of the $12.8 billion had already been spent.

In this application, OPG is seeking approval for rate base additions of $4.8 billion of in-service amounts associated with the Unit 2 refurbishment (including contingency, interest and escalation), along with $377 million in in-service amounts for other DRP-related facilities that will enter into service during the test period. No costs for the refurbishment of the other three units are requested in this proceeding, as they will not complete their refurbishments during the test period.

For the reasons that follow, the OEB approves the additions to rate base as proposed by OPG.

Regulatory Framework

The OEB's jurisdiction in respect of the DRP is limited by O. Reg. 53/05. The regulation states in paragraph 6(2)12 that "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." The question of whether the DRP makes economic sense or is otherwise justified as a matter of electricity system planning was therefore out of scope in this proceeding.

The 2013 Long-Term Energy Plan, to which the regulation refers, states that "The government is committed to nuclear power," and that "Refurbished nuclear is the most cost-effective generation available to Ontario for meeting base load requirements." The Government of Ontario reiterated its support for the DRP in January 2016, after the RQE was finalized.

The regulation also stipulates in paragraph 6(2)4 that the OEB must allow OPG to recover DRP-related costs so long as they are prudent: "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 … including, but not limited to, assessment costs and pre-engineering costs and commitments… if the Board is satisfied that the costs were prudently incurred and that the financial commitments were prudently made."

This requirement is reflected in OPG's Capacity Refurbishment Variance Account (CRVA), which the OEB has approved in every payments amount case since it was given jurisdiction over payment amounts.[32] Under the CRVA, if OPG were to go over budget on the DRP, a balance would build up in the CRVA, and the OEB would review the prudence of the overruns before approving the disposition of the balance. The CRVA is symmetrical: if the program went under budget, the excess amounts collected through payment amounts would be returned to ratepayers in a future proceeding.

Matters related to the safety, security and environmental impacts of the Darlington station and the DRP are regulated by the Canadian Nuclear Safety Commission (CNSC). The CNSC reviewed OPG's environmental assessment of the DRP and determined in March 2013 that the program would not result in significant adverse environmental effects given the proposed mitigation measures. In December 2015, the CNSC renewed the operating licence for Darlington until November 30, 2025 and found that OPG is qualified to undertake the DRP.

Planning, Contracting and Oversight

Much of the evidence in this proceeding related to the extensive planning efforts that OPG has undertaken to prepare for the execution of the DRP. OPG explained that there are three phases to the DRP: Initiation, Definition and Execution. The exploratory Initiation Phase began in 2007 and was completed at the end of 2009 when OPG's board of directors agreed to proceed with the DRP. The Definition Phase culminated in the RQE, which was approved by the board of directors in November 2015, and endorsed by the Minister of Energy shortly thereafter. OPG explained that the Definition Phase included an extensive effort to define the scope of the program. The RQE incorporates a high-confidence (P90) budget and schedule.[33]

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[32] In the first payment amounts decision, EB-2007-0905 (November 3, 2008), the OEB wrote: "In light of the obligation imposed on the Board by Section 6(2)4, the Board accepts that a variance account is required for the period beginning April 1, 2008 and authorizes OPG to establish the capacity refurbishment variance account."
[33] Tr Vol 1 page 32.

During the Definition Phase, OPG also sought to identify and incorporate “lessons learned” from other nuclear projects and other megaprojects. This included a thorough review of why prior refurbishments of CANDU nuclear power plants have experienced challenges, namely the refurbishments at Bruce Power, Point Lepreau (New Brunswick) and Wolsong (South Korea). OPG also built a full-scale reactor mock-up in order to test tools and train staff – something that had not been done for the earlier CANDU refurbishments. OPG awarded the major DRP contracts, and worked with the contractors to complete the detailed engineering for the program. In total, OPG spent $2.2 billion during the Definition Phase.

OPG is using a “multi-prime contractor model” where there is more than one prime contractor and OPG has a separate contract with each of them. As the owner and integrator between contractors, OPG has overall project management responsibility and design authority, with the assistance of external technical and project management experts. The benefits of this model are said to be that OPG retains control over the project, including deliverables, costs and schedules. OPG’s functional support costs for DRP are forecast to be $2.2 billion.

OPG explained that it used different contracting strategies for each of the five major work bundles (retube and feeder replacement [RFR], turbine generator, steam generator, defueling and fuel handling, and balance of plant), which it says balanced the need and ability of OPG to transfer risk to its contractors against the benefit of achieving a lower price. By far the largest contract by value is the $3.4 billion contract for the RFR. The RFR contract is based on the Engineering, Procurement and Construction model and combines fixed pricing for known or highly definable tasks with target pricing for work that is less definable. If the actual cost of the work ends up being more or less than the estimate, the difference (outside a neutral band) would be shared by OPG and the contractor, through a system of incentives and penalties. The major DRP contracts were filed with OPG’s application (with some redactions approved by the OEB for the versions placed on the public record).

OPG provided an assessment of its contracting strategies prepared by Concentric Energy Advisors (which was initially filed in the EB-2013-0321 case). Concentric concluded that the commercial strategies employed by OPG were appropriate and met the regulatory standard of prudence. In July 2016 Concentric provided an update report on the RFR contract and stated that the terms of the finalized contract, including the target price and the allocation of risk, are prudent.

OPG also filed an expert report by Dr. Patricia Galloway of Pegasus Global Holdings Inc., an expert in megaprojects, on the degree to which OPG’s plan and approach to the execution of the DRP was consistent with the way other projects of comparable size and complexity have been carried out. Dr. Galloway states in her report that, "Based on the review of OPG's governance, policies and procedures, and project controls developed and in use for the Program, and interviews conducted with OPG personnel, I found that OPG has reasonably and prudently prepared for its execution of the DRP."[34] Other key findings by Dr. Galloway include:

- "OPG sought to find the most qualified individuals in the industry to manage the Program and the individuals that were assigned to manage the Program are qualified and competent"[35]
- "OPG's oversight process is thorough, complete and consistent with what I would expect from a reasonable and prudent utility company embarking on this type of megaprogram"[36]
- "In reviewing OPG's policies and procedures, both from an organizational and program-specific standpoint, I found they are exemplary in their thoroughness and alignment with other individual policies and procedures providing OPG with a comprehensive tool from which it can properly execute the Program"[37]
- "I found the methodologies employed by OPG to develop the RQE estimate to be *world-class*"[38]

OEB staff also engaged an independent expert in megaproject planning and risk management: Kenneth M. Roberts, the chair of the construction law group at the US law firm, Schiff Hardin, LLP. Mr. Roberts agreed with Dr. Galloway that OPG's planning was thorough and in accordance with industry standards. Asked to summarize his conclusions at the oral hearing, Mr. Roberts answered:

> Specifically, my opinions included the following: That the DRP risk and OPG risk assessment are in fact consistent with industry standard practices used by utilities and large capital construction projects of similar size and complexity; that OPG's planned project control system for the DRP to manage costs and schedule are consistent with industry standard practices used by utilities in large capital construction projects of similar size and complexity; that OPG's program and project management staffing plans and the written management policies and procedures for the DRP are consistent with industry standards used by utilities in large capital projects; that OPG's contracting strategy, contract terms, and contractual risk allocation between OPG and the contractors for the DRP are consistent with industry standards for [risk] shifting on projects of this size and complexity.[39]

[34] Exh D2-2-11 Attachment 2, page 8.
[35] Exh D2-2-11 Attachment 2, page 40.
[36] Exh D2-2-11 Attachment 2, page 40.
[37] Exh D2-2-11 Attachment 2, page 43.
[38] Exh D2-2-11 Attachment 2, page 51 [emphasis in original].
[39] Tr Vol 7 pages 13-14. The transcript erroneously refers to "rate shifting" in the last sentence.

He cautioned, however, that no amount of planning can ensure the smooth execution of a megaproject: "All megaprojects experience some form of cost and/or schedule issues, which may include but [are] not limited to commercial challenges, changes, unexpected and high-impact events and/or delays. It's not a question of whether these types of events will occur. It's a matter of how OPG handles and responds to these issues when they arise."[40]

The DRP is now in the third and final phase: the Execution Phase. There are multiple layers of oversight, including but not limited to: a special DRP committee of the board of directors, which has engaged its own external expert; OPG's internal audit group; and the Refurbishment Construction Review Board, which is made up of external individuals with expertise in megaprojects and nuclear power and which reports to OPG's CEO and the Chief Nuclear Officer. OPG's shareholder, the Province of Ontario, also has an oversight role, through the Ministry of Energy, which has retained outside experts through Infrastructure Ontario to provide oversight and report back on findings.

The President and CEO of OPG, Jeff Lyash, appeared before the OEB twice in this proceeding – first at the presentation day on September 1, 2016 and then on the first two days of the oral hearing on February 27 and 28, 2017 – to speak to the importance of the DRP to the company and the company's efforts to ensure it is executed successfully. He explained:

> What incentive does OPG have to come in under budget? I think there is a layered set of incentives that we have, beginning with the fact that we're an Ontario business corporation, so, as part of that, we have an obligation, a fiduciary obligation, to run the company in a certain manner, and as part of that, our long-term objective is to satisfy our customers so that we're rewarded with net income and return on equity. Successfully completing this project on or under budget, on or under schedule, we believe substantially increases the company's potential to be successful in the long run.
>
> The second incentive I point out to you is that, in regard to Darlington, we're a regulated generating company, and part of the compact for being a regulated generating company is to deliver value to the customer. And that's at the heart of the value proposition for a regulated utility. It is for OPG. And so delivering projects ahead of schedule and under budget in a way that lowers the customer's price is part of our core objectives.
>
> The third element, I think, that provides us an incentive is that our shareholder in this case, unlike most other companies, are the citizens of Ontario. And so they, through the provincial government, own the company. And so, in defining what shareholder value we're delivering, ahead of schedule, under budget, and lowest customer price is what our

[40] Tr Vol 7 page 15.

> shareholder demands, and they exercise that through the Minister of Energy, and he has made that very clear.
>
> Another significant element here is that this is a destiny project for the company, and it is, frankly, a destiny project for the nuclear industry, and we're all very clear that meeting or exceeding expectations has tremendous value for the company and the industry in the long-term. This is also tied directly to management compensation, delivering not only the project but reliable and cost-effective operation of the units post-refurbishment.
>
> And then lastly – and I would ask Mr. Reiner to comment on this – we have built incentives down through the project management team and the contracts that we've structured.[41]

At the time the oral hearing began, at the end of February 2017, OPG advised that it was "tracking slightly under budget at this point in time, as of end of January, about $59 million".[42]

OEB staff submitted that OPG has planned effectively and that an appropriate framework has been implemented for DRP, but concurred with Mr. Roberts about execution phase risk. SEC's submission is similar:

> OPG appears to have tried their best to put in place project controls, a risk management framework, and a schedule that will ensure completion on time and on budget.
> All of this is a very positive sign. But it is only that. In no way does good planning guarantee successful execution.[43]

Proposed Additions to Rate Base

In this application, OPG asks the OEB to approve in-service additions to rate base for Unit 2 (the only unit planned to be completed in the test period) of $4,800.2 million in 2020 and 2021. In addition, OPG seeks approval for in-service additions of $377.2 million for other DRP-related projects, known as "campus plan projects", comprising the "early in-service projects", the facilities and infrastructure (F&I) projects, and the safety improvement opportunities (SIO) projects.[44]

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[41] Tr Vol 1 pages 37-38. March 2017 status reports were filed with Undertaking JT2.10
[42] Tr Vol 1page 16.
[43] SEC Submission page 42
[44] The early in-service projects are projects that will be placed in service before the refurbishment of Unit 2 is completed because they provide immediate benefit to the Darlington station even before Unit 2 is returned to service. The F&I projects are certain projects that OPG says are necessary to enable execution of the DRP, but which would be useful to the station even if the DRP were not completed. The SIO projects are initiatives that OPG committed to completed in the environmental assessment for the DRP that was approved by the CNSC, and would be useful to the station even if the DRP were not completed.

OPG is seeking approval of in-service additions to rate base associated with the DRP as set out in the following table:

Table 12
Bridge Year and Test Period In-Service Amounts ($ million)

	2016	2017	2018	2019	2020	2021	Total	Ex Campus Plan	Campus Plan
1 Original	350.4	374.4	8.9	0	4,809.2	0.4	5,543.3	4,800.2	743.1
2 Update		(365.9)		0			(365.9)		(365.9)
3 Net	350.4	8.5	8.9	0	4,809.2	0.4	5,177.4	4,800.2	377.2

Sources:

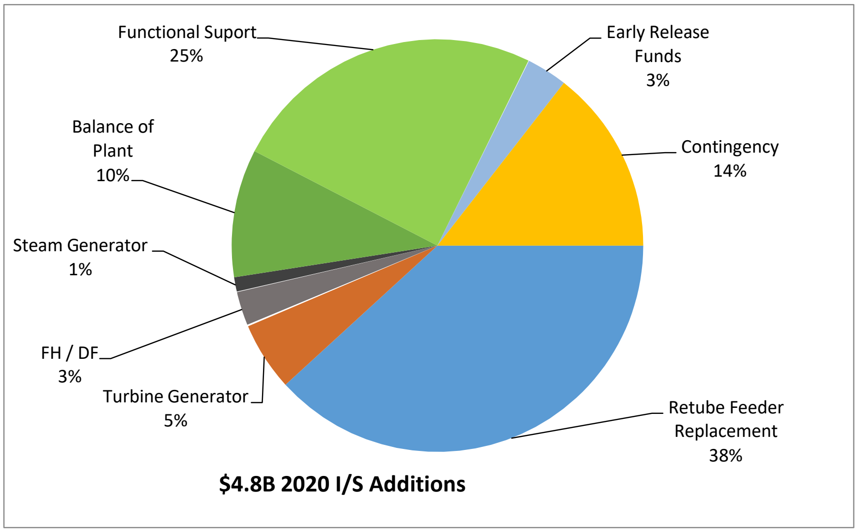
1. Original Request: Exh D2-2-1 page 6.
2. Update for removal of the Heavy Water Facility project (D2O project): Exh D2-2-10 Table 2 and Exh N2-1-1.
3. Net: Confirmed Tr Vol 1 pages 23 and 24 and Exh N2-1-1.

In an update to its original application,[45] OPG removed the Heavy Water Facility project (the D2O project), which will store large volumes of heavy water, but which has experienced delays and cost overruns. OPG testified that, despite these difficulties, the completion of the D2O project did not threaten the overall Unit 2 schedule and budget. Although some other DRP-related projects, including the Third Emergency Power Generator project, have also encountered delays or overruns, OPG did not seek to update the associated in-service amounts (and the timing of those amounts) as originally filed.

The Unit 2 in-service amounts are broken down as follows:[46]

[45] Exh N2-1-1.
[46] Exh D2-2-1 Figure 1.

Simplified Breakdown of Unit 2 In-Service Amounts[3]



Some parties proposed certain changes and reductions to OPG's requested in-service amounts. Several argued that the amount of contingency built into those amounts is too high. SEC argued that the updated Unit 2 Execution Estimate should be used as the basis for the OEB's approvals of the DRP-related in-service amounts.

In addition, there were objections to including the full $2.2 billion definition phase costs in the Unit 2 in-service amounts: (a) SEC argued that only half the definition phase planning costs, which exclude the other DRP-related facility costs, should be allocated to Unit 2; and (b) GEC argued that the definition phase costs cannot be determined as prudent at this stage as the costs would be too high in the event future units were cancelled.

Several parties commented on weak cost and schedule performance for F&IP and SIO projects, and submitted that the in-service additions related to the Third Emergency Power Generator project should be reduced; the proposed reductions ranged from $25 million to $40 million. On the basis of historical underspending, OEB staff submitted that project management and oversight costs for the test period should be reduced by 13%. OPG replied that the submissions are not supported by the evidence.

Some intervenors also claimed that the OEB is precluded by the terms of O. Reg. 53/05 from approving DRP costs on a forecast rather than a historical basis.

Contingency

The $12.8 billion DRP budget includes $1.7 billion of contingency. Of that amount, $694.1 million is attributed to Unit 2 and included in the $4.8 billion cost for that unit. This contingency is in addition to the contractor-level contingency built into some of the contracts.

OPG explained that it is understood by project management specialists that contingency funds are expected to be spent; they are not set aside as reserves to be drawn on only if the project goes off-course:

> [Contingency] refers to amounts that OPG anticipates spending because there are risk items and uncertainties that will occur and cannot entirely be mitigated or avoided. Contingency is included as a cost component of a project estimate just like any other component of a project. It is not an extra amount that will not be spent if the project goes as planned, nor is it a tool to compensate for an underdeveloped project plan. It is a necessary, legitimate and thoughtfully developed part of the estimated project cost based on residual (post-mitigation) risk and uncertainty.[47]

The higher the contingency, the higher the confidence level. In response to intervenor interrogatories, OPG provided the contingency amounts that would be associated with various confidence levels:

Table 13
Four Unit DRP Contingency Amounts

P level	Contingency	Reference
P99	$2.6 billion	L-4.3-15 SEC-027
P90	**$1.7 billion**	**D2-2-8 Attachment 1**
P70	$1.53 billion	L-4.3-12-OAPPA-008
P50	$1.4 billion	L-4.3-5-CCC-018, p.1

The DRP contingency amounts do not cover what OPG calls “low probability high consequence events”, such as “force majeure, a significant labour disruption, changes in the political environment, an international nuclear accident (Fukushima-type event) or incident, and unforeseen changes to financial and other economic factors beyond those assumed in the Program.”

[47] AIC page 53.

OPG described in some detail how it derived its contingency estimate for the DRP, using both qualitative and quantitative methods. This involved the development of a comprehensive risk register, which was vetted through "challenge sessions" of independent subject matter experts; the running of a "Monte Carlo simulation", which it described as "a computerized mathematical technique that replicates execution of the project thousands of times, accounting for potential realization of risk events and uncertainties"; consultation with outside experts (Palisade Corporation and KPMG); and review by OPG management.[48]

Both Dr. Galloway and Mr. Roberts testified that the level of contingency built into the DRP budget was appropriate.

Much of the cross-examination and submissions on the DRP focused on the amount of contingency built into OPG's cost forecasts. Some parties urged the OEB to approve in-service amounts for Unit 2 contingency based on a lower confidence level than P90.

AMPCO and CME supported the use of P90 for project planning and project approval. AMPCO submitted that this was the basis upon which the Ontario government has endorsed the DRP. However, OEB staff, AMPCO, CME and SEC submitted that contingency for project planning should differ from contingency for ratemaking. CME submitted that:

> … the use of a P90 estimate as the basis for rate recovery, in conjunction with Board approval of in-service rate base additions on a forecast basis is inappropriate, lacking in transparency, and creates a project spending relationship that is fundamentally contrary to the public interest.[49]

The Society and PWU fully supported the DRP as proposed by OPG and P90 contingency. The other parties proposed contingencies ranging from P37 to P50 and noted that any variances would be recorded in the CRVA. OPG argued that effective project planning leads to good ratemaking. The planning was undertaken not just to provide a conservative estimate to OPG's shareholder, but to ensure the success of DRP. OPG argued that P90 was developed probabilistically and was confirmed by Dr. Galloway and Mr. Roberts as best practice. Should the OEB approve a lower contingency, it should also approve the related earlier in-service date. In OPG's view, the CRVA is not a mechanism to defer revenue requirement.

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[48] Exh D2-2-7 pages 2-5.
[49] CME submission pages 33-34.

Findings

The OEB is only providing findings with respect to the DRP-related capital for which there are in-service amounts proposed for the test period, or for which amounts previously went into service and have not yet been approved. DRP-related capital expenditures associated with assets that are expected to come into service after the test period will be subject to a future proceeding. The OEB will not make any findings on those costs as part of this decision. In making its decision with respect of the DRP, the OEB has considered the overall planning, project management and oversight for the DRP, as an understanding of those activities is necessary to determine the reasonableness of the DRP-related capital additions for which OPG seeks approval as part of this proceeding.

The OEB accepts that the proposed capital additions for the DRP are reasonable. The OEB approves in-service additions to rate base associated with the DRP of $5,177.4 million as described in Table 12. This reflects approval of $4,800.2 million related to Unit 2 and $377.2 million associated with the campus plan projects (including all of the proposed contingency amounts). The OEB also accepts OPG's proposed methodology for calculating the rate base associated with the DRP-related capital amounts that are approved by the OEB.

There is no doubt that this is one of the largest projects the OEB has ever considered, but the analysis which the OEB used is no different than the fundamental considerations the OEB normally uses when considering capital projects. With need established by O. Reg. 53/05, the focus shifted to planning, risk and execution.

The OEB finds that the planning undertaken by OPG for the DRP was reasonable. The OEB notes that both experts agreed that the planning for the DRP had been conducted according to industry standards. The OEB finds that OPG has developed reasonable project control systems to manage the cost and schedule of the DRP. OPG also performed adequate risk assessment for the project and put in place processes to address risks as they arise.

The OEB also finds that the oversight structure that OPG has designed to monitor the DRP appears appropriate. As previously discussed, there are multiple layers of oversight with respect to DRP that should allow OPG to react appropriately to potential issues. The oversight for the project includes both internal and external expertise and resources.

However, as in the last payment amounts case, the OEB makes no specific finding on whether OPG's DRP contracting strategy or the resulting contracts were reasonable. The OEB is of the view that to specifically comment on such matters as contractual offramps, incentives for contractors and the management of risk as it relates to contractor performance would go beyond the OEB's scope in determining the DRP-related issues in this proceeding.

Overall, the OEB finds that OPG has implemented an appropriate structure based on its extensive planning efforts that provides it with the necessary capability to execute the DRP effectively. However, one of the challenges the OEB faces is that the nuclear industry is known for delivering projects over budget and beyond schedule. The OEB agrees with the parties and experts that strong planning does not assure successful execution.

The OEB notes that OPG considers the DRP a destiny project not just for the company but also for the nuclear industry at large. There is substantial pressure on OPG to complete the project successfully and deliver value to ratepayers. When asked about the incentives that OPG has to complete the project under budget, OPG responded that, as a regulated generation company, completing projects ahead of schedule and under budget is part of its core objectives. OPG also stated that its shareholders are the citizens of Ontario through the provincial government. Therefore, the shareholder demands that OPG deliver the DRP at the lowest possible customer cost. Management compensation is also directly tied to delivering the DRP successfully and providing reliable and cost-effective operation of Darlington post-refurbishment. Overall, the OEB finds that there are sufficient incentives, largely in terms of the long-term viability of the company, to execute the DRP successfully.

The OEB also notes, that as is discussed under Regulatory Framework, if Unit 2 is not completed on schedule and on budget, any costs in excess of the approved in-service amounts will be subject to a prudence review at the time the CRVA is brought forward for disposition. Therefore, if the project is completed over budget, the OEB will have the opportunity to review OPG's management of the execution phase of the project.

The OEB notes that OEB staff and intervenors made a number of arguments for specific changes and reductions to the in-service amounts requested by OPG as part of this proceeding. These arguments include: (a) the appropriate level of contingency; (b) the appropriate allocation of definition phase planning costs to Unit 2; (c) the appropriate in-service amounts related to the Third Emergency Power Generator; (d) the appropriate level of project management and oversight costs; (e) the use of the Unit 2 Execution Estimate as the basis for the OEB's approval; and (f) the constraints imposed by O. Reg. 53/05. The OEB does not agree with any of the arguments made by parties with respect to specific capital addition changes and reductions.

First, with respect to contingency, the OEB finds that the contingency budget proposed by OPG of $694.1 million related to the Unit 2 refurbishment is appropriate. The OEB notes that both experts agreed that a P90 confidence level was appropriate for a megaproject of this complexity.

In his testimony, Mr. Roberts asked why one would not want OPG to plan to a P90 factor. He stated that based on his expertise most projects do not have the luxury of getting to a P90, because they do not have the planning horizon (in this case 10 years) like OPG had. Mr. Roberts stressed that a P90 factor would provide more comfort that the project would come in on budget.

Some intervenors and OEB staff argued that basing rates on a P90 level was not appropriate. While planning to a P90 might be reasonable, rates should be determined based on a lower P-factor number, so that risk could be more fairly allocated as between OPG and ratepayers. Parties argued that for example, if rates were set based on a lower and less expensive P50 level, any costs beyond the P50 level would be subject to a prudence review. If the costs were lower than the P-level, then the amounts would be returned to ratepayers. Ratepayers would only pay actual costs. For its part, OEB staff suggested that the CRVA should be based on a P37 because that is what was used in OPG's own working schedule.

The OEB disagrees with these challenges to OPG's approach to contingency. The OEB accepts that P90 is a reasonable contingency factor for this project. The P90 factor was determined by OPG based on a statistical modelling of risks identified by OPG. As such, the P90 contingency amount should form part of the approved DRP-related in-service amounts. The OEB does not agree with the argument put forth by some parties that the contingency level should be set differently for planning and ratemaking purposes. The OEB finds that if setting a contingency budget at a P90 level is appropriate from a planning perspective it is logical that it is also appropriate to approve that level of contingency for recovery in rates.

The outcome of the argument that a lower contingency amount should be used for the purposes of ratemaking is that the CRVA could in the end, depending on the amount of contingency budget actually spent, be used as mechanism to defer the recovery of amounts reasonably spent by OPG. The OEB finds that the CRVA is not a mechanism by which to defer payment. To the extent deferral of payment impact is required; it should be done through the smoothing mechanism as prescribed.

On the issue of the appropriate allocation of the definition phase costs as between the multiple DRP units, the OEB finds that it is appropriate to include the definition phase costs in the in-service amounts as proposed by OPG. The OEB finds that the definition phase costs related to certain projects that are common to the refurbishment of multiple units are properly included in rate base as proposed by OPG as they are used and useful at the time they enter service. With respect to the definition phase planning costs, the OEB agrees with OPG that these costs were incurred to permit Unit 2 refurbishment and therefore are properly included in rate base along with Unit 2 as proposed by OPG.

In regard to the argument made by some parties that the proposed in-service additions related to the Third Emergency Power Generator should be reduced, the OEB disagrees. The OEB agrees with OPG that the proposed disallowance suggested by parties is based only on the notion that there has been a variance from the initial project budget and the parties presented insufficient evidence to support the disallowance.

With respect to OEB staff's submission that the project management and oversight costs for the test period should be reduced by 13%, the OEB dismisses this argument. The OEB finds that OEB staff's argument does not consider the importance of the functions which the disallowance would impact.

The OEB is of the view that it is not necessary to use the Unit 2 Execution Estimate as the basis for its approvals. The OEB notes that the CRVA will operate to capture any revenue requirement impacts of changes to in-service dates and in-service amounts between OEB-approved and actual. Therefore, using the in-service amounts and dates as proposed by OPG is reasonable.

Finally, some intervenors argued that O. Reg. 53/05 requires the OEB to review the prudence of DRP costs after the costs have been incurred, rather than on a forecast basis. GEC submitted that the OEB should only approve DRP costs already incurred, while other parties submitted that the OEB could include forecast costs as a placeholder with a final determination on prudence to be made in another case.

Section 6(2)4 of the regulation states that the OEB "shall ensure" that OPG recovers its capital and non-capital costs and firm financial commitments incurred in respect of the DRP if the OEB "is satisfied that the costs were prudently incurred and that the financial commitments were prudently made". It is within that context that the OEB is asked to consider whether the proposed capital expenditures and/or financial commitments for the DRP are reasonable.

The OEB rejects the argument put forward by some parties that the regulation precludes the ability of the OEB to consider forecast costs for DRP in the revenue requirement and must instead engage in a retrospective review. Although intervenors are correct that section 6(2)4 speaks of costs that <u>were</u> prudently incurred (and financial commitments that <u>were</u> prudently made), the OEB does not accept the argument that the prudence of CRVA eligible costs must be determined after the costs are incurred.

This interpretation of the regulation is not consistent with the approach the OEB has taken in the past. When the OEB considers dispositions of the CRVA balances, it will review the variances from the forecast and actual amounts and will make a determination of prudence on the actual amounts over forecast. The OEB sees no reason to change its approach for the DRP. To do so would frustrate the purpose of the regulation.

Parties raised the argument that due to the way the CRVA was set up, OPG could undertake some spending that was not prudent, however so long as the total Unit 2 cost was less than $4.8 billion, the OEB would have no way to track and disallow that imprudent spending. The OEB recognizes that this risk exists, as it does with spending on any large project. The OEB finds that this risk is mitigated by the fact that in that event, underspending will have to occur in some other areas of the project to achieve the overall budget. OPG also does not deny that "imprudent costs could occur if the right actions are not taken."[50] It is for this reason that the OEB has carefully considered OPG's proposed budget for DRP and satisfied itself that the proposed $4.8 billion budget is appropriate.

For all of the above reasons, the OEB does not agree with the arguments made by parties for reductions to the in-service amounts. The OEB approves the in-service amounts for Unit 2 and the campus plan projects as proposed by OPG.

The OEB adds that OPG has planned a staggered approach – Unit 2 will be completed before the refurbishment of the next unit begins. The OEB expects that there will be unit over unit efficiencies. This expectation is consistent with OPG's position that it will benefit from "lessons learned" on each unit.

5.3.2 Treatment of DRP Costs in the CRVA

OPG OPG proposed that if actual additions to rate base are different from forecast amounts, the cost impact of the difference would be recorded in the CRVA, and any amounts greater than the forecast amounts added to rate base would be subject to a prudence review in a future proceeding. OPG's position is that the success of the Unit 2 refurbishment (including the campus plan projects) should be measured on a total envelope basis. That is, as long as Unit 2 is completed at or under the total $4.8 billion budget (and the campus plan projects are completed on budget), there would be no further prudence review of Unit 2 spending.

[50] OPG Reply Submission page 58.

Some parties suggested a more granular approach, where there would be a prudence review, on a component-by-component basis, of all variances recorded in the CRVA – even if the overall budget was met because overruns on one component were offset by savings on another. In this manner, the OEB would ensure that each component of the DRP is considered prudent on a standalone basis.

OEB staff also proposed that amounts earned in excess of the OEB-approved ROE during the test period be used to offset the revenue requirement associated with DRP-related cost overruns.

Findings

The OEB rejects the argument by OEB staff and some intervenors that a future assessment of amounts in excess of the forecast costs (through the CRVA) should be done on a component-by-component basis.

In its submission, OEB staff asks OPG to provide, as part of the draft payments order process, a detailed list of all the components of the Unit 2 refurbishment and a list of campus plan projects (over $5M) for which there are in-service amounts applied for as part of this proceeding. The OEB will not require OPG to provide component-by-component reporting. It is the OEB's expectation that OPG will deliver the DRP project on time and on budget. In doing so, the OEB will not make orders that would seek to constrain OPG's ability to execute the project as necessary. The RRF speaks to an outcomes based approach. The OEB will not micromanage the DRP, but rather will hold OPG accountable to deliver the DRP on time and on budget. If OPG were to face CRVA scrutiny for each component part of the Unit 2 project, it may lead to unintended consequences and lessen the ability of OPG to deal with issues as they arise. As OPG argues convincingly in its reply submission, the refurbishment of Unit 2 is a single integrated project, not a web of independent projects. It must be managed on a holistic, dynamic basis, where "higher cost may be incurred in one area to address a risk or resolve an issue in another area, which, when taken as a whole, is to the benefit of ratepayers."[51] At the end of the day, it is OPG's responsibility to deliver the Unit 2 project (and the campus plan projects) within the budget envelope approved in this proceeding (that is, the approved in-service amounts of $4,800.2 million for Unit 2 and $377.2 million for the campus plan projects). OPG should have some flexibility in doing so.

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[51] Reply Argument page 60.

Still, to be clear, the OEB will closely scrutinize any exceedances above the approved in-service amounts in subsequent proceedings. OPG will not be made whole through the CRVA unless it can demonstrate that the exceedances were prudent. And the OEB will look carefully at any DRP-related assets that may be reclassified as non-DRP (that is, anything that is moved from the DRP umbrella to the general nuclear umbrella), just as it looked carefully in this proceeding at the AHS and OSB projects.

With regard to OEB staff's argument that amounts earned in excess of the OEB-approved ROE during the test period be used to offset the revenue requirement associated with DRP-related cost overruns, the OEB does not agree. OPG has included an off-ramp proposal to deal with the situation (which has never happened before) where OPG over-earns its allowed ROE.[52] The OEB is satisfied with this proposal.

5.3.3 DRP OM&A

OPG requested OEB approval of the following OM&A expenditures related to the DRP during the test period:

Table 14
DRP OM&A Expenditures

($ million)	2017	2018	2019	2020	2021	Total
DRP OM&A	41.5	13.8	3.5	48.4	19.7	126.9

These expenditures are mainly removal costs associated with the replacement of existing assets and the disposal of Low and Intermediate Level Waste variable expenses related to disposal costs (based on the volume of waste).

DRP-related OM&A spending, like capital spending, would be subject to CRVA treatment.

There were no submissions filed opposing the level of DRP OM&A expenditures.

[52] Under this proposal, an OEB review may be initiated where OPG's actual ROE is outside ±300 basis points of its allowed ROE. See section 8.1.7 of this Decision.

Findings

None of the parties objected to the levels of DRP OM&A listed in Table 14. The OEB accepts OPG's proposal in this regard.

5.3.4 DRP Reporting

OPG proposed to provide annual reports to the OEB on its DRP progress. OPG originally proposed that the scope of the annual reports would entail the following:

Table 15
Original Proposed DRP Annual Report

Category	Measure
Progress	• Key Achievements • % Complete
Safety	• All Injury Rate
Quality	• Quality Compliance (metrics to be determined)
Cost	• Cost Performance Index • Life-to-date cost • Forecast to Complete • Estimate at Complete
Schedule	• Schedule Performance Index • Status of Key Milestones • Critical Path Progress • Forecasted Completion Dates

As conceived by OPG, the annual reports would be for informational purposes, "not for purposes of project management or to determine the DRP's future."[53]

Some parties argued that more robust and more frequent reporting should be required, and pointed to the generic reporting template provided by Mr. Roberts as a good model.[54] OEB staff submitted that more detailed reporting would assist the OEB with its review of applications for disposition of CRVA balances. One party, Energy Probe, suggested that the OEB consider "a more aggressive form of reporting, which may entail an independent auditor that reports to the OEB on an annual basis."[55]

In its reply submission, OPG agreed to add some of the elements of the Roberts template to its proposed report, but maintained that other elements were unnecessary.[56]

[53] Reply Argument page 224.
[54] Undertaking J7.1.
[55] Energy Probe Submission page 18.
[56] Reply Argument pages 227-228.

OPG's revised reporting proposal is shown below, with the italics denoting those elements that were not included in its original proposal:

Table 16
Revised Proposed DRP Annual Report

Category	Measure
Introduction and Table Contents	N/A
Executive Summary	N/A
Overall DRP Status	• *High level overview of the DRP itself*
Progress	• Key Achievements • % Complete
Safety	• All Injury Rate • *Lost hours due to injuries* • *Explanation of any safety programs/initiatives launched by OPG/contractor*
Quality	• # of Significant Field Rework Events
Cost	• Cost Performance Index • Life-to-date cost • *Actual versus forecast cumulative capital costs* • Forecast to Complete • Estimate at Complete
Schedule	• *Current schedule performance* • Schedule Performance Index • Status of Key Milestones • Critical Path Progress • Forecasted Completion Dates
Engineering	• *Summary of engineering status and key issues*
Procurement	• *Summary of procurement status and key issues*
Construction	• *Summary of construction progress and analysis of any material variances from plan* • *Summary of any material labor issues* • *Summary of any material environmental issues*
Testing, Start-Up and Commissioning	• *Summary of systems tested, commissioned, restarted, and any material key results and issues*
Program Risks and Risk Management	• *Key risks and mitigation* • *Key issues and corrective actions*
Staffing	• *Actual staffing levels against plan* • *Changes to staffing plan* • *Efforts to fill open positions*

OPG reiterated in its reply that reporting on an annual basis would be sufficient to allow the OEB to track the progress of the DRP. Quarterly reporting, as proposed by some intervenors, would impose a “significant burden” on the program and on the company, and would make it more difficult to spot trends, since the incremental change from report to report would be minimal. OPG further argued that Energy Probe’s proposal for an independent auditor reporting directly to the OEB was unnecessary in light of the extensive monitoring and oversight already built into the DRP.

Findings

The OEB accepts OPG’s proposal in respect of DRP reporting, as revised in its reply submission. The level of detail as set out in Table 16 and frequency of reporting (annual) will provide the OEB with meaningful updates on the program’s progress – and provide an early warning system if the program starts going off-plan – without being unduly onerous for OPG.

The OEB will not require an independent auditor as proposed by Energy Probe. The OEB heard evidence on the various layers of reporting and oversight that already exist, both internal (e.g. OPG’s Internal Audit and Nuclear Oversight groups) and external (e.g. the Refurbishment Construction Review Board described previously and the independent advisor that reports to the Ministry of Energy). Adding another oversight body is not necessary.

5.4 Nuclear Benchmarking

Nuclear performance benchmarking has been an important function for both OPG and the OEB for many years. OPG’s Memorandum of Agreement with its shareholder (Schedule C) includes a requirement for it to undertake benchmarking analysis, and the OEB has spoken of the importance of benchmarking in every payment amounts application. The OEB’s Renewed Regulatory Framework also highlights the importance of benchmarking. OPG has stated that it is committed to “continuous improvement” in its benchmarking results.[57]

OPG’s current approach to nuclear performance benchmarking was implemented in 2009 and has formed a key component of every payment amounts application since that time. OPG uses a top-down, gap-based nuclear planning process that was developed by ScottMadden Management Consultants (ScottMadden). Using

[57] Tr Vol 13 pages 3-4.

ScottMadden's methodology, OPG benchmarks itself annually against other North American nuclear operators on 20 measures. Of these 20, three have been identified as "key metrics": total generating cost (TGC), which is the "all-in" cost for generating electricity expressed on a $/MWh basis; the Nuclear Performance Index (NPI), which is a weighted composite of ten safety and performance indicators; and Unit Capability Factor (UCF), which measures a plant's actual output as a percentage of its potential output over a period of time.[58]

A summary of OPG's historical, current, and forecast benchmarking results is provided in Table 17, Summary of Nuclear Benchmarking Reports, below:

[58] Tr Vol. 13 pages 8-10.

Summary of Nuclear Benchmarking Reports

	---Rolling Actual Results---								--Annual--				
	a	b	c	d	e	f	g	h	i	j	k	l	m
	2008	2009	2010	2011	2012	2013	2014	2015	2016 Target Exh A2	2017 Target Exh A2	2016 Forecast Exh N1	2017 Target Exh N1	2014 "Scott Madden" Phase 2 Report
Darlington													
WANO NPI (Index)	95.67	95.10	94.10	92.80	96.30	90.80	92.10	83.70	87.30	84.30	85.50	83.10	98.60
2-Year Unit Capability Factor (%)	91.99	90.20	89.40	89.60	92.00	90.44	89.41	83.96	91.10	85.10	90.00	85.10	93.30
3-Year Total Generating Costs ($/New MWh)	30.08	32.77	33.55	33.05	31.67	34.42	37.73	44.38	47.35	47.85	46.47	49.75	36.75
Pickering													
WANO NPI (Index)	60.90	67.17	64.30	66.10	64.70	67.50	64.30	68.50	72.30	71.10	75.60	69.70	77.83
2-Year Unit Capability Factor (%)	67.65	74.47	74.57	72.50	75.62	75.77	74.50	77.32	77.60	71.50	75.30	71.50	82.10
3-Year Total Generating Costs ($/New MWh)	67.05	66.42	65.62	65.86	67.16	67.18	67.93	67.36	71.09	76.48	72.46	78.83	66.84
Pickering A													
WANO NPI (Index)	60.84	61.10	47.70										70.90
2-Year Unit Capability Factor (%)	56.60	58.00	63.30										84.30
3-Year Total Generating Costs ($/New MWh)	92.27	95.41	90.21										70.81
Pickering B													
WANO NPI (Index)	60.93	70.20	72.60										81.30
2-Year Unit Capability Factor (%)	73.17	77.70	80.20										81.00
3-Year Total Generating Costs ($/New MWh)	58.68	54.64	54.79										64.80

(green)	Q1
(white)	Q2
(yellow)	Q3
(red)	Q4

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

As filed with Applications

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

Several parties argued that OPG's overall rankings on the three key metrics are poor (bottom quartile) and are not improving, and that OPG has not hit the targets that it set for itself. Parties noted that OPG's relatively poor performance, particularly in the TGC metric, meant that ratepayers were paying unreasonably high amounts for the electricity produced. OPG responded that its overall results were brought down by Pickering, which has smaller unit sizes and older technology than the comparators. It noted that Darlington has much stronger performance, and that the forecast "dip" in Darlington's performance in 2015 and 2016 is largely the result of the 2015 vacuum building outage, primary heat transport motor replacements and reduced production resulting from the DRP.

OPG produced what it referred to as "normalized" forecast results for Darlington. Although production from Darlington will be significantly reduced on account of the DRP, for the purposes of calculating its performance in the key metrics OPG assumed that production would in fact stay at historic levels. In OPG's view this produces results that are better reflective of its actual performance. OEB staff and several intervenors criticized this, noting that OPG did not consult with ScottMadden when it developed its approach to normalization.

Findings

Benchmarking assists the OEB with its review of applications. The Rate Handbook states that, "With the Custom IR rate setting options, a utility can customize the rate setting mechanism for their specific circumstance. Given this flexibility, the OEB will place greater reliance on benchmarking evidence for a Custom IR application to assess proposals over the five year term."[59] The OEB reviews the nuclear operations benchmarking in this section of the Decision. The review of the Goodnight staffing benchmarking, Willis Towers Watson compensation benchmarking and Hackett Group Corporate Support benchmarking are elsewhere in this Decision. The OEB finds that the filing for these independent benchmarking reports is informative and aligned with Custom IR.

OPG has been benchmarking the performance of its nuclear facilities against other North American nuclear operators for many years. While OPG prepares the nuclear operations benchmarking itself, it is done in accordance with the methodology first established by ScottMadden in 2009, and was reviewed by ScottMadden for this

[59] Handbook for Utility Rate Applications, page 18.

application.[60] The OEB finds that the methodology is appropriate with the exception of OPG's normalization proposal for the test period, as discussed in section 5.4.

OPG's nuclear operations benchmarking results have been a concern to the OEB since it began regulating OPG in 2008. In all three previous cost of service cases the OEB has noted OPG's poor performance relative to its peers, and has made disallowances at least partially on account of this.

The OEB recognizes that benchmarking is a tool that provides insight into relative cost and performance, but that it has limitations. No two businesses operate in identical environments, whether it be because of different technologies, different regulatory regimes, different jurisdictions, or any number of other potential differences. Benchmarking is therefore not the only factor that the OEB considers in setting payment amounts. Benchmarking does, however, offer a strong high-level picture of an enterprise's overall performance – this is why the OEB, OPG and the provincial government have all been strong supporters of benchmarking for many years. This is especially true when there are many years of benchmarking data prepared using the same methodology.

As part of its initial work with ScottMadden, in 2009 OPG set targets for itself for the three key metrics that both OPG and ScottMadden believed could be achieved by 2014. In preparing this application OPG also set targets for the years 2016-2019. All of the benchmarking results for the three key metrics since 2008 and the targets that were set for 2014 and 2016-2017 were summarized in a chart prepared by OEB staff, which is reproduced above.

Since OPG began benchmarking using the ScottMadden methodology, its overall results have been very poor. Since 2008 its ranking for each of the three key metrics has been either at or near the bottom in every year. Both the OEB and OPG expect better than this, and ratepayers should expect better too.

OPG argues that its poor results are driven to a large extent by the Pickering units. Pickering's performance is hampered by its small unit size, first generation CANDU technology, and low capability factor attributable to the extensive planned outage program that is required to extend its operating life. The Darlington units perform much better, generally achieving first or second quartile results over much of this period. There was a drop-off in performance in 2015 (where Darlington in fact had its worst results since ScottMadden benchmarking began), which OPG argues is on account of a vacuum building outage (VBO) and aging plant equipment, refurbishment support and

[60] Exh F2-1-1 Attachment 3.

regulatory requirements to extend the life of the facility. OPG argues that its two facilities should be considered separately, and not as a whole.

The OEB accepts that given the vintage of the Pickering station it is not realistic to expect top quartile performance. It also understands that Darlington's performance in 2015 was impacted to some extent by the VBO and possibly other challenges. The long term unit outages at Darlington that are scheduled during the test period also make benchmarking forecasting and target setting challenging.

In spite of this, OPG's benchmarking performance remains below the OEB's expectations. In terms of the benchmarking data, Pickering ranked 59 out of 64 nuclear plants in North America for the 2015 three-year TGC. Although this is impacted by the factors described above, it is not acceptable.

In 2009 OPG set targets for Pickering's performance (as well as Darlington's) that it expected to achieve by 2014. Both OPG and ScottMadden believed these targets to be attainable. OPG failed to achieve any of these targets. OPG had targeted second quartile performance and an overall rating of 77.83 for NPI (actual result: fourth quartile and 64.30), third quartile and a rating of 82.10 for UCF (actual result: fourth quartile and 74.50), and fourth quartile and a cost per MWh of $66.84 (actual result: fourth quartile and $67.93 per MWh). OPG's most recent targets for 2017 remain below what it initially expected to achieve by 2014. Despite the challenges of operating an older facility, OPG is responsible for Pickering's performance and should be expected to achieve at least its own performance targets. OPG set its targets with full knowledge of the facility and its condition. Despite that, OPG has continuously failed to meet its own targets. Having set the target, the OEB expects OPG to achieve it or very close to it.

Although Darlington certainly has much stronger performance, OPG also failed to achieve the 2014 targets it set for itself in 2009. OPG had targeted top quartile performance and an overall rating of 98.60 for NPI (actual result: second quartile and 92.10), top quartile and a rating of 93.30 for UCF (actual result: second quartile and 89.41), and top quartile and a cost per MWh of $36.75 for TGC (actual result: top quartile and $37.73/MWh. As noted above, OPG's Darlington performance for 2015 was in fact materially worse than its 2014 performance. The VBO accounts for part of this dip in performance; however as TGC is calculated on a three-year rolling average it cannot explain such a marked change on its own.

SEC has also pointed out that OPG rarely actually achieves the benchmarking targets that it sets for itself. SEC provided a table comparing the targets that had been set in OPG's business plans for the years 2013 through 2016, and the actual results that were achieved. In more cases than not, OPG failed to hit its business plan targets.[61] In the period 2013 to 2015, OPG did not meet the NPI, UCF or TGC targets set for Pickering and Darlington, except for one instance – the NPI for Pickering in 2013. In 2016, OPG has met half the targets it set for the key measures.

Over the test period OPG's results for the key metrics are forecast to get worse. TGC is expected to increase steadily for both facilities through much of the test period. OPG's forecast results for Darlington during the test period are complicated by the DRP, which will see several units off-line for extended periods of time (either one or two units will be off-line in each year of the test period). OPG sought to "normalize" its Darlington TGC results by making adjustments to account for this lost production. It did this by inflating the denominator in the TGC equation (i.e. production in MWh) to the level it would have been at had the units under refurbishment not been out of service. The results presented in the business plan and N1 update, therefore, are not the actual TGC numbers that OPG expects to achieve; they have been "normalized" pursuant to OPG's methodology. Normalizing the data materially improves the results. Curiously, OPG did not consult with ScottMadden prior to making this adjustment, even though the original methodology had been created with ScottMadden. OPG did seek ScottMadden's opinion after the fact. ScottMadden's after the fact opinion offers, at best, very qualified support for OPG's normalization methodology, and suggests there would be preferable means of accounting for the impact of the DRP. The TGC figures are of course substantially higher (i.e. worse) if not normalized.

Regardless of whether OPG's approach to normalization is employed, the benchmarking results for both Pickering and Darlington (and therefore OPG's overall results as well) do not show continuous improvement. Indeed it is questionable if there is any overall improvement relative to OPG's peers at all, and in some areas OPG's performance appears to be getting worse. OPG must continue to work to improve its performance.

The OEB agrees with the submission of SEC that OPG should be required to report TGC on a normalized and non-normalized basis.[62]

The OEB's review of OPG's nuclear benchmarking performance is further reflected in the findings in the following sections of this Decision: Nuclear OM&A, Custom IR, Compensation and Pickering Extended Operations.

[61] SEC Submission pages 72-73.
[62] SEC Submission page 74.

The OEB expects OPG to file a review from ScottMadden regarding OPG's nuclear benchmarking methodologies with its next cost based application.

5.5 Nuclear Operating Costs

The following table summarizes the historical and test period nuclear operating costs:

Table 18: Nuclear Operating Costs

Line No.	Cost Item	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	OM&A:									
	Nuclear Operations OM&A									
1	**Base OM&A**	1,127.7	1,127.1	1,159.6	1,201.8	1,210.6	1,226.0	1,248.4	1,264.7	1,276.3
2	**Project OM&A**	105.7	101.9	115.2	98.2	113.7	109.1	100.1	100.2	86.8
3	**Outage OM&A**	277.5	221.3	313.7	321.2	394.6	393.8	415.3	394.4	308.5
4	**Subtotal Nuclear Operations OM&A**	1,510.8	1,450.3	1,588.5	1,621.3	1,718.9	1,728.9	1,763.8	1,759.4	1,671.6
5	**Darlington Refurbishment OM&A**	6.3	6.3	1.6	1.3	41.5	13.8	3.5	48.4	19.7
6	**Darlington New Nuclear OM&A**[1]	25.6	1.5	1.3	1.2	1.2	1.2	1.2	1.3	1.3
7	**Allocation of Corporate Costs**	428.4	416.2	418.8	442.3	448.9	437.2	442.7	445.0	454.1
8	**Allocation of Centrally Held and Other Costs**[2]	413.5	416.9	461.0	331.9	80.2	118.2	108.3	91.1	81.3
9	**Asset Service Fee**	22.7	23.3	32.9	28.4	27.9	27.9	28.3	22.9	20.7
10	**Subtotal Other OM&A**	896.5	864.1	915.5	805.0	599.7	598.3	584.1	608.6	577.1
11	**Total OM&A**	2,407.3	2,314.5	2,504.0	2,426.3	2,318.6	2,327.1	2,347.9	2,368.0	2,248.7
12	**Nuclear Fuel Costs**	244.7	254.8	244.3	264.8	219.9	222.0	233.1	228.2	212.7
	Other Operating Cost Items:									
13	**Depreciation and Amortization**	270.1	285.3	298.0	293.6	346.9	378.7	384.0	524.9	338.1
14	**Income Tax**	(76.4)	(61.5)	(31.8)	(18.7)	(18.4)	(18.4)	(18.4)	51.2	51.7
15	**Property Tax**	13.6	13.2	13.2	13.5	14.6	14.9	15.3	15.7	17.0
16	**Total Operating Costs**	2,859.3	2,806.2	3,027.8	2,979.4	2,881.6	2,924.4	2,961.9	3,187.9	2,868.2

Source: Exh F2-1-1 Table 1

Each element of nuclear operating cost is reviewed in the subsequent sections of this Decision except Asset Service Fee (line 9), which was fully settled by the parties. Similarly, there was partial settlement on nuclear fuel expense (line 12). The parties agreed to a 2% downward adjustment to the nuclear fuel bundle unit cost forecast in each year of the Custom IR term relative to the forecast in the Application. The impact of production forecast and fuel oil costs were unsettled. As the OEB has approved OPG's proposed production forecast and as there were no submissions on fuel oil costs, OPG shall reflect the adjustment to nuclear fuel bundle unit cost in the draft payment amounts order.

Elements of nuclear operating cost are also reviewed in section 8.2, Nuclear Custom IR. OPG's application proposed a stretch factor on base OM&A (line 1) and corporate allocated costs (line 7).

Overall Findings Regarding Nuclear Operating Costs

The OEB has determined that it will reduce the proposed test period nuclear operating expenses by a base amount of $100 million per year. The basis for this disallowance is described in further detail below, but the chief areas of concern are base OM&A, excessive compensation (including pensions), and excessive nuclear allocated corporate costs. The OEB's decision is also informed by OPG's nuclear benchmarking results. In addition, the OEB will not allow the costs related to the Fitness for Duty costs ($41 million over five years), although the OEB will allow OPG to track any costs for this program through a deferral account for review and disposition at a later date. The OEB will also be applying a stretch factor of 0.6% (as opposed to the 0.3% requested by OPG) to base, outage, project and allocated corporate OM&A. The reasons for these reductions are discussed below.

The OEB recognizes that there is some amount of overlap between some of the areas where it has identified excessive costs, in particular between compensation and allocated corporate costs. The OEB has taken this into account in reaching the $100 million figure. The evidence supports a range of disallowances under different categories which in theory could have supported disallowances that could total much greater than $100 million. In reaching a final number the OEB has sought to balance the interests of ratepayers in not paying an unreasonable amount, and OPG's needs to fund its nuclear operations.

5.6 Nuclear Operations OM&A

The historical and test period OM&A expenses for the operation and maintenance of the nuclear facilities is summarized in the following table. The expenses do not include the OM&A increases reflected in the Exh N1-1-1 Impact Statement, namely changes for forecast pension and other post-employment benefits (OPEB) cash amounts and an increase in base OM&A resulting from new Fitness for Duty requirements from the CNSC.

Table 19: Nuclear Operations OM&A

$million	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2016 Actual	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Base OM&A										
Labour (Regular and Non-Regular)	832.4	827.1	834.0	844.7	807.2	859.0	846.9	874.3	885.0	887.9
Overtime	48.6	46.7	54.5	47.8	63.7	46.4	46.5	46.1	47.4	47.8
Augmented Staff	3.1	3.6	4.4	3.3	6.7	4.5	3.5	3.0	2.6	1.6
Materials	85.1	73.4	83.4	70.5	81.7	68.4	68.2	68.5	71.1	70.8
Licence	34.2	32.6	34.5	36.4	36.0	37.2	38.7	39.6	40.2	40.6
Other Purchased Services	100.0	98.7	108.4	164.1	129.1	161.1	185.1	180.8	178.3	187.3
Other	24.3	44.9	40.3	35.0	58.0	34.2	37.0	36.2	40.2	40.3
Total Base OM&A	1,127.7	1,127.0	1,159.5	1,201.8	1,182.4	1,210.8	1,225.9	1,248.5	1,264.8	1,276.3
Project OM&A	105.7	101.9	115.2	98.2	89.3	113.7	109.1	100.1	100.2	86.6
Outage OM&A	277.5	221.3	313.7	321.2	306.7	394.6	393.8	415.3	394.4	308.5
Operations OM&A	1,510.9	1,450.2	1,588.4	1,621.2	1,578.4	1,719.1	1,728.8	1,763.9	1,759.4	1,671.4

Source: Exh F2-1-1 Table 1, Exh F2-2-1 Table 2, Undertakings J14.2 and J14.3

While 2016 actual operations OM&A was below budget, OPG states that its forecast for the test period is necessary to execute additional work and is relatively flat over the five-year period. The application states that base OM&A increases are related to labour and material cost escalation. OPG has proposed that the Custom IR stretch factor apply to base OM&A and allocated corporate OM&A (section 5.8 of this Decision).

Project OM&A expenses include both portfolio (managed by the Asset Investment Screening Committee) and non-portfolio projects. The two non-portfolio projects in the test period are the Fuel Channel Life Extension Project and Pickering Extended Operations. In the period 2017 to 2020, $57.6 million of project OM&A is forecast for PEO.[63]

The expenses related to planned outages are recorded under outage OM&A, and vary year over year depending on the number and scope of the planned outages. Darlington units are scheduled for outages every three years and Pickering units are scheduled for outages every two years. The application states that, “While there are many standard elements included in the outage scope, there can also be unique activities, programs or major equipment campaigns that are unit-specific.”[64] The resources for outages are provided by a mix of regular, non-regular and augmented staff, as well as overtime and purchased services. The increase in outage OM&A forecast for 2017 is related to work on Darlington Unit 2 that is in addition to and separate from Unit 2 refurbishment work. OPG states that outage OM&A costs are stable until 2021, when costs drop because there are no planned outages for Darlington in 2021. In the period 2017 to 2020, $233.7 million of outage OM&A is forecast for PEO.

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[63] Exh F2-2-3 page 6, Chart 2, Total proposed PEO project OM&A is $61.6 million; $4 million in 2016.
[64] Exh F2-4-1 page 6.

OEB staff and several intervenors proposed base OM&A and outage OM&A reductions generally based on historical under-spending. OEB staff submitted that fewer operating units during refurbishment and the use of swing staff from operations to DRP supported reductions in base OM&A. With respect to 2016 variances, the PWU submitted that the actual base OM&A labour expense was the lowest it has been historically and was an anomaly. None of the intervenors supported the $41 million expense related to the Fitness for Duty employee drug, alcohol, psychological and physical testing as the timing of the requirements is uncertain.

Findings

Nuclear OM&A is divided into a number of categories. The largest single subset of those costs is nuclear operations OM&A, which are the OM&A costs incurred for the normal operations of the nuclear stations. Nuclear operations is further divided into base, project, and outage OM&A. Over the course of the test period OPG has forecast these expenditures to be approximately $1.7 billion per year, which is around 60% of OPG's total forecasted nuclear OM&A.

Base OM&A is the single largest category of OM&A, averaging around $1.25 billion per year over the test period. Much of this expense relates to staff labour costs (including overtime).

A number of parties argued in favour of disallowances specifically to base OM&A (usually in addition to separate disallowances that were sought under compensation, which as noted has significant overlap with base OM&A). The arguments focused on excessive overtime costs, high purchased services costs, and questions as to why base OM&A costs were not going down in years when one or two Darlington units were to be out of service.

OPG responded that it had justified all of its proposed expenditures, and that in some cases parties were seeking a double disallowance (for example by seeking disallowances for the same thing under compensation and also under base OM&A).

The OEB will disallow $25 million per year on account of the forecast base OM&A expenses being higher than the actual spending that OPG is likely to incur.

The OEB agrees with OPG that base OM&A should be considered as a whole and not on the basis of its individual components. As OPG explained, various base OM&A components can be substituted for one another.[65]

In recent years, OPG has had difficulty spending its entire base OM&A budget for overtime, augmented staff, and other purchased services. These services are used as required to supplement Labour (Regular and Non-regular). OPG does not propose to reduce the amount spent on Labour in the base OM&A budget but at the same time does propose substantial increases to combined overtime, augmented staff and purchased services categories. OPG's evidence was that these three should be considered together as they all supplement Labour – which one is actually used depends on the particular situation.

In four of the last five years, OPG has underspent its budget for these categories. OPG has never spent a combined total of $200 million on these categories (the average actual spend was approximately $163 million from 2012-2016); however it is proposing to spend well over $200 million in each of the test years (as much as $235 million in 2018).[66] Given OPG's difficulties in spending to its budget in recent years, plus the very significant personnel demands that will result from other projects such as DRP (which are not part of base OM&A), the OEB does not believe that OPG's budgets for the test period are realistic. It will therefore disallow $25 million annually. The OEB finds that this reduction does not overlap with the separate findings on compensation as none of the payments for overtime, augmented staff or purchased services are relevant to the findings on compensation.

Outage OM&A is comprised of incremental labour, services and materials required to complete OPG's planned outages, along with inspection and maintenance services regular staff labour. Outage OM&A expenses are forecast to be in the $400 million range from 2017-2020, and then drop off to $308 million in 2021. $233 million of the total test period outage OM&A costs are for the PEO project.

Several parties argued for disallowances to outage OM&A, ranging from around $19 million per year to $54 million per year. The arguments focused on OPG's historic underspend on outage OM&A, and spending on some Darlington units that will be out of service on account of the DRP (the costs for which are accounted for separately).

OPG responded that ordinary outage work was still required during the DRP, and that it is in fact doing the work that ordinarily would have been done in two separate outages

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[65] Reply Argument page 106.
[66] Reply Argument page 111.

on Unit 2 while it is out of service for refurbishment. OPG stated that the historic underspend was a result of material spending shifts, and explained that underspend typically occurs when outages are shifted from one year to the next, and that resource constraints can sometimes lead to changes in outage work scope.

The OEB accepts OPG's arguments and will approve the outage OM&A budgets as filed (subject to the OEB's other findings on items such as compensation and stretch factor). The OEB encourages OPG to continue to look for efficiencies in its outage related activities.

Project OM&A covers temporary, unique endeavours undertaken outside the routine base activities of the normal work program. OPG proposes to spend about $100 million per year on project OM&A.

With the exception of PEO, there were no specific concerns raised regarding project OM&A. The OEB approves the project OM&A test period expenditures as filed (subject to the OEB's other findings on items such as compensation and stretch factor).

Fitness for Duty Program

OPG proposed to spend $41 million on a new "Fitness for Duty" program over the course of the test period. Fitness for Duty is a random drug and alcohol testing program for employees in nuclear facilities that would be a licence requirement of the CNSC. Although the CNSC had not yet imposed this program before the close of record in this proceeding, OPG is generally aware of the details and has attempted to budget accordingly. It is not known for certain when the program will be implemented.

The OEB will not approve the $41 million expenditure for the test period. Although the OEB appreciates that OPG has to do its best to budget and plan for events that it does not have control over (such as requirements imposed by regulators), both the quantum and the timing of the costs are sufficiently uncertain that the OEB is not prepared to include them in payment amounts at this time.

All parties who made submissions on this point, including OPG, agreed that a deferral account should be established. The OEB will allow OPG to establish the Fitness for Duty Deferral Account to track the costs (if any) of implementing the Fitness for Duty program for review and disposition at a later date.

5.7 Pickering Extended Operations

Background

In 2010, the end of life for Pickering Units 1 and 4 (formerly Pickering A) was planned for 2021 and the end of life for Units 5 to 8 (formerly Pickering B) ranged from 2014 to 2016. OPG undertook the Pickering Continued Operations project (PCO) to extend the life of Pickering Units 5 to 8 to 2020. Increasing the 210,000 Effective Full Power Hours (EFPH) operational life of the Units 5 to 8 fuel channels was the major part of PCO. The work started in 2010 and was completed in 2015[67] at a cost of $192 million.[68] The OEB's approval for costs related to PCO spanned the two previous cost of service proceedings. The current fuel channel life is 247,000 EFPH and the current end of life for all Pickering units is December 31, 2020.[69]

OPG plans to extend the life of the units at Pickering again. OPG is proposing to extend the operation of Pickering beyond the current end of life of 2020 such that all six units operate until 2022, at which point two units would be shut down and the remaining four units would operate until 2024. The project to extend operation of Pickering beyond 2020 is referred to as the Pickering Extended Operations project (PEO). OPG estimates that an additional 62 TWh would be generated and the value to the Ontario electricity system ranges from $500 million to $600 million, while the IESO estimates that the net benefit is $300 million (study as updated in October/November 2015) to $500 million (original study March 2015).

Incremental Costs of PEO

A PEO Business Case Summary (November 2015) was filed in this proceeding. It provided estimates for the three categories of incremental costs related to PEO.[70] The work to enable PEO (Enabling Costs) including fuel channel work to determine fuel channel fitness for service beyond 2020, is proposed to be completed in the period 2016 to 2020. OPG also proposes costs for restoration of normal operations (Restoration Costs). These OM&A costs were previously expected to cease with a 2020 Pickering end of life. Normal operating costs for the period 2021 to 2024 ($4,220 million) would also be considered incremental; the table below only lists the normal operating

[67] Exh F2-3-1 page 3.
[68] Exh F2-1-1, EB-2013-0321 Decision page 49.
[69] While Pickering Units 1 and 4 can operate beyond 2020, operation of Pickering Units 1 and 4 is linked to operation of Pickering Units 5 to 8 due to inter-dependent systems at the Pickering site. The current end of life, December 31, 2020, for all Pickering units for depreciation and amortization purposes was approved by the OEB in EB-2015-0374.
[70] Exh F2-2-3 Attachment 2 page 6.

costs for 2021, the last year covered by this application. The following table summarizes the Enabling Costs,[71] Restoration Costs and incremental operating costs for which approval is being sought in this application. The costs shown in the table are a portion of the overall nuclear OM&A costs addressed in section 5.6 of this Decision.

Table 20: Incremental Costs of PEO

	($million)	2016	2017	2018	2019	2020	Total 2016-2020	2021
1	Enabling Cost							
2	Base OM&A	11.0	1.0				12.0	
3	Outage OM&A		22.1	37.3	88.7	85.5	233.6	
4	Project OM&A	4.0	2.5	18.0	18.4	18.7	61.6	
5	**Total Enabling**	**15.0**	**25.6**	**55.3**	**107.1**	**104.2**	**307.2**	
6	Restoration Cost							
7	Base OM&A		7.9	13.5	28.4	61.6	111.4	765.5
8	Outage OM&A					47.2	47.2	244.2
9	Project OM&A		4.5	0.1	2.8	14.6	22.0	46.5
10	Project Capital			15.5	17.6	13.1	46.2	23.1
11	Corporate Support		2.6	3.0	7.1	10.7	23.4	315.2
12	**Total Restoration**		**15.0**	**32.1**	**55.9**	**147.2**	**250.2**	**1,394.5**
13	**TOTAL**	**15.0**	**40.6**	**87.4**	**163.0**	**251.4**	**557.4**	**1,394.5**

Source: Exh L-6.5-Staff-118

Note: 2021 costs are incremental operating costs, including the vacuum building outage

Status of Approvals and Reviews

A January 11, 2016 news release from the Ministry of Energy states:

> The Province has also approved OPG's plan to pursue continued operation of the Pickering Generating Station beyond 2020 up to 2024, which would protect 4,500 jobs across the Durham region, avoid 8 million tonnes of greenhouse gas emissions, and save Ontario electricity consumers up to $600 million. OPG will engage with the Canadian Nuclear Safety Commission and the Ontario Energy Board to seek approvals required for the continued operation of Pickering Generating Station.

OPG's 2016-2018 and 2017-2019 business plans reflect PEO. Both plans have been approved by the Ministry of Energy.

The current Pickering power reactor licence was issued by the CNSC on September 1, 2013 and expires on August 31, 2018. In June 2014, the CNSC removed a regulatory

[71] $292 million of the $307 million Enabling Cost is forecast to be spent during the IR term: AIC page 88.

hold point prohibiting operation of Pickering beyond 210,000 EFPH. In its decision, the CNSC allowed OPG to continue operating Pickering up to 247,000 EFPH.[72]

At the request of the Ministry of Energy, the IESO prepared an assessment of PEO which was filed with the application. The IESO determined that the overall system economic value of PEO is positive as it reduces the need to operate or build more expensive gas-fired generation, increases export revenues and reduces carbon emissions. The IESO also concluded that PEO had other system planning benefits in addition to its economic value.

The OEB considered a motion by Environmental Defence that among other things sought an update to the IESO's cost-benefit analysis to reflect changes in circumstances such as the change in natural gas prices. For the reasons set out in the motion decision, the OEB decided that it would not require the IESO to update the cost-benefit analysis.[73] The motion decision, however, stated that the OEB was “open to considering arguments on appropriate cost containment measures to ensure efficient operation of Pickering.”

Submissions of Parties

The Society and the PWU support PEO. Other parties submitted that the IESO analysis supporting PEO was weak and some of these parties submitted that the analysis should be updated before recovery of any PEO costs is approved. In support of their arguments, parties cited the changes since the cost-benefit analysis was completed including: lower cost of electricity imports, lower natural gas prices, introduction of the cap and trade program and lower load forecast. Environmental Defence also submitted that the cost to operate Pickering from 2021 to 2024 is $778 million higher than the costs OPG provided to the IESO. Furthermore, parties referred to Pickering’s weak cost performance and reliability performance.

Both Environmental Defence and GEC argued that operating Pickering beyond 2018 was not cost effective, and completion of the Clarington Transformer Station in 2018 will address certain operating limitations in the eastern Greater Toronto Area. SEC does not support PEO or operation beyond 2020, but acknowledges that not approving PEO will lead to an increase in payment amounts due to severance costs and less time to amortize nuclear liabilities, among other things.

In light of the fact that PEO had not been approved on a final basis via the Long-Term Energy Plan (LTEP) and the fact that the CNSC licence expires in 2018, OEB staff

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[72] Exh F2-2-3 page 3.
[73] Decision and Order on Motion Filed by Environmental Defence, EB-2016-0152, February 16, 2017.

proposed that the OEB approve the 2017 and 2018 Enabling Costs only, with any costs beyond 2019 added to the CRVA. (The LTEP was issued in October 2017, after the record in this proceeding had closed, and it endorsed the continued operation of Pickering to 2024, while noting that final government approval would still be required after the OEB and the CNSC reviewed the project.) LPMA proposed interim approval of the enabling costs. OEB staff also proposed that restoration costs be recorded in a new deferral account, to be disposed after the CNSC's licensing decision.

OPG argued that the IESO cost-benefit analysis was not outdated when filed and that it would not be appropriate to update only some variables when there are many inter-relationships among the various factors considered.[74] OPG noted that several parties proposed to defer or disallow costs but that these proposals did not align with proposals in other areas of the parties' submissions. OPG also submitted that there is a strong likelihood of approval by the CNSC given progress on technical assessments, and of approval of PEO in the 2017 LTEP.[75]

Findings

The OEB's findings in this section relate to the incremental costs of PEO as set out in Table 20 above. The Ministry of Energy has "approved OPG's plan to pursue continued operation of the Pickering Generating Station beyond 2020 up to 2024".[76] The OEB approves the test period enabling costs (Line 5 in Table 20) that will fund technical assessments to determine fitness for service of Pickering units beyond 2020, i.e. OPG's plan to pursue PEO.

While OPG's application is underpinned by PEO and operation of all Pickering units in 2021, the technical assessments are not yet complete and could indicate that some or all units at Pickering may not be fit for service beyond 2020. In addition, the Minister of Energy as the system planner may determine at a later date that some or all the units at Pickering will not be required beyond 2020. Generation planning, including the economics related to generation planning, is not within the scope of this payment amounts proceeding. Should the outcome of the technical assessments or system planning decisions significantly impact operation of Pickering in 2021, OPG shall return to the OEB to seek direction.

The proposed PEO restoration costs and 2021 operating costs are reviewed in section 5.6 – Nuclear OM&A. The OEB will disallow some of these nuclear OM&A costs on the

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[74] Reply Argument page 134.
[75] Reply Argument page 137.
[76] Ministry of Energy News Release, January 11, 2016.

basis of a review of historical costs and Pickering's fourth quartile nuclear benchmarking performance. The OEB's finding on restoration costs and 2021 operating costs is not an endorsement of PEO. The reasons for the OEB's findings are discussed in the sections that follow.

Scope of Review

There is no shareholder directive to OPG regarding PEO, and unlike DRP, there is no specific reference to the need for PEO in O. Reg. 53/05. When the record closed in this proceeding, the LTEP in place was the 2013 LTEP, and it did not refer to operation of Pickering beyond 2020. On October 26, 2017, the 2017 LTEP was issued. It states:

> OPG is working on plans to continue to operate the Pickering Nuclear Generating Station until 2024. The continued operation of Pickering will ensure Ontario has a reliable source of emission-free baseload electricity to replace the power that will not be available during the Darlington and initial Bruce refurbishments. The continued operation of Pickering would also reduce the use of natural gas to generate electricity, saving up to $600 million for electricity consumers and reducing GHG emissions by at least eight million tonnes.
>
> The Province announced in January 2016 that it had approved OPG's plan to ask the OEB and the Canadian Nuclear Safety Commission (CNSC) to approve the continued operation of Pickering until 2024. The OEB will ensure that the costs of OPG's plan for continued Pickering operation are prudent, while the CNSC will ensure that Pickering operates safely during this period. OPG will still need to get final approval from the government to proceed with the continued operation of Pickering after these regulatory reviews are completed.[77]

In this proceeding, OPG has applied for, and the OEB is considering, a five-year test period from 2017 to 2021. Pending the results of the technical assessments of fitness for service, and the final system planning and government determinations, the OEB could be required to consider costs for the operation of Pickering beyond the current test period, which ends in 2021, in a future proceeding.

Section 78.1 of the Act empowers the OEB to set just and reasonable payment amounts for OPG's regulated generation facilities. The recent amendments to O. Reg. 53/05 require the OEB to determine revenue requirement for the nuclear facilities for each year on a five-year basis, and to smooth weighted average payment amounts beginning on January 1, 2017 and ending when DRP concludes. The proposed revenue requirement for the nuclear facilities includes the costs set out in Table 20.

In assessing OPG's proposed incremental costs for PEO during the 2017 to 2021 test period, the OEB has considered whether the costs are reasonable. Several parties have

[77] Ontario's Long-Term Energy Plan – 2017, Delivering Fairness and Choice, October 26, 2017.

submitted that the OEB's consideration of incremental costs for PEO should also consider the need for the operation of Pickering beyond 2020.[78] In its submission on the Environmental Defence motion, OEB staff stated:

> The onus rests with OPG to show that the costs it seeks to recover through OEB approved payment amounts are reasonable. The OEB's enquiry into the reasonableness of the proposed payment amounts could extend to asking whether a particular project is necessary at all. If the OEB determines that a proposed project provides poor value for ratepayers, then it should not approve the costs associated with that project.[79]

SEC filed the following submission on this matter:

> There are no legislative or regulatory constraints on the Board's role in determining the appropriateness of including, in payment amounts, the costs for extending Pickering. As is the case for all other investments, in making its determination whether costs are reasonable, the Board must determine if there is a need for the underlying asset or activity that warrants the expenditure.[80]

PWU did not agree, submitting that section 78.1(1) of the Act entitles OPG to receive payments from the IESO with respect to the output that is generated by prescribed facilities. The sole role of the OEB is to determine the amount of that payment.

As noted in OPG's reply argument, the OEB has stated in every previous cost based proceeding that its role with respect to Pickering is to set just and reasonable payment amounts.[81] Section 25.29 of the *Electricity Act, 1998* establishes that the Minister of Energy (with the approval of the Lieutenant Governor in Council) is responsible for system planning, and in that role many factors are considered and evaluated as noted in the LTEP excerpt regarding PEO above, including emissions, amount of baseload generation and replacement power. The IESO witness testified that determining the value of Pickering operation beyond 2020 is a complex matter requiring assessment of many factors that impact the provincial grid. Consistent with previous proceedings and the OEB's findings on the Environmental Defence motion,[82] the OEB finds that generation planning, including the economics related to generation planning, is not within the scope of this payment amounts proceeding.

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[78] Some parties have questioned the need beyond 2018.
[79] OEB Staff Submission on Environmental Defence Motion, December 9, 2016.
[80] SEC Submission page 76
[81] Reply Argument page 131.
[82] Decision and Order on Motion Filed by Environmental Defence, February 16, 2017, page 5.

A significant amount of the examination relating to PEO was directed to the IESO's Assessment of Pickering Life Extension Options.[83] As noted above, the IESO's assessment was prepared in 2015 at the request of the Ministry of Energy. Several parties, Environmental Defence and GEC in particular, challenged whether the IESO's assessment was sufficiently robust and whether all considerations and sensitivities had been sufficiently assessed, e.g. decreasing provincial demand, lower natural gas prices, lower generation replacement costs. On the basis of these concerns and based on their analysis, Environmental Defence and GEC argued that it is uneconomical to operate Pickering beyond 2018. Environmental Defence submitted that the operation of Pickering from 2018 to 2020 is a net cost to ratepayers and that this net cost should be included in assessment of cost effectiveness of operation beyond 2020.

Some parties argued that the IESO assessment should be updated before the OEB approved PEO costs. OEB staff noted in cross-examination that the CNSC may issue a partial approval which extends the permitted EFPH by a lesser amount than OPG is requesting. The IESO witness agreed that further analysis of benefits would be required.[84] However, for the purposes of this proceeding, and as determined in the decision on Environmental Defence's motion, the OEB finds that an updated IESO assessment would be of limited value.

The OEB finds that the examination of the IESO's assessment in this proceeding was informative. The IESO witness testified that the next 10 to 15 years are a source of very significant change in Ontario's power system including the future prospects of generation contracts once they reach their commercial term.[85] The witness stated that:

> A lot of that is distilled into the early to mid and late 2020s, when we have the maximum refurbishments going on in our fleet. And for that reason, aside from the potential for economic benefit, aside from that potential which we acknowledge here can be plus or negative, right? We don't know. But aside from all that, we think that Pickering provides some important potential coverage during that period of transition.[86]

This testimony is consistent with the OEB's view stated above that a large number of factors need to be assessed before the system planner can issue a final approval on Pickering operation beyond 2020. While some of the factors were reviewed in this proceeding, many underlying system planning considerations were not.

[83] Exh F2-2-3 Attachment 1.
[84] Tr Vol 12 page 115-116.
[85] Tr Vol 8 pages 91-92.
[86] Tr Vol 8 page 92.

Pickering Operation in 2018

Environmental Defence and GEC submitted that there may be no need for Pickering beyond 2018 for economic reasons and the future completion of the Clarington Transformer Station. The submissions of Environmental Defence and GEC point to the 2013 LTEP which referred to a potential early shutdown of Pickering:

> The Pickering Generating Station is expected to be in service until 2020. An earlier shutdown of the Pickering units may be possible depending on projected demand going forward, the progress of the fleet refurbishment program, and the timely completion of the Clarington Transformer Station

The 2017 LTEP has since been released and it refers to an eventual retirement of Pickering:

> To meet the needs of the growing eastern GTA and prepare for the eventual retirement of Pickering Nuclear Generating Station, Hydro One is building the Clarington Transformer Station in the Municipality of Clarington. Hydro One expects to bring the station into service in 2018.

The OEB also notes that OPG's 2017-2019 business plan, including operation at Pickering, has been approved by the Minister of Energy.[87] The future of Pickering as it relates to the Clarington Transformer Station is a matter that will be considered by the system planner, not the OEB. However, should completion of the transformer station trigger a shutdown of Pickering in the test period, OPG shall return to the OEB to seek direction.

The current Pickering five-year power reactor licence expires on August 31, 2018. OEB staff submitted that the CNSC determination on the Pickering power reactor operating licence in 2018 was a risk. In the application OPG stated that it expects to request a 10-year licence renewal, which will take the Pickering units through both the end of commercial operations and the safe storage period. OPG anticipates that the CNSC decision addressing operation beyond 2020 will occur as part of the Pickering licence renewal.

[87] Reply Argument, Appendix A.

The current CNSC licence allows OPG to operate Pickering up to 247,000 EFPH. OPG's witnesses summarized their communications with the CNSC in cross-examination:

> We've already provided a high confidence statement and we've been working closely with the regulator over the last couple of years with respect to operating the units to 261,000 hours, so we've been working in increments, in terms of demonstrating that we can achieve this end of life, and if you look at where we are in terms of 261,000 hours, that would essentially take five units out to 2022 and a couple of them beyond 2022 already.[88]

Should a CNSC licensing matter materially affect Pickering operation in the test period, OPG will be expected to notify the OEB.

Enabling Costs

OPG has forecast PEO enabling costs of $307.2 million of which $292.2 million are test period costs (line 5 of Table 20). Some of the enabling costs must be incurred in 2017 and 2018 in order for OPG to be in a position to obtain the licence renewal it seeks from the CNSC in 2018. This includes costs for the Periodic Safety Review, Fuel Channel Life Extension project and other asset condition assessments. All the enabling costs are CRVA eligible.

In January 2016, the Ministry of Energy "approved OPG's plan to pursue continued operation of the Pickering Generating Station beyond 2020 up to 2024". In cross-examination, the IESO witness supported "the continued exploration of this Pickering extension concept".[89] No parties challenged the specific activities or the quantum of the enabling costs.

The OEB approves the test period enabling costs that will fund technical assessments to determine fitness for service of Pickering units beyond 2020.

Restoration Costs and Operating Costs

OPG has forecast PEO restoration costs of $250.2 million in the test period and incremental operating costs related to Pickering of $1,394.5 million in 2021 (line 12 of Table 20).

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[88] Tr Vol 15 page 146.
[89] Tr Vol 8 page 87.

Regarding restoration costs, OPG's evidence is that the shutdown in 2020, as previously anticipated, would have caused the cost of ongoing operations to decline starting in 2017.[90] OPG states that the restoration costs proposed are necessary to restore ongoing operating and maintenance programs to normal levels for the 2017 to 2020 period to enable PEO to go forward. For example, OPG states that outage requirements that were set to decline will now need to be reinstated. As well, both OM&A and capital projects will need to be restored to the levels required to continue to operate safely and reliably for two to four additional years and to improve plant reliability during that time. Restoration costs include labour costs, "non-portfolio" projects to address life cycle aging of equipment and regulatory requirements resulting from PEO and costs of the two year planned outage schedule for routine inspection and maintenance.[91]

The submissions on these test period restoration costs and operating costs in 2021 range from zero (SEC and GEC) to approval of all costs (PWU and Society). The PWU submission states that the only potential basis to disallow any part of the proposed costs is Pickering's relative cost performance in benchmarking, although the PWU has reservations regarding the Pickering benchmarking results.

In considering whether the proposed Pickering restoration costs and operating costs in 2021 are reasonable, the OEB has reviewed historical costs and Pickering's performance against other nuclear operators. Some parties have argued that the OEB should consider cost effectiveness from a system planning perspective including comparison with other generation options. As noted above, the OEB finds that this is not within scope.

The OEB is making findings on the prudent costs of restoration in the test period and operation of Pickering in 2021, to allow for the operation of Pickering from 2017 to 2021 as is currently expected by the system planner.

The base, project and outage OM&A disallowances are reviewed in section 5.6 – Nuclear OM&A. Project capital is reviewed in section 5.2, and corporate support costs are reviewed in section 5.8.

Depreciation

Except in calculating depreciation (including the depreciation on asset retirement costs), OPG has prepared its application on the basis that PEO will go forward as currently planned. OPG is proposing that any adjustments to depreciation arising from the

[90] Exh F2-2-3 pages 6 and 7.
[91] Exh F2-3-1 page 2.

extension of life of the assets via PEO will be captured in a deferral account. No party objected to this approach. The OEB approves this approach, noting that it is consistent with the approach previously approved by the OEB.

Future Considerations

As explained below in section 9 of this Decision, the OEB has not approved the mid-term review for production forecast proposed by OPG. However, OPG shall return to the OEB to seek direction if the outcome of the technical assessments or system planning decisions significantly impact operation of Pickering in 2021 and if a CNSC licensing matter materially affects Pickering operation in the test period.

5.8 Corporate and Centrally Held Costs

5.8.1 Corporate Costs

OPG corporate business functions provide support to the nuclear business, the regulated hydroelectric business and the unregulated business. The corporate support costs have been allocated using the methodology that was accepted by the OEB in previous proceedings. The historical and test period corporate support costs allocated to the nuclear business are summarized in the following table:

Table 21: Nuclear Corporate Costs

	$million	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
1	Business and Admin Service												
2	IT NHSS	62.5	61.2	60.5	55.9	54.6	52.7	46.8	45.3	43.7	43.7	42.1	40.8
3	IT Support Cost	27.8	24.6	22.6	35.9	36.6	37.3	41.8	43.7	42.6	42.3	42.7	43.2
4	Total IT Costs	90.3	85.8	83.1	91.8	91.2	90.0	88.6	89.0	86.3	86.0	84.8	84.0
5	Supply Chain	3.4	2.6	48.4	48.6	42.5	41.1	47.6	47.3	46.7	47.8	49.2	50.3
6	Real Estate	31.7	31.7	96.2	88.4	83.3	82.5	89.9	94.5	92.8	95.0	95.5	98.7
7	OM&A Project Costs	6.8	8.1	9.5	17.9	10.2	17.4	18.9	15.3	13.3	12.2	12.8	13.1
8	Total Business and Admin Service	132.2	128.2	237.2	246.7	227.2	231.0	245.0	246.1	239.1	241.0	242.3	246.1
9	Finance	33.3	38.0	46.2	46.3	44.4	35.6	40.2	41.5	39.4	39.0	38.8	39.9
10	People and Culture	33.9	38.0	90.0	91.6	98.2	95.8	92.4	96.2	95.3	97.8	98.5	100.5
11	Commercial Ops and Environment	16.7	16.4	12.7	14.7	19.5	16.8	20.4	20.2	18.9	19.9	19.6	21.8
12	Corporate Centre	10.4	12.5	22.3	29.2	26.9	39.6	44.3	44.9	44.5	45.0	45.8	45.8
13	**TOTAL (lines 8-12)**	**226.5**	**233.1**	**408.4**	**428.5**	**416.2**	**418.8**	**442.3**	**448.9**	**437.2**	**442.7**	**445.0**	**454.1**
14	2016 Actual							426.2					

Source: Exh F3-1-1 Table 3 and 7 (EB-2013-0321),Exh F3-1-1 Table 3 and 7, Undertaking J14.2

OPG's Business Transformation initiative restructured the company around a centre led model. A large number of staff from operations and project groups were transferred in 2012 to support groups such as procurement, records, facility management, financial reporting and training. The application states that OPG has taken advantage of economies of scale by consolidating staff that perform similar work and streamlining processes. OPG has proposed that the nuclear Custom IR stretch factor apply to base OM&A and allocated corporate OM&A.

The OEB directed OPG in the EB-2013-0321 decision to undertake an independent benchmarking study of corporate support functions and costs given the significant changes resulting from Business Transformation. OPG filed a benchmarking study completed by the Hackett Group.[92] Hackett reviewed the corporate support function for all OPG regulated operations. Corporate costs assigned and allocated were included in the benchmarking. The corporate support costs for 2010 and 2014 were compared to a peer group of companies in multiple industries that Hackett determined to have similar size and business complexity to OPG. The peer group consisted of 19 companies, including six nuclear operators (Ameren Corp, Areva, Arizona Public Service Company, Constellation Energy Resources, Florida Power and Light, and Public Service Energy Group).

Hackett found that while OPG's benchmark performance improved between 2010 and 2014, OPG still lagged in Executive and Corporate Services (ECS) functions. The results of the Hackett benchmarking for Information Technology, Human Resources, Finance and ECS are summarized in the following table. The data as well as the quartile results are summarized:

Table 22: OPG Corporate Cost Benchmarking Results

Corporate Function	OPG 2010	OPG 2014	Peer Median	OPG Improvement
IT Cost per End User	$12,015 (Q1)	$9, 541 (Q1)	$14,995	21%
HR Cost per Employee	$3,400 (Q3)	$3,375 (Q3)	$3,350	1%
Finance Cost (% of Revenue)	1.02% (Q4)	0.75% (Q3)	0.66%	26%
ECS Cost (% of Revenue)	3.39% (Q4)	2.75% (Q4)	1.07%	19%

Source: Exh F3-1-1 Figure 1, Exh L-6.7-Staff-169 Attachment 1

In its Argument in Chief, OPG stated that the Hackett benchmarking demonstrates that there have been significant improvements in controlling corporate support costs. OPG recognizes that ECS costs did not benchmark well, but there are factors requiring additional costs given the scope of the nuclear operations.

92 Exh F3-1-1 Attachment 1.

Several parties proposed test period nuclear allocated corporate support cost reductions ranging from $40 million to $100 million on the basis of benchmarking performance and historical under-spending.

Findings

No submissions were filed regarding the allocation of corporate costs to the nuclear business. The OEB accepts the methodology as applied in the application.

In order to allow for “apples to apples” comparisons, the Hackett study compared costs by function; not by how they are categorized or organized at OPG or the peer comparators. This is an appropriate way to benchmark, but does create challenges as OPG has not provided any kind of cross-reference between the benchmarked categories and its organizational structure for corporate costs as set out in the table above.

During the hearing OPG was asked to provide the revenue requirement impact over the five years for OPG to achieve the 2014 median for the Finance and the ECS benchmarks. OPG calculated that the revenue requirement impact for ECS is a reduction of $307 million and the impact for Finance is a reduction of $19 million. OPG also pointed out that HR and IT costs would be below median by $27 million and $395 million respectively, which should be used to offset the higher ECS and Finance costs.[93]

The OEB does not agree that these different categories of costs are interchangeable. The OEB expects to see good performance and efficiencies in all areas of OPG business. These functions are benchmarked separately – there is no overall benchmark for corporate costs. They are also benchmarked on different bases – ECS and Finance as a percentage of company revenue, as they reflect overall management of the company, IT by cost per end user, and HR by employee.

Some parties questioned the basis on which the number of IT end users was determined as it includes many contractors’ employees on site including those working on the DRP, even if their use is limited to having access to the system for the purpose of looking at plans and drawings while on site. The OEB agrees there is some merit to this argument as the annual IT cost shown on Table 21 trends downward slightly (from $91.2 million in 2014 to $84 million in 2021) while the number of Total Nuclear FTEs (Table 23 nuclear staffing levels section) also trends downward from 8,431 in 2014 to 8,293 in 2021. The only way the cost per end user could drop by from $9,541 in 2014 to $7,652 in 2021 is if there are many more end users than those accounted for in the

[93] Undertaking J20.3.

FTEs. The OEB is not persuaded that the improvement in this metric is due to efficiencies by OPG so that it can offset poor benchmarking in other areas.

While ECS has shown some improvement, the cost of ECS as a percentage of revenue in 2014 was more than twice as much as the median. OPG was the worst performer of the peer group for ECS in both 2010 and 2014. As noted above, if ECS was at the 2014 median in the test period, the nuclear revenue requirement would be $307 million lower. OPG recognizes that its ECS costs are higher than comparators, but attributes high costs to the need to ensure safety, environmental stewardship and robust risk management for its nuclear operations.[94]

While Hackett included a broad range of functions in ECS (administrative services, transportation services, real estate and facilities management, government affairs, legal/regulatory affairs, quality management, risk management and environment, health and safety, corporate communications, planning and strategy, and executive office and procurement) a number of functions were specifically excluded from their analysis. These were security management, travel services, legal (M&A), nuclear specific costs (e.g. nuclear facilities costs), anything related to DRP, staff training, nuclear specific finance (e.g. insurance) and electricity sales and trading.[95] The OEB concludes that many of the functions OPG suggests are the cause of its ECS costs being higher than comparators are functions that were excluded from the benchmarking so they are not a justification for OPG's higher costs.

The OEB also agrees with CME's submission that the comparators in the Hackett benchmarking study, including six nuclear operators and 11 organizations with unions, faced similar operational needs. While CME submitted that a $100 million reduction related to ECS costs in the test period would approximate third quartile performance, the OEB expects OPG's performance to be closer to the median. CME also proposed an additional $19 million reduction related to the finance function.

OEB staff reviewed OPG's allocated corporate cost for the historical and test period as presented in Table 21 and in relation to the functions benchmarked by Hackett, although the analysis was limited. OEB staff submitted that some of the trends were not supported and proposed a 1% per year increase on 2014 actuals, reducing the test period revenue requirement by $40.6 million. OPG argued that the OEB staff analysis did not account for all the drivers and changes noted in the evidence and that applying a formula to an historical year is inconsistent with Custom IR.

[94] Reply Argument page 163.
[95] Exh F3-1-1 Attachment 1 pages 6-7.

SEC reviewed variances of actual corporate costs and OEB approved amounts or budgeted amounts. SEC submitted that at 2.5% reduction per year, i.e. the 2014-2016 variance, should be applied, resulting in a $55.7 million test period reduction. LPMA's submission included a similar analysis resulting in a $60.8 million reduction. OPG argued that it has provided reasons, e.g. the delay in the sale of its office building at 700 University Avenue in Toronto, for the historical period variances.

The OEB agrees that there are many factors affecting the allocated corporate costs in the test period. While there is some merit to consideration of the historical costs and variances, the OEB finds that the benchmarking results of the ECS function outweigh all other considerations. The OEB finds that OPG's ECS costs are much too high compared to the comparators who Hackett characterizes as "a custom group of companies in multiple industries that have similar size and business complexity to OPG."[96] Hackett also observed that, "OPG ECS has opportunities to peer especially in the areas of Risk Management and [Environment, Health & Safety], Procurement, and Real Estate." The OEB agrees and has used this as one of the factors underpinning a significant reduction to the nuclear OM&A related revenue requirement. Between ECS and Finance, OPG is more than $300 million above the median for the five-year test period.

The nuclear OM&A related revenue requirement will be reduced by $45 million per year on account of the corporate allocated costs.

As noted in section 8.2, the Custom IR stretch factor will be applied to the allocated corporate costs.

The OEB expects OPG to file an updated benchmarking study of corporate costs with its next cost based application. The OEB observes that OPG provided corporate support cost for Pickering in Table 20 of section 5.7. In addition to its usual evidence on corporate support costs, OPG shall file nuclear corporate support information by station for the historical and test period in the next cost based application.

5.8.2 Centrally Held Costs

Centrally held costs are allocated to the nuclear business, the regulated hydroelectric business and the unregulated business. The allocation methodology applied is the same as that applied in previous payment amount applications.

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[96] Exh F3-1-1 Attachment 1 page 6.

The centrally held costs include pension and OPEB related costs (costs other than current service costs), insurance, performance incentives and IESO non-energy charges. The allocation of centrally held costs for the nuclear business is set out in Table 3 of Exh F4-1-1.

The nuclear business centrally held costs also include a negative adjustment to the test period costs to reflect the forecast differential between accrual costs and cash amounts for pension and OPEBs.

No parties opposed OPG's application with respect to centrally held costs.

Findings

The OEB agrees with the proposed allocation of centrally held costs, which is not disputed.

5.9 Compensation

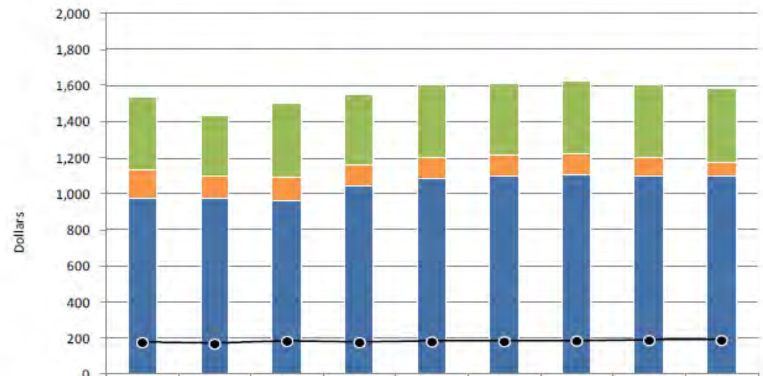
Background

This section reviews the amounts that OPG pays its nuclear (including nuclear allocated) employees. OPG's total compensation package includes wages (including wages for overtime), pensions, and other benefits. There is no "line item" for compensation in OPG's application; rather, compensation costs are incorporated into other areas such as OM&A costs. Compensation costs are a function of both the number of employees and the amount of total compensation paid to those employees.

As of the end of 2015, almost 80% of OPG's regular employees worked directly in, or in support of, OPG's nuclear facilities.[97] OPG's total compensation costs represent a very significant expense for the company: on average approximately 40% of its requested revenue requirement; in 2017 it approaches 50% of the requested revenue requirement.[98] The following chart provides a high level annual breakdown of OPG's nuclear compensation costs:

[97] OPG AIC, p. 96.
[98] OPG AIC, pp. 94-95.

Figure 3 - Compensation Costs for Nuclear Facilities



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

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

OPG's compensation costs are relatively flat over the test period. The total compensation paid is actually forecast to be slightly lower in 2021 than 2017, whereas the total compensation per employee is forecast to be slightly higher (the total is lower because OPG expects to have fewer employees).

OPG's nuclear workforce is approximately 90% unionized. Unionized workers are represented by either the Society or the PWU. Wages, pensions and benefits all have to be collectively bargained for OPG's unionized employees, and most parties agree that this places limitations on OPG's ability to reduce its compensation costs.

OPG's total compensation levels have been a contentious issue in previous payment amounts proceedings before the OEB. The OEB has made disallowances related to excessive compensation levels in all three previous full payment amounts proceedings: $35 million in the first payments case,[99] $145 million over two years in EB-2010-0008, and $200 million over two years in EB-2013-0321.[100]

With the exception of the two union intervenors, OEB staff and most intervenors argued for disallowances for excessive compensation in the nuclear business in this

[99] The disallowances in this case were for poor performance at the Pickering A facility generally, and were not tied directly to excessive compensation.
[100] The disallowance is this case was for both the regulated hydroelectric and nuclear businesses.

proceeding. The disallowance sought ranged from about $50 million per year to about $100 million per year. OPG and the union intervenors argued that the compensation expenses should be approved as filed.

Benchmarking

OPG commissioned benchmarking reports on both total direct compensation and pensions and benefits. It also conducted extensive benchmarking on its overall performance as a nuclear operator which, although not compensation benchmarking *per se*, is still relevant to this analysis.

Total Direct Compensation

OPG retained Willis Towers Watson (WTW) to benchmark both its total direct compensation, which includes average salary, target bonus and other applicable allowances. It does not include overtime, the share performance plan, or the lump sum payment that was paid to unionized employees in exchange for certain changes to the pension plan.

WTW also benchmarked OPG’s pensions and other benefits, which are reviewed in the next section.

For total direct compensation, WTW measured the PWU, the Society, and Management in three categories: utility, nuclear authorized, and general industry. OPG job functions were measured against comparable positions in comparable organizations. Overall, the WTW study concluded that OPG’s total direct compensation was essentially at benchmark. This is an improvement over the benchmarking results in previous proceedings, which had showed OPG to be above benchmark to varying degrees.

Several parties critiqued portions of the WTW study. Significant elements of OPG’s compensation package were excluded from the study: overtime (which averages more than $100 million per year over the test period) and the share performance plan and lump sum payment (which cost a combined $92 million over the test period). There was also concern regarding the low number of positions that were benchmarked in some areas, and OPG’s use of the 75th percentile as its benchmark standard for the nuclear authorized segment. Parties also observed that, although the overall results show OPG to be close to benchmark, in some areas (particularly general industry) OPG is well above the benchmark.

Pensions and Benefits

OPG offers its employees several pension and benefits plans. For retired employees, there are the registered pension plan, other post-employment benefits (OPEB), and a supplemental pension plan. Current employees also have a comprehensive benefits package. Pensions and benefits form a significant component of OPG's total compensation costs, and indeed of its total revenue requirement. Over the test period pensions and OPEBs for the nuclear business are forecast to cost an average of $329 million per year on a cash basis, and $355 million on an accrual basis.[101] These figures do not include the costs of benefits for current employees; as shown in the chart above, the total costs including benefits for current employees average over $400 million per year over the test period on an accrual basis.

The sustainability of OPG's pensions and benefits has improved in recent years. This is largely the result of increased pension contributions that were negotiated with the Society and the PWU in the most recent round of collective bargaining. Despite this, no party disputes that the cost of OPG's pensions and benefits remains above benchmark.

OPG filed several benchmarking reports related to its pensions and benefits. The WTW report included a section on pensions and benefits (which included both OPEBs and benefits for current employees). WTW concluded that OPG's pensions and benefits were 32% more generous than their comparators. OPG also filed a Benefit Index Report prepared by AON Hewitt. Although portions of the report are confidential, the conclusion was that overall OPG's benefits were between the second and third most generous amongst its comparators, and were 11% above market.[102]

OPG calculates an employer-employee contribution ratio for its registered pension plan. Both the Auditor General and the *Report on the Sustainability of Electricity Sector Pension Plans* (the Leech Report) have recommended that OPG's contribution ratio should be approximately 1:1, which is typical in the public service. According to OPG, its contribution in 2015 was approximately 3:1, and it is expected to be approximately 2:1 in 2017. (Further information on the expected ratio for the rest of the test period is confidential, but the information is available in the confidential exhibit, Exh L-6.6-Staff-157, Attachment 1, and is summarized on pages 111-112 of OEB staff's submission.)

Several parties argued that the methodology used by OPG to calculate the contribution ratio is misleading, and that the true ratio is much higher. Parties argued that OPG excluded significant employer expenses from its calculation, such as special payments and the cost of OPEBs. Depending on exactly what employer expenses are included in the calculation, the contribution ratio was calculated to be closer to 3:1 or 4:1 in 2018.[103]

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[101] OEB staff submission, Table 26, page 106.
[102] Exh L-6.6-Staff-157 Attachment 2 page 31.
[103] See, for example, OEB staff submission pages 110-111.

Nuclear Performance Benchmarking

In addition to the compensation specific benchmarking reports, OPG also filed benchmarking analysis on its overall performance as a nuclear operator. As detailed in section 5.4, OPG's overall results were poor. As noted in the section on nuclear OM&A overall nuclear benchmarking has been taken into account as one of the factors leading to a reduction on approved OM&A.

Staffing Levels

As previously noted, compensation is a function of both the number of staff and remuneration. The following table summarizes historic and test period staffing levels for the nuclear business. The data are listed for operations and DRP, as well as for employee group. The table includes 2016 budget and actual Full Time Equivalents (FTE).

Table 23: Nuclear Business Full Time Equivalents

Nuclear FTE	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2016 Actual	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Operations												
Regular	7,404.9	6,100.7	5,870.7	5,626.7	5,430.4	5,788.6	5,341.1	5,710.8	5,666.2	5,602.1	5,504.1	5,394.7
Non-Regular	583.7	436.0	496.9	578.1	670.0	666.7	843.8	614.4	646.6	632.2	526.8	420.4
Total Nuclear Operations	**7,988.6**	**6,536.7**	**6,367.6**	**6,204.8**	**6,100.4**	**6,455.3**	**6,184.9**	**6,325.2**	**6,312.8**	**6,234.3**	**6,030.9**	**5,815.1**
Corporate												
Nuclear Allocated	876.1	2,037.2	1,919.5	1,884.4	1,628.9	1,773.3	1,659.8	1,742.8	1,703.7	1,679.8	1,659.0	1,656.2
Total Operations&Corp	**8,864.7**	**8,573.9**	**8,287.1**	**8,089.2**	**7,729.3**	**8,228.6**	**7,844.7**	**8,068.0**	**8,016.5**	**7,914.1**	**7,689.9**	**7,471.3**
DRP												
Regular	208.1	210.9	282.0	307.2	329.7	427.6	422.6	587.2	599.9	620.5	589.5	597.8
Non-Regular	18.4	14.2	24.6	35.3	60.7	73.5	112.7	153.2	152.2	137.4	157.7	230.1
Total DRP	**226.5**	**225.1**	**306.6**	**342.5**	**390.4**	**501.1**	**535.3**	**740.4**	**752.1**	**757.9**	**747.2**	**827.9**
TOTAL NUCLEAR*	**9,091.2**	**8,799.0**	**8,593.7**	**8,431.7**	**8,119.7**	**8,729.7**	**8,380.0**	**8,808.4**	**8,768.6**	**8,672.0**	**8,437.1**	**8,299.2**
Management	950.7	952.1	960.8	929.1	890.3	926.9		958.5	950.2	945.7	933.6	920.6
Society	2,908.7	2,755.0	2,615.5	2,547.8	2,484.0	2,753.9		2,784.5	2,769.9	2,708.1	2,633.3	2,592.0
PWU	5,152.0	5,005.6	4,957.1	4,885.2	4,633.2	4,904.3		4,871.4	4,853.2	4,855.3	4,681.9	4,551.5
EPSCA	79.8	86.3	60.2	69.6	106.2	135.6		186.7	188.1	155.6	181.1	229.1
TOTAL NUCLEAR*	**9,091.2**	**8,799.0**	**8,593.7**	**8,431.8**	**8,113.7**	**8,720.7**		**8,801.2**	**8,761.4**	**8,664.7**	**8,429.9**	**8,293.2**

Source: Exh F2-1-1 Table 3, Exh F4-3-1 Appendix 2K, Exh F2-2-1 Table 2 - EB-2013-0321 and EB-2016-0152, Undertaking J13.3, J14.6

EPSCA - Electrical Power Systems Construction Association

*OPG proposed to address the difference of app. 7 FTE (2015 to 2021) by reducing revenue requirement by app. $1 million through the payment order process (L-6.6-Staff-139)

OPG's Business Transformation project restructured the company around a centre led model, reducing OPG regular headcount by nearly 2,700 positions between 2011 and 2015. The impact of Business Transformation is evident in the trend in total nuclear FTE and nuclear allocated corporate FTE in the period 2011 to 2015.

The OEB directed OPG to conduct an examination of nuclear staffing levels, after considering weak nuclear operations benchmark results in the EB-2010-0008 proceeding. OPG retained Goodnight Consulting Inc. (Goodnight), to benchmark OPG nuclear staffing, and the study was filed in the EB-2013-0321 proceeding. The results of that study, and the Goodnight study filed in this proceeding are summarized below.

Table 24: Goodnight Benchmark FTE

Nuclear FTE	2011	2013	2014
OPG Functional Staff	5,956	5,587	5,421
Goodnight Benchmark	5,090	5,193	5,208
Variance	**866**	**394**	**213**

OPG stated that 2016 staffing levels were at benchmark as OPG sustained higher than expected attrition and experienced hiring lags.[104] As the industry benchmark levels have risen and will continue to rise due to regulatory factors such as increased security

[104] Tr Vol 13 page 49.

needs, cybersecurity, Fukushima, etc., it is OPG's view that the test period staffing levels are appropriate.

Goodnight benchmarked OPG nuclear staff who supported steady state operations. A large number of staff were excluded, including those responsible for CANDU specific work, DRP, and corporate support not directly supporting the nuclear program. Goodnight did, however, benchmark certain contractors who provide baseline support.

The Society agreed with OPG's analysis of 2016 staffing levels and listed initiatives underway to improve efficiency in its submission. OEB staff and SEC questioned whether OPG had achieved benchmark staffing levels in 2016 as only 60% of nuclear staff were benchmarked, and also questioned the level of nuclear staffing in the test period.

Findings

The evidence in this proceeding demonstrates that OPG has made some positive steps towards controlling its overall compensation costs, both in terms of the amount it pays in relation to the relevant benchmarks, and the overall number of employees. However, for the reasons provided below, the OEB finds that forecast total compensation is in the range of $40 million to $50 million too high for each year of the test period. The OEB's findings on OM&A reflect this finding. As there is some overlap between corporate allocated costs and overall compensation the OEB will reduce nuclear OM&A by $30 million per year with respect to overall compensation

The OEB will not make any specific disallowances on account of nuclear operations staffing levels. Although the levels arguably remain slightly high in some areas, and the benchmarking results continue to show slight overstaffing, the OEB is satisfied that OPG has made significant progress since 2011. The Business Transformation Initiative achieved significant results. However, the OEB is concerned that the gains made through Business Transformation should be maintained, and cautions that OPG must remain vigilant and ensure staffing levels remain appropriate. The OEB will continue to review this area carefully in future proceedings, and believes there may still be room for improvement.

This is distinct from the nuclear allocated corporate employee levels which appear to be too high, although a conclusion on appropriate staffing levels cannot be made as the corporate costs benchmarking discussed in section 5.8 reviews overall costs and does not distinguish between staffing levels and compensation per employee. The OEB's findings on corporate allocated costs can be seen above.

Much of the benchmarking and other analysis divided OPG's compensation package into two broad categories: total direct compensation (wages, bonuses and other allowances), and pensions and benefits. The OEB will examine each of these categories in turn.

Total Direct Compensation

Benchmarking

OPG has been conducting benchmarking of its compensation costs for many years. In this proceeding OPG filed a comprehensive compensation benchmarking study prepared by WTW (the WTW Report). The WTW Report reviewed both total direct compensation, and pensions and benefits.

The WTW Report divided OPG's workforce into PWU, Society, and management. It further divided job types into three broad categories: utility, nuclear authorized, and general industry. Although there was considerable variation when considering both employee type and job type, overall, WTW found that OPG paid approximately 5% more than the comparable benchmarks. Given the nature of benchmarking analysis, WTW considers +/- 10% to be within benchmark, and by that measure OPG is essentially at benchmark.

The OEB accepts that, as a general matter, benchmarking provides high level, directional analysis, and should not be expected to measure precisely what OPG should be paying its employees. As described below, however, the OEB does not accept all the results of the benchmarking as being appropriate targets for OPG and will make findings to reduce revenue requirement accordingly. In particular, the OEB has concerns with respect to aspects of compensation that were excluded from the analysis (in particular lump sum payments and the share purchase plan), the relative paucity of workers that were benchmarked in the "general industry" category, as well as the use of 75th percentile rather than 50th percentile to benchmark the nuclear authorized category of employees.

In exchange for certain concessions to pensions and benefits that were negotiated in the most recent round of collective bargaining, OPG agreed to make certain lump sum payments and make available a share purchase plan to its unionized employees. The total cost of these measures for the regulated nuclear business over the test period is $92 million. WTW did not include these payments in its analysis of total direct compensation as they benchmarked 2015 and the lump sum payments and share purchase plan started for the PWU in 2016 and for the Society in 2017. OPG also noted that WTW does not routinely collect this type of data from organizations, and therefore could not benchmark it.[105]

The OEB's view is that the lump sum payments and share purchase plan should be added to the compensation benchmarked by WTW as they form part of the actual direct compensation that OPG's employees receive during the test years. They form a small but material portion of employee compensation and therefore should be accounted for.

The OEB is also concerned about the relatively few positions that WTW was able to benchmark under the "general industry" category. The general industry group includes workers that do not require particular utility or nuclear authorized specialized skills – the comparators selected by WTW were both private and public positions that required a large range of skill sets, with an emphasis on large Ontario employers. The WTW analysis showed that OPG greatly overcompensated its unionized workers under this category compared with its peers: both PWU and SEP were 27% above the benchmark. Unfortunately WTW was only able to benchmark 69% of general industry positions for the PWU (versus 81% of PWU positions overall) and only 51% of general industry positions for the Society (versus 74% overall). General industry positions, therefore, are proportionately under-represented in the study. The OEB believes that it is reasonable to infer that this tends to skew the overall results somewhat – had more general industry positions been included in the analysis, it appears that OPG might be more than 5% above market.

Although the 50th percentile is used as the benchmark for most positions, OPG chose (with WTW's support) to use the 75th percentile as the appropriate comparator for its nuclear authorized segment. OPG argued that this was appropriate because of the challenges associated with CANDU technology, and the fact that OPG's operators worked in stations with four (Darlington) and six (Pickering) units, whereas most of the comparators had only one or two units.

The OEB does not accept this rationale, and finds that the appropriate comparator for the nuclear authorized segment (and all segments) should be the 50th percentile. As its name suggests, the nuclear authorized segment is composed of staff working in a nuclear plant environment with specialized nuclear skills. That is the very reason they were chosen as comparators. Neither OPG nor WTW provided a convincing rationale as to why the number of units or the CANDU technology would mean that OPG's nuclear authorized workers should be entitled to higher compensation than other nuclear authorized workers, let alone to the 75th percentile.

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[105] Reply Argument page 146.

The OEB finds that there should be disallowances reflected in nuclear revenue requirement related to nuclear compensation being over the 50th percentile. Parties argued that the evidence supports disallowances in the range of $30 million[106] to $47 million.[107]

Both OPG and the PWU submitted that Bruce Power is OPG's closest comparator for compensation. Bruce Power operates CANDU units in Ontario and is staffed by the same unions. The WTW benchmarking shows that Bruce Power provides higher wages for the PWU and Society. While this compensation information for Bruce Power is informative, the OEB finds that it is of limited value. The data relate to wages, not overall compensation, and therefore provide only part of the overall picture. OPG has not filed a nuclear operations benchmarking study for Bruce Power to inform the OEB about Bruce Power's overall nuclear performance relative to OPG, in other words the OEB does not have information about Bruce's relative efficiency. The OEB also finds that the broader compensation report by WTW, which includes many operators, is more informative than OPG's one to one comparison with Bruce Power.

Pensions and benefits

OPG offers its employees a comprehensive package of benefits (for both current employees and retired employees), a generous registered pension plan, and a supplemental pension plan. The costs for these programs vary depending on whether the cash or accrual accounting method is employed, but in any event amounts to hundreds of millions of dollars per year. This is a significant component of OPG's overall revenue requirement.

The OEB finds that OPG's overall pension and benefits costs are clearly excessive, and it will make disallowances as described below. There is voluminous evidence demonstrating that the costs of these programs are well above market. It would not be reasonable, in the OEB's view, to require ratepayers to pay these excessive costs.

Benchmarking

The WTW report included a section on pensions and benefits. It concluded that the overall value of OPG's pension and benefits programs was well above market median – in fact 32% above.[108]

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[106] JT3.2.
[107] SEC Submission page 89.
[108] Exh F4-3-1 Attachment 2, page 27.

OPG also retained AON Hewitt to prepare a Benefit Index Report. Although many of the details of this report have been found by the OEB to be confidential and therefore cannot be disclosed on the public record, the overall conclusions reached were similar to those from the WTW Report: OPG's pre- and post-retirement benefits were amongst the most generous of all the companies measured, and were (overall) 11% above market.

It is not only the OEB that has shown concern about the cost of OPG's pension plan. The Leech Report was commissioned by the provincial government to review the sustainability and affordability of a number of public sector pension plans, including OPG's. The report was released in 2014 and contained some troubling findings, including that OPG's defined benefit pension plan was generous, expensive and inflexible, that it was not offset by lower salaries, and that the plan was "far from sustainable". It stated that OPG should aim to achieve a 1:1 employer:employee contribution ratio by about 2019.

The Auditor General of Ontario has also commented on OPG's pension plans, in particular its contribution ratio. In its 2013 report the Auditor General noted that OPG's contribution ratio was between 4:1 and 5:1, whereas in the Ontario public service generally it was 1:1.

OPG has made some improvements to the sustainability and affordability of its pension plan, but the OEB is not satisfied with OPG's contribution ratio over the test period.[109]

The OEB remains concerned about OPG's high pension and benefits costs. Although some improvement has been made, OPG's costs remain well in excess of its comparators. The contribution ratio for 2017 is at least 2:1, double that recommended by the Auditor General, the Leech Report, and the OEB in previous proceedings. The expected contribution ratio throughout the rest of the test period was filed in confidence, but is known to the OEB and the parties that signed the OEB's Undertaking with respect to confidentiality.[110] The OEB also notes that the record is not clear with respect to the calculation of employer:employee contribution ratios. The OEB recognizes that any savings to pensions and benefits costs need to be negotiated with OPG's unions, and that this can be a slow and difficult process. Ultimately, however, the question becomes who should pay for these excessive costs: the shareholder or ratepayers? The OEB

[109] Much of the information relating to the specific expected contribution ratio in specific years was filed confidentially, and therefore cannot be discussed in detail in this publicly issued Decision. However, underlying information in support of this finding can be found, for example, at Ex. L, Tab 6.6, Schedule 1, Staff-157; Exhibit L, Tab 6.6, Schedule 1, Staff-157, and Transcript volume 16, pages 163-171.
[110] *Ibid*.

finds that there should be disallowances reflected in nuclear revenue requirement related to excessive pension and benefits costs. The precise amount is difficult to estimate as OPG indicated that it was not able to calculate the revenue requirement impact of having its overall pension and benefits plans at benchmark. However, the OEB finds it could be at least as high as $20 to $30 million per year.

Conclusion with respect to compensation

Although OPG has made some progress in controlling its overall compensation costs, overall the costs remain above benchmark and are not reasonable. For the reasons enumerated above, the OEB will reduce OPG's overall OM&A budget by $30 million per year on account of excessive compensation. This includes direct compensation, and pensions and benefits. This is in addition to the disallowance of $45 million per year for excessive corporate allocated costs discussed in section 5.8. In making this finding the OEB has taken into account that the cumulative ranges of costs it has found to be excessive are approximately $100 million to $120 million per year. The OEB is confident that a combined reduction of $75 million will allow for any overlap between categories (compensation, pensions and benefits also apply to corporate allocated nuclear employees) and uncertainty about the benchmarking data and pension contribution calculations.

The OEB expects compensation benchmarking with the next cost based application. The benchmarking shall include a detailed overtime analysis. The OEB also expects a staffing benchmarking study that will incorporate contractor FTEs following the Goodnight methodology. In addition, OPG shall file pension and OPEB evidence that clearly sets out the elements included and excluded in its determination of employer:employee contribution ratios.

5.10 Depreciation

The EB-2010-0008 decision directed OPG to file an independent depreciation study in the next proceeding. The OEB accepted the evidence prepared by Gannett Fleming for EB-2013-0321. OPG states that its determination of depreciation and amortization in this is the same as in the previous proceeding. There have been no changes in asset service lives but the end of life for the nuclear stations have been revised.

The EB-2012-0002 and EB-2013-0321 payment amount orders require OPG to file an accounting order application if OPG proposes to change station end of life for depreciation and amortization purposes, the change impacts the calculation of nuclear liabilities (other than as a result of an ONFA Reference Plan update),[111] and the impact exceeds $10 million. At the end of 2014, OPG filed an accounting order application, EB-2015-0374, in which it advised the OEB that due to revisions in the DRP schedule, finalization of the Amended and Restated Bruce Power Refurbishment Implementation Agreement and confidence achieved through work on the Fuel Channel Life Extension Project relating to Pickering, station end of life has been extended. The OEB directed OPG to establish the Impact Resulting from Changes in Station End-of-Life Dates (December 31, 2015) Deferral Account. The change in nuclear station end of life is summarized in the following table.

Table 25: Nuclear Station End-of-Life

	Effective January 1, 2013	Effective December 31, 2015
Darlington	December 31, 2051	December 31, 2052
Pickering Units 1&4	December 31, 2020	December 31, 2020
Pickering Units 5-8	April 30, 2020	December 31, 2020
Bruce A Units 1-4	December 31, 2048	December 31, 2052
Bruce B Units 5-8	December 31, 2019	December 31, 2061

Source: Exh F4-1-1, page 3

The historical and proposed test period depreciation and amortization are summarized in the following table. The increase in 2020 is related to the planned return to service of Darlington Unit 2, while the decrease in 2021 reflects the current end of life of Pickering, i.e. December 31, 2020. The Exh N1-1-1 impact statement reflected the accounting impacts of the 2017 ONFA Reference Plan, while the Exh N2-1-1 impact statement reflected the impact of excluding the capital in-service amounts for the D2O project.

Table 26: Depreciation and Amortization

$million	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Application as filed	270.1	285.3	298.0	293.6	346.9	378.7	384.0	524.9	338.1
Exh N1-1-1 - Change in ARC Amortization					27.0	27.0	27.0	27.0	-10.8
Exh N2-1-1 - Change in Depreciation for D2O Project					-6.9	-10.7	-10.7	-10.7	-10.7
Depreciation and Amortization	**270.1**	**285.3**	**298.0**	**293.6**	**367.0**	**395.0**	**400.3**	**541.2**	**316.6**

No submissions were filed objecting to the calculation of depreciation expense. While OPG's next independent review of service life would be scheduled for 2018, OPG

[111] ONFA refers to the Ontario Nuclear Funds Agreement, which is discussed below.

proposed to file the study after Darlington Unit 2 is scheduled to return to service in 2020. The study would be conducted in 2021 and would be based on 2020 year-end asset net book values. OEB staff did not oppose the delay in filing the independent review as there is the requirement to file an accounting order in the event of material change in service life, and regular review of station life and certain asset classes by OPG's Depreciation Review Committee.

Findings

The depreciation expense in the application reflects December 31, 2020 end of life for Pickering while the balance of the application reflects Pickering life to 2022 - 2024. The OEB notes that a similar circumstance occurred in the EB-2010-0008 proceeding wherein depreciation expense reflected Pickering life to 2014 - 2016, while the application also sought expense related to Pickering 2020. Previous payment amount orders have established that OPG will apply for an accounting order if there are material changes to service life estimates.[112] The OEB finds that there is no compelling reason to deviate from these previous depreciation treatments.

OPG states that it will not conduct an independent review of service life in 2018, but will conduct the review in 2021 after the completion of Darlington Unit 2 refurbishment. The OEB has no concerns with the proposal.

The depreciation expense that underpins the nuclear test period revenue requirement will reflect the OEB's findings elsewhere in this Decision.

5.11 Income and Property Taxes

5.11.1 Background

OPG uses the taxes payable method for determining regulatory income tax for the regulated facilities. Regulatory income taxes are determined by applying the statutory tax rates to the regulatory taxable income of the regulated facilities and reducing the resulting amount by recognized investment tax credits (ITCs) for qualifying Scientific Research and Experimental Development (SR&ED) expenditures. OPG states that its determination of income tax expense in this proceeding is the same as in the previous proceeding. The historical and proposed income tax and property tax for the nuclear business are summarized in the following table.

[112] EB-2012-0002 and EB-2013-0321.

Table 27: Income and Property Tax

$million	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Income Tax Expense	-76.4	-61.5	-31.8	-18.7	-6.7	-18.4	-18.4	59.2	-5.0
Property Tax Expense	13.6	13.2	13.2	13.5	14.6	14.9	15.3	15.7	17.0

Source: Exh F4-2-1 Table 2, Exh N2-1-1

The negative expense in four years of the test period is largely the result of forecast SR&ED ITCs and carryover of projected regulatory tax losses arising in 2018 and 2019. The increase in 2020 is related to impacts associated with return to service of Darlington Unit 2. Submissions were filed on utilization of SR&ED ITCs and property tax. The decrease in 2021 is largely due to a reduction in depreciation and amortization expense related to the Pickering station.

5.11.2 SR&ED ITCs

OEB staff noted that in the period 2013 to 2015, the nuclear business was attributed losses for tax purposes. Therefore, the nuclear SR&ED ITCs were applied against hydroelectric taxes during this period. OPG has forecast $18.4 million of SR&ED ITCs for regulatory purposes annually over the test period to reduce regulatory tax expenses.[113] As the hydroelectric payment amounts will be set by an IRM formula in the test period, OEB staff submitted that the SR&ED ITCs should be utilized by the business segment that earned the ITCs and be carried forward if unused in a particular year. OEB staff submitted that this would be consistent with the cost causation regulatory principle.

OEB staff also observed a consistent variance (i.e. under-forecasting) between forecast SR&ED ITCs and actual for the period 2013 to 2015, and between forecast SR&ED ITCs in the test period and credits included in the most recent OPG business plan. OEB staff submitted that the credits in the most recent business plan should underpin revenue requirement and that the existing Income and Other Tax Variance Account could record variances between forecast and actual. LPMA supported the OEB staff submission.

OPG replied that external specialists review expenditures to identify qualifying work for SR&ED ITC claims. It is not possible to forecast ITCs with a high level of precision. However, OPG did not object to prospectively truing up nuclear SR&ED ITCs using a new SR&ED ITC variance account. OPG submitted that using the Income and Other

[113] Exh N2-1-1, Table 2.

Tax Variance Account would be inconsistent with the OEB approved settlement agreement and with the original intent of that account.

With respect to carry-forwards, OPG replied that this approach would not consistently produce a full true up outcome, and could result in double counting if the proposed variance account is approved. OPG also replied that adjusting the test period revenue requirement for SR&ED ITCs to reflect the most recent OPG business plan would be arbitrary and selective. Should the OEB proceed with the new variance account, the adjustment would not be required.

Findings

The OEB is asked to consider the utilization of SR&ED ITCs against regulatory tax expense. The matter has been made more complex by the different rate-setting methodologies in the test period for the hydroelectric and nuclear businesses.

The OEB accepts OPG's position that it is difficult to forecast ITCs with precision as determinations of qualified SR&ED claims are made by external specialists after the fact.[114] The OEB finds that the carry-forward mechanism proposed by OEB staff introduces complexities and may not produce a full true-up effect.

While the 2017-2019 business plan forecasts SR&ED ITCs that are higher than the application, the OEB has determined that a true-up mechanism is the appropriate way to deal with the SR&ED ITCs in the test period. The OEB agrees that a new account is required as the purpose of the existing Income and Other Taxes Variance Account is to record variances related to changes in tax rates or rules, new administrative practices and assessments. The new SR&ED ITC Variance Account will record the tax expense impact as a result of the difference between actual SR&ED ITCs as determined after any tax audits and the forecast SR&ED ITCs included in payment amounts for the nuclear business. The new account will be effective as of the effective date for payment amounts in this proceeding. The OEB directs OPG to file a draft accounting order for the new variance account.

The rate-setting methodologies for the hydroelectric and nuclear businesses beyond 2021 are not certain. OPG's next application should consider the utilization of SR&ED ITCs and explain its proposal. However, the OEB notes that the majority of SR&ED ITCs are earned by nuclear. The 2013-2016 hydroelectric SR&ED ITCs was about $0.2 million per year.[115]

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[114] Reply Argument page 169.
[115] Exh L-6.10-Staff-188.

The income taxes that underpin the nuclear test period revenue requirement will reflect the OEB's findings elsewhere in this Decision.

5.11.3 Property Tax

LPMA noted that the OEB approved property tax for the nuclear business for 2014 and 2015 were 11% and 20%, respectively, higher than the actual costs. This amounted to $1.8 million in 2014 and $3.2 million in 2015. LPMA submitted that the OEB should either reduce the property taxes by $2 million per year to reflect the tendency to over forecast these costs, or include the property taxes in the costs to which the stretch factor is applied.

OPG replied that inputs to the forecast of property tax are unchanged from previous proceedings. OPG further noted that 2016 property taxes were higher than budget.

Findings

The OEB has reviewed the LPMA submission proposing a reduction in the property tax forecast or inclusion in the expenses subject to the Custom IR stretch factor. On the basis of OPG's application and the reply argument stating that 2016 property tax was higher than budget, the OEB is satisfied that the property tax proposed for the test period is appropriate.

5.12 Bruce Lease – Revenues and Costs

OPG leases the Bruce A and Bruce B generating stations and associated lands and facilities to Bruce Power. Sections 6(2)9 and 6(2)10 of O. Reg. 53/05 set out the payment amount requirements related to Bruce:

> 6(2)9 The Board shall ensure that Ontario Power Generation Inc. recovers all the costs it incurs with respect to the Bruce Nuclear Generating Stations.
>
> 6(2)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.

The EB-2007-0905 decision found that the Bruce nuclear facilities should not be treated as if they were regulated facilities. The current basis of accounting used for the Bruce nuclear facilities revenues and costs is USGAAP for non-rate-regulated entities. The

EB-2007-0905 decision also approved the Bruce Lease Net Revenues Variance Account.

On December 3, 2015, the Province announced that an updated contract had been executed between the IESO and Bruce Power to enable the refurbishment of Bruce Units 3-8 (the Amended and Restated Bruce Power Refurbishment Implementation Agreement). In support of these planned refurbishments, an amended Bruce lease agreement was executed by OPG and Bruce Power on December 4, 2015 (2015 Lease Amendment) that extended the lease period in line with the estimated post-refurbishment end-of-life dates of the Bruce units.

The historical and forecast Bruce Lease net revenues are summarized in the following table. The Exh N1-1-1 impact statement revised the test period net revenues for the 2017 ONFA Reference Plan. As discussed in section 5.13 regarding nuclear liabilities, the ONFA Contribution Schedule was approved on February 28, 2017. In Undertaking J21.2, OPG provided the impact of the new contribution schedule and a further revenue requirement reduction related to a year end adjustment to the asset retirement obligation. OPG proposed to record the difference between Exh N1-1-1 and Undertaking J21.2 in the Bruce Lease Net Revenues Variance Account.

Table 28: Bruce Lease Revenues and Costs

$million	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Revenues	228.4	307.5	491.0	237.4	216.0	210.9	208.5	219.8	188.7
Costs	222.3	202.2	315.2	303.4	232.9	228.0	235.9	243.5	226.8
Net (Exh G2-2-1, N1-1-1)	**6.1**	**105.3**	**175.8**	**-66.0**	**-16.9**	**-17.1**	**-27.4**	**-23.7**	**-38.1**
Net (Undertaking J21.2)					**-5.5**	**-7.3**	**-20.6**	**-20.0**	**-40.3**

Source: Exh G2-2-1 Table 1, Exh N1-1-1 Table 7, Undertaking J21.2 Attachment 1 Table 1

OAPPA submitted that 50% of the proposed Bruce Lease Net Revenue loss should be disallowed. OAPPA argued that the principal reason for the underlying loss is the 2015 Lease Amendment which was negotiated with a privately owned, unregulated corporation. OPG argued that OAPPA's submission has no legal merit, and referred to the requirements of O. Reg. 53/05 with respect to cost recovery for the Bruce facilities.

As noted in the Nuclear Liabilities section, section 5.13, OEB staff and several intervenors submitted that the impacts of the new ONFA Contribution Schedule and year end asset retirement obligation adjustment should be reflected in revenue requirement and not in variance accounts. OPG does not oppose these submissions.

The question of whether OPG's forecast of non-energy revenues to be derived from its nuclear business other than the Bruce Lease Net Revenues (issue 7.1) was fully settled.

Findings

The OEB agrees with the parties that the impact of the new ONFA Contribution Schedule and year end ARO adjustment should be reflected in revenue requirement and not recorded in the Bruce Lease Net Revenues Variance Account. While the information and update related to nuclear liabilities was only available in February 2017, the OEB finds that there is no reason not to reflect current information in the revenue requirement. The net amounts of the Bruce lease revenues and costs as set out for the test period in Undertaking J21.2 are approved. The OEB's findings with respect to nuclear liabilities, including revenue requirement methodology, are in section 5.13.

The OEB rejects OAPPA's submission to disallow 50% of the proposed Bruce Lease Net Revenue loss. The OEB's role with respect to Bruce revenues and costs is set out in O. Reg. 53/05. Section 6(2)9 of O. Reg. 53/05 is clear that the OEB must ensure recovery of all the costs OPG incurs with respect to the Bruce Nuclear Generating Stations.

5.13 Nuclear Liabilities

Background

OPG is responsible for ongoing and long-term management of nuclear waste and decommissioning of Pickering, Darlington and the Bruce Nuclear Generating Stations. The cost of nuclear liabilities is determined by the Ontario Nuclear Funds Agreement (ONFA) Reference Plan which is updated every five years. The ONFA sets out OPG's funding obligations for nuclear liabilities through contributions to two segregated funds: the Decommissioning Fund and the Used Fuel Fund. The present value of the costs is recorded as an Asset Retirement Obligation (ARO) in OPG's financial statements.

In addition to the ONFA, O. Reg. 53/05 sets out requirements related to nuclear liabilities and Bruce. The definition section sets out that "nuclear decommissioning liability" means the liability of OPG for decommissioning its nuclear generation facilities and the management of its nuclear waste and used fuel:

> Section 5.2
>
> Nuclear liability deferral account
>
> (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.
>
> Section 6(2)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.
>
> Section 6(2)9
>
> The Board shall ensure that Ontario Power Generation Inc. recovers all the costs it incurs with respect to the Bruce Nuclear Generating Stations.

The revenue requirement methodology for nuclear liabilities is complex and was established in the first payment amounts proceeding, EB-2007-0905. The recognition of an ARO for accounting purposes gives rise to offsetting capitalized costs called the Asset Retirement Cost (ARC), and the value recorded for the ARO grows with the passage of time (accretion expense). The EB-2007-0905 decision approved a methodology that recognizes a return on rate base associated with ARC for Pickering and Darlington that is limited to the weighted average accretion rate, which is currently 4.95%.[116] This accretion rate is applied to the lesser of the forecast average unfunded nuclear liabilities (UNL) or the average unamortized ARC. In addition, the portion of unamortized average ARC in excess of the average UNL, if any, receives a return on rate base at the approved weighted average cost of capital. Other costs approved for recovery are the annual depreciation and amortization related to the ARC, and annual costs related to incremental nuclear waste generated by the operating facilities in each period (the latter is also referred to as internally funded nuclear liability programs).

For Bruce, which is not rate-regulated by the OEB, a GAAP based approach was approved. The Bruce methodology is similar to that used for Pickering and Darlington with the main distinction being that the Bruce methodology does not provide for a return on rate base. Instead, it recognizes the GAAP based accretion expense on the ARO less the earnings on the segregated funds. The EB-2007-0905 methodologies have been applied in all subsequent payment amount proceedings.

[116] Exh N1-1-1.

Application

The application as originally filed on May 27, 2016, was based on the 2012 ONFA Reference Plan. OPG sought recovery of $2,293.4 million for nuclear liabilities in the test period for the regulated nuclear facilities and for Bruce.

As part of the impact statement filed on December 20, 2016, OPG calculated the projected cost impacts and revenue requirement impacts of the 2017 ONFA Reference Plan which was approved by the Province in December 2016. The revenue requirement for nuclear liabilities was revised to $1,808.0 million. The major contributing factor to the reduction is lower used fuel disposal costs reflecting a “new, more cost effective container design and engineered barrier concept to house used nuclear fuel for disposal, as well as a later planned in-service date for Canada’s proposed used fuel deep geologic repository.”[117]

The Province subsequently approved the ONFA Contribution Schedule on February 28, 2017. As described in an update to Exh C2-1-2 filed on March 22, 2017, the nuclear liabilities in aggregate are fully funded from an ONFA perspective, however the funding obligations related to the regulated facilities were underfunded while those related to the Bruce facilities were overfunded. The approved ONFA Contribution Schedule rebalances the funds at a station level. The after tax impact of the contribution change is a reduction in the revenue requirement of $170.8 million for the regulated facilities, offset by a decrease in Bruce lease net revenues of $51.2 million.

In Undertaking J21.2, OPG provided a summary of the complete revenue requirement impact of the contribution change, plus a further $185 million reduction to the revenue requirement primarily due to a year end adjustment to its asset retirement obligation as reflected in its 2016 audited consolidated financial statements. The net after tax result is a decrease of $304.7 million and a total nuclear liability revenue requirement of $1,503.3 million. As these changes occurred late in the proceeding, OPG proposed that the impacts be recorded in the Nuclear Liability Deferral Account and the Bruce Lease Net Revenues Variance Account. However, in cross-examination, OPG stated that the net credit could alternatively be reflected in the payment order process.[118] OEB staff and several intervenors submitted that the impacts should be reflected in test period revenue requirement.

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[117] Exh N1-1-1 page 14.
[118] Tr Vol 21 pages 42-43.

Status of the Segregated Funds

On January 19, 2017, SEC requested additional written evidence on the funded status of the segregated funds. SEC's position was that its review of the Exh N1-1-1 impact statement filed on December 20, 2016 demonstrated that a segregated fund contribution holiday had arisen. In Procedural Order No. 6, issued on January 27, 2017, the OEB ordered OPG to file additional evidence on the status of the segregated funds and the interaction to date between amounts recovered and the fund status. OPG filed Exh C2-1-2, Nuclear Waste Management and Decommissioning – Supplementary Information, on February 14, 2017. The supplementary information states:

> As at December 31, 2016, the Decommissioning Segregated Fund ("DF") was overfunded at approximately 121% and the Used Fuel Segregated Fund ("UFF") was marginally overfunded at less than 1%, relative to the corresponding funding obligations per the 2017 ONFA Reference Plan. As reflected in Ex. N1-1-1, OPG expects this to result in overall zero required contributions to both funds until the next ONFA reference plan is approved.

Submissions on Methodologies

The parties generally refer to the current approved recovery methodologies as accounting based methodologies. CCC, CME,[119] LPMA and SEC submitted that the nuclear liability revenue requirement methodology should be calculated on a cash basis, i.e. representing the sum of the ONFA contribution requirements and the annual cash expenditures for internally funded nuclear liability programs. Implementation of this submission would reduce test period revenue requirement by $423.2 million.[120] CME submitted that this amount is not needed to fund present nuclear liabilities and is not necessarily going to be needed to fund future nuclear liabilities. SEC argued that as OPG does not have to make any contributions to the segregated funds, these payments could be used as general funds. The intervenors also argued that $108 million has been over-collected for the period from April 1, 2008 (the effective date of the OEB's first payment amounts order) to December 31, 2016 due to the historical variance of accounting versus cash amounts.[121] SEC and CME also raised concerns about tax impacts and inconsistent tax treatment.

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[119] CME's submission refers to a $314 million reduction.

[120] Undertaking J21.2, Chart 1, line 11 – revenue requirement reflecting approved contribution schedule: $1,503.3 million.
Undertaking J20.8, Chart 1, lines 6 and 14 – amounts forecast to be expended: $1,155.2 million-$75.1 million = $1,080.1 million.
Difference: $1,503.3 million-$1,080.1 million = $423.2 million.

[121] Undertaking J20.7.

OPG argued that the matters raised by the intervenors are not new. Nuclear liability revenue requirement methodologies were reviewed extensively in the EB-2007-0905 proceeding. OPG argued that the cash methodology was reviewed in the EB-2007-0905 proceeding, but not approved. OPG also argued in reply that the Decommissioning Fund has been in an overfunded position for the entire period of the OEB's payment amount jurisdiction, and that the EB-2007-0905 decision contemplated that the segregated funds would be fully funded in the future. With respect to the variance analysis that compares amounts collected in payment amounts to cash spent on nuclear liabilities, OPG submitted that the amounts collected in interim payment amounts set by the Province for the period April 1, 2005 to March 31, 2008 were $994 million lower than the amounts expended for nuclear liabilities.[122]

The EB-2007-0905 decision approved a GAAP-based methodology for Bruce as it is not rate-regulated. OPG submitted that maintaining a GAAP-based methodology for Bruce, but changing to a cash-based methodology for Pickering and Darlington would increase the revenue requirement by $634 million.[123]

CCC and CME submitted that there are no transition issues and that OPG would not be harmed should the OEB approve a change in methodology. OPG argued that there are many transition issues and compared them to the principles considered in the OEB's consultation on Pension and Other Post-Employment Benefits.[124]

There is a difference in the discount rate applied to determine the ARO for financial reporting purposes and the ONFA funding liability. SEC submitted that the liabilities on the OPG balance sheet are $2.2 billion too high (compared to the ONFA Funding Liability) due to this discount rate difference. OPG replied that the rates are different and serve different purposes, and that the difference has existed since EB-2007-0905. The ARO on OPG's balance sheet is determined in accordance with USGAAP and the ONFA Funding Liability is determined based on the ONFA Agreement.

OEB staff submitted that a study of nuclear liability revenue requirement methodologies and discount rates for ARO and ONFA funding liability could be filed in the next payment amounts proceeding. CME submitted that it is unjust to ask ratepayers to pay more than the cash amounts while the OEB is preparing to study the issues. OPG replied that it saw no need to undertake the study, but did not oppose the request.

[122] Undertaking J20.7.
[123] AIC pages 182 and 189.
[124] EB-2015-0040.

Findings

Nuclear Liability Revenue Requirement Methodology

CCC, CME, LPMA and SEC argue that the revenue requirement methodology should be changed from the current methodology (return on rate base for Pickering and Darlington, GAAP for Bruce) to a cash-based methodology. As there are no forecast contributions to the segregated funds in the test period per the 2017 ONFA Reference Plan, the current methodology results in revenue requirement that exceeds forecast nuclear liability cash expenses by $423.2 million.

In addressing this, the OEB considered that the nuclear liability revenue requirement methodology is a substantive matter involving a large expense that is considered over a timeframe that is measured in decades. A change to the nuclear liability revenue requirement methodology requires consideration of many factors – including accounting, funding and rate-making. This is not a simple task, as the following issues must be addressed:

- The ONFA is a bilateral agreement between OPG and the Province. OPG states that the ONFA funding requirements are not necessarily designed as a measure of OPG's costs or payments from ratepayers[125]
- O. Reg. 53/05 sets out certain requirements related to nuclear liabilities
- The current revenue requirement methodology for the regulated nuclear facilities differs from the methodology for Bruce
- The variance between amounts expended on nuclear liabilities and amounts recovered has been both positive and negative in the historical period
- The EB-2007-0905 decision observed that "there does not appear to be any consistent and generally accepted treatment of AROs and ARCs in other North American jurisdictions"[126]

The OEB finds that the evidence and testing of the evidence in this proceeding is insufficient to consider changing the revenue requirement methodology for nuclear liabilities at this time. The OEB understands the concerns that $423.2 million is forecast to be recovered in the test period that is in excess of forecast nuclear liability cash requirements. The OEB also observes that in the period 2009 to 2011, the amounts recovered for nuclear liabilities were considerably lower than requirements.[127] However,

[125] Reply Argument page 190.
[126] EB-2007-0905 Decision with Reasons, November 3, 2008, page 88.
[127] Undertaking J20.7 Chart 1.

on the basis of the evidence and argument in this proceeding, the OEB is not prepared to order a revision to the methodology established in the EB-2007-0905 proceeding.

Some parties made reference to aspects of the EB-2007-0905 decision in their argument which were not raised during the hearing. OPG noted that the submissions of some parties differ from submissions these parties made in EB-2007-0905.[128] The OEB also finds that the parties advocating a cash based methodology did not sufficiently explain why the cash based methodology is superior in the long term.

In addition to submitting that the revenue requirement methodology should not include amounts in excess of ONFA contributions and variable costs, CCC, CME and SEC also raised issues about tax implications. CCC submitted that the revenue requirement methodology is flawed because the tax consequences result in higher revenue requirement when the contributions to ONFA are lower. The OEB does not find this to be a compelling reason to change methodologies. The tax impacts are based on the application of tax rules.

OEB staff submitted that OPG should provide a jurisdictional study of cost recovery methodologies for nuclear liabilities with its next cost based nuclear payment amounts application. The OEB agrees that this study should be filed. The study should also include an examination of cost recovery for short term and long term nuclear liabilities as it relates specifically to OPG's assets.

The OEB also directs OPG to report annually by June 30 on expenses related to nuclear liabilities. The form of the reporting will be that set out in Chart 1 of undertaking J20.7. The expenses should separately identify ONFA expenses and internally funded expenses. The time period of the report should start at April 1, 2008 at the latest. The annual filings will assist parties with their preparation for future proceedings should they wish to advocate for a change to the current nuclear liability revenue requirement methodology.

Discount Rates

The ARO and ONFA funding liabilities are calculated using different discount rates which results in a difference in liabilities of $2.2 billion. CME and SEC submitted that OPG's ARO discount rate should be reduced to match the ONFA discount rate. OEB staff submitted that the matter could be reviewed as part of a comprehensive study of methodologies. OPG argued that that discount rates have been examined previously and noted in the EB-2007-0905 decision OPG submitted that historically the rates have

[128] Reply Argument, page 184-186.

varied and that in previous years the ONFA funding discount rate was lower than the ARO discount rate.[129]

The OEB acknowledges that the discount rates may be different at any given time and that they serve different purposes. If parties wish to examine the matter as part of the consideration of nuclear liabilities cost recovery methodology they may do so in a future proceeding.

Revenue Requirement

The OEB approves a test period nuclear liability revenue requirement of $1,503.3 million.

As explained above in section 5.12 regarding the Bruce Lease, the OEB agrees with the parties that the impact of the new ONFA Contribution Schedule and year end ARO adjustment should be reflected in the revenue requirement and not recorded in the Nuclear Liabilities Variance Account.

[129] Reply Argument page 186-187.

6 CAPITAL STRUCTURE AND COST OF CAPITAL

6.1 Capital Structure

OPG applied for a deemed capital structure of 49% equity and 51% debt. The equity thickness is an increase from the current 45% approved in the previous cost of service proceeding. In that proceeding, the OEB found that the addition of 48 hydroelectric facilities to those regulated by the OEB, and the completion of the $1.5 billion Niagara Tunnel Project, lowered OPG's business risk and that a reduction in equity thickness from 47% to 45% was appropriate.[130]

The following table summarizes the applied for and approved equity thicknesses in previous proceedings before the OEB.

Table 29: Equity Thickness

Equity Thickness	EB-2007-0905	EB-2010-0008	EB-2013-0321
Applied for	57.5%	47%	47%
Approved	47%	47%	45%

OPG stated that the proposed 49% equity thickness reflects the material increase in business and financial risks since the previous proceeding. OPG filed the evidence of Concentric Energy Advisors (Concentric) to support its application. Concentric testified that OPG's risk profile has changed and will continue to change over the test period. While the risks for the hydroelectric business are stable, there are significant risks related to the DRP and PEO for the nuclear business and both businesses face regulatory risk related to the implementation of incentive regulation and recovery risk related to deferred pension and OPEB costs. While the equity thickness for Concentric's comparator group ranged from 40.27% to 54.29%, Concentric concluded that OPG as a generation only company with a significant nuclear concentration has elevated risk. Concentric concluded that 49%, at a minimum, is an appropriate equity thickness for OPG.

OEB staff retained the Brattle Group (Brattle) as an independent expert to review Concentric's analysis and to evaluate OPG business risks. Brattle agreed that there is significant construction and execution risk related to DRP, but gave little weight to Concentric's concerns about OPG's ability to recover its costs associated with pension and OPEB. Brattle considered a different comparator group than Concentric; it included companies with significant generation that was subject to regulation. In addition, Brattle

130 Decision with Reasons EB-2013-0321, November 20, 2014, pages 113-115.

analyzed OPG’s credit metrics. Brattle concluded that it would be reasonable to increase equity thickness to 48%.

Most intervenors submitted that the equity thickness should remain at 45%, however VECC submitted that 40 to 45% was appropriate, and OEB staff submitted that 47% was appropriate.

As the 2017-2021 hydroelectric payment amounts will be set under an IRM regime, OPG proposed a new Hydroelectric Capital Structure Variance Account to record the hydroelectric revenue requirement impact of the difference between the capital structure approved in this proceeding and the 45% equity thickness that underpins the hydroelectric payment amounts.

Findings

The OEB finds that OPG has not established that there is a change in business risk that warrants an increase in the level of equity to 49%. The equity level will remain at 45%.

The OEB makes this finding based on the evidence regarding OPG’s specific circumstances and the financial risks the OEB considers are actually faced by OPG, and a consideration of the level of equity that is appropriate for a Canadian utility to meet the fair return standard.

The Expert Evidence

Prior to giving evidence each of the experts was qualified and accepted as an expert by the hearing panel. All parties had an opportunity to raise any issues they might have regarding their expertise or independence. No issues of independence were raised by any party at that time. However, in final argument, at a stage in the proceedings when the experts could not respond, some intervenors suggested the experts lacked independence because they are typically retained by utilities. This is a serious allegation because an expert’s independence is an essential element of his or her reputation.

It is also inappropriate at the argument stage of a proceeding. There is no basis for such an allegation in this case. Any party who intends to challenge the independence or other aspects of an expert witness’s qualifications must do so before he or she is qualified to give expert evidence.

The OEB found both experts who testified on equity thickness to be forthright and helpful to the OEB’s understanding of the issue.

Issues Raised by the Experts

The main factors underlying the experts' recommendation that the equity thickness be increased were:

1. The change in OPG's portfolio between hydroelectric and nuclear generation due to DRP capital investments

2. Consideration of OPG's cost recovery risk due to existing protections provided by O. Reg. 53/05 and established deferral and variance accounts

3. The move to IRM from cost of service regulation for hydroelectric payments

4. Capital expenditures related to the DRP

5. Pickering extended operations

6. Revenue deferred under rate smoothing

7. Recovery risk associated with pension and OPEB costs

8. Credit risk

9. OPG's equity ratio in comparison to other utilities selected by each expert

The change in OPG's portfolio between hydroelectric and nuclear generation due to DRP capital investments

The OEB does not accept OPG's argument that because the equity ratio was reduced to 45% due to the increase in hydroelectric generation in the last rates case, the spending on the DRP and PEO over the next few years must necessarily mean the equity ratio must be increased. There is more to it than that.

The EB-2013-0321 decision deals with more than one aspect of the impact of the increase in the hydroelectric generation portfolio. The two factors were the increase in annual MWh generated by hydroelectric with the addition of 48 previously unregulated facilities to the regulated portfolio and the completion of the Niagara Tunnel, and the increase in hydroelectric rate base by the addition of these assets to the regulated portfolio. The OEB found, in that case, that there was less risk as hydroelectric is more stable, from a revenue perspective, than nuclear generation. This is in part due to the nature of the assets, and protections such as the Hydroelectric Water Conditions Variance Account required by O. Reg. 53/05.

In this case, while the nuclear rate base will increase substantially over the five-year term, the MWh generated by nuclear will not increase, and in fact will decrease at times as units are taken out of service at Darlington. The relative contributions of revenue from hydroelectric and nuclear will not change in favour of nuclear, so it is not axiomatic that the equity thickness should be increased on this basis.

Consideration of OPG's cost recovery risk due to existing protections provided by O. Reg. 53/05 and established deferral and variance accounts

The OEB accepts the opinions of both experts that, in general, there are more business risks associated with nuclear generation than with hydroelectric. However, in OPG's specific circumstances, there are a number of factors that substantially mitigate that risk. These include the various protections provided by O. Reg. 53/05 and the variance and deferral accounts that allow OPG the opportunity to recover substantially all their unexpected or unforeseen costs. These include:

Table 30: Nuclear Deferral and Variance Accounts[131]

Deferral and Variance Account	Established per
• Nuclear Liability Deferral Account	O. Reg. 53/05 section 5.2
• Nuclear Development Variance Account	O. Reg. 53/05 section 5.5
• Ancillary Services Net Revenues Variance Account – Nuclear sub-account	O. Reg. 53/05 section 5(1)(c)
• Capacity Refurbishment Variance Account – Capital Nuclear sub-account	O.Reg. 53/05 section 6(2)(4) – given eff ect by CRVA in Decision with Reasons EB-2007-0905
• Capacity Refurbishment Variance Account – Non-capital Nuclear sub-account	O. Reg. 53/05 section 6(2)(4) – given effect by CRVA in Decision with Reasons EB-2007-0905
• Bruce Lease Net Revenues Variance Account – Derivative sub-account	O. Reg. 53/05 section 6(2)(9) – given effect in Decision with Reasons EB-2007-0905 and Decision EB-2012-0002
• Bruce Lease Net Revenues Variance Account – Non-Derivative	O. Reg. 53/05 section 6(2)(9) – given effect in Decision with Reasons EB-2007-0905 and Decision EB-2012-0002
• Bruce Lease Net Revenues Variance Account – Non-Derivative Post 2012	O. Reg. 53/05 section 6(2)(9) – given effect in Decision with Reasons EB-2007-0905 and Decision EB-2012-0002
• Income and Other Taxes Variance Account – Nuclear sub-account	Decision with Reasons EB-2007-0905
• Pension and OPEB Cost Variance Account – Future Recovery – Nuclear sub-account	Decision and Order on Motion EB-2011-0090 and Decision EB-2012-0002
• Pension and OPEB Cost Variance Account – Post 2012 Recovery – Nuclear sub-account	Decision and Order on Motion EB-2011-0090 and Decision EB-2012-0002
• Pension and OPEB Cash versus Accrual Differential Deferral Account – Nuclear sub-account	Decisions with Reasons EB-2013-0321
• Pension and OPEB Cash Payment Variance Account – Nuclear sub-account	Decision with Reasons EB-2013-0321
• Pickering Life Extension Depreciation Variance Account	Decision EB-2012-0002
• Nuclear Deferral and Variance • Over/Under-Recovery Variance Account – Nuclear sub-account	Decision and Order EB-2009-0174
• Impact Resulting from Changes in Station End-of-Life Dates (December 31, 2015) Deferral Account	Decision and Order EB-2015-0374

[131] Exh H1-1-1.

OPG has also proposed some additional deferral and variance accounts in this proceeding which would also provide protection against variances between costs and recoveries; these are dealt with elsewhere in this Decision.

The move to IRM from cost of service regulation for hydroelectric payments

Concentric gave the move to IRM as one of the factors that would increase risk for OPG and therefore justify an increase in equity thickness.

In the previous OPG payment amounts decision (EB-2013-0321) the OEB expressly considered whether the move to IRM would increase risk to OPG and found that it did not. There is no new evidence in this case that the hydroelectric IRM will have any impact on risk. There are protections from forecast risk, with respect to costs and hydroelectric production, provided by the Hydroelectric Water Conditions Variance Account, and the CRVA for a significant amount of capital spending on hydroelectric. There are other mechanisms under a Price Cap IR plan such as those approved by the OEB in this Decision including Z-factors and ICMs, as proposed by OPG and available to it under the policies established in the Handbook for Utility Rate Applications (the Rate Handbook) issued after the application was filed. Given these protections, the OEB does not consider the move to IRM to pose much uncertainty for OPG.

The OEB has not changed the capital structure of any of the gas or electric utilities it regulates when they have moved to IRM. The expert witnesses agreed that they were unaware of any increase in risk to, or difficulty accessing capital by, these utilities after moving to IRM.

Capital Expenditures Related to the DRP

There is no question that successful execution of the DRP is a challenge for OPG during the term of this plan. The OEB accepts OPG’s argument and the expert evidence that the impact of capital spending is prospective as it must be financed. The question here is whether the risks posed by the DRP alone justify an increase in the equity thickness.

The experts acknowledged that to date, there is no evidence that OPG has had any difficulty accessing the capital required for this project.

As noted in the section of this Decision on the DRP, OPG’s evidence is that it has undertaken an exceptional level of planning for this project in order to reduce the risks.

More importantly, the risk posed by the DRP must be assessed in the context of the regulatory environment that applies to OPG. The types of risks faced by other regulated entities, such as gas utilities, when embarking on major capital projects do not apply to

OPG. O. Reg. 53/05 provides that the OEB must accept the “need” for the DRP, so there is no risk that the OEB will find in some later proceeding that it was not required and refuse to allow it to be added to rate base. This regulation also provides that OPG will recover its DRP costs not already in payment amounts through the CRVA, so long as they are prudent, even if the units are never returned to service. This is a protection not provided to other utilities the OEB regulates.

The OEB finds that given the planning, the approval of the spending in this proceeding and the regulatory protections afforded OPG, the DRP does not materially increase OPG’s business risk.

Pickering Extended Operations

Concentric suggests that there are risks associated with Pickering Extended Operations, such as a determination that it may not proceed, and the risk of recovery of expenditures incurred in that event. Given the OEB’s decision in this case regarding PEO, these risks are unlikely to materialize. PEO also enjoys many of the same protections as the DRP. PEO enabling expenditures have been approved in this proceeding, and any variances will be recovered through the CRVA.

Revenue deferred under rate smoothing

Rate smoothing is required by O. Reg. 53/05. The OEB finds there is no real risk, as suggested by OPG’s cost of capital witness, that having implemented a rate smoothing plan required by regulation, the OEB would not allow OPG to recover the deferred rates.[132]

OPG and Concentric argued that risk is also increased due to the impact on OPG’s cash flow. However, the OEB notes that OPG has not identified any concerns with it being able to obtain necessary financing for DRP and other operations, nor has it forecasted increased debt costs for capital financing over the period. OPG and the markets are aware of the risks, but are also aware of the protections provided through regulation and through the OEB’s rate-regulatory mechanisms, such as deferral and variance accounts.

In the OEB’s view, the rate smoothing that will ultimately be approved will provide adequate recoveries for OPG to manage its cash flow and other credit metrics during the five-year plan term, and that OPG and its lenders are aware of and are compensated with respect to deferred revenue which will, subject to prudence review,

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[132] Exh C1-1-1 Attachment 1 page 28.

be recoverable in the long run due to the protections afforded by O. Reg. 53/05 and established deferral and variance accounts.

Recovery risk associated with pension and OPEB costs

Pension and OPEB costs are dealt with elsewhere in this Decision. In terms of increasing risk to OPG, the variance account required by the OEB in the previous payment amounts proceeding to track the differences in accounting treatment was established as a placeholder pending the outcome of the OEB's consultation on Pension and OPEB Costs (EB-2015-0040) and, specifically, the application of the eventual policy outcome to OPG. In its report resulting from the EB-2015-0040 consultation, the OEB determined that the accrual accounting method will be the default method on which to set rates for pension and OPEB amounts in cost-based applications, unless that method does not result in just and reasonable rates in the circumstances of any given utility. The report also established the use of a variance account to track the difference between the forecast accrual amount in rates and actual cash payments made, with asymmetric carrying charges in favour of ratepayers applied to the differential. The OEB may make a decision on whether this policy will apply to OPG when OPG proposes disposition of its related variance account. To the extent that there is a risk to OPG that the OEB may find differently for OPG (i.e. that the cash method shall apply), one potential negative outcome that OPG has claimed is that it would be forced to take a significant write-off related to these costs. This matter was not specifically tested in this proceeding and so the OEB has placed little weight on any recovery risk associated with pension and OEPBs.

Further, the OEB notes that parties, including OPG, acknowledged the OEB's policy on the regulatory treatment of pension and OPEB cost recovery in their submissions. SEC's argument notes that, while OPG's cost of capital expert witnesses from Concentric took the position that OPG's risk was increased relative to EB-2013-0321, the impact was immaterial.[133] In its reply argument, OPG notes that: "As noted by OPG in its EB-2015-0040 submission, continued recognition of the amounts recorded in the Pension & OPEB Cash Versus Accrual Differential Deferral Account is dependent on OPG beginning to recover those amounts within five years from the time that they were incurred. For example, amounts recorded during November 2014 must begin to be recovered no later than November 2019 and must be fully recovered within 20 years of November 2014. Failing this, OPG will be required to write off the regulatory asset for these amounts. As such, OPG will be required to file an application to review the

[133] SEC submission page 16.

disposition of the Pension & OPEB Cash Versus Accrual Differential Deferral Account in short order."[134]

The OEB is satisfied that this matter can and will be addressable in a timely manner, and hence that the risks identified by OPG and Concentric do not materially support any increase in risk or equity thickness.

Credit risk

The OEB finds that credit risk is not an independent factor in assessing whether business risk has changed – it is the credit rating agencies' assessment of those risks as to how they may affect solvency and liquidity. A downgrade in credit rating increases the cost of borrowing and may reduce or prevent access to some capital markets.

Both experts agreed that the credit rating agencies would take account of the regulatory protections enjoyed by OPG, as well as the Province of Ontario's ownership in assessing the risk of a project such as the DRP and how it affects OPG's overall credit risk.

Further, based on OPG's history since its incorporation, the credit rating agencies have not made material changes to OPG's credit ratings, with the one downgrade being linked to a downgrade in the Province's credit rating. So far, the credit rating agencies have not altered OPG's rating as a result of the DRP, PEO or any of the other potential risks identified by the witnesses.

OPG's equity ratio in comparison to other utilities selected by each expert

Each of the experts used a comparator group to determine the range of equity thickness that would be appropriate for OPG and to determine where OPG should be in that range.

The OEB accepts that the fair return standard requires that similar utilities be comparable in terms of equity thickness as well as return on equity. However, the jurisdiction in which utilities operate and are regulated is also a factor that must be considered.

While the experts used different comparator groups, both relied heavily on U.S. companies, as there are very few companies in Canada similar to OPG. Concentric included two Canadian utilities, Fortis and Emera, in its comparator group of 20 utilities. The range of equity ratios was 40.27% to 53.94%, the average was 49.06%, and the

[134] Reply Argument page 214.

median was 49.95%. They compared this to OPG at 45% and found that it should at least move to the median of the range. The two Canadian utilities had the lowest equity ratios at 40.27% and 43.31%.

Concentric's report includes a discussion of the fair return standard but focusses mostly on the cost of capital and return on investment rather than equity ratios. Appendix A to the report is a discussion of precedent for Canadian regulators using U.S. data. This discussion deals mostly with ROE, although the British Columbia Utilities Commission appears to have accepted that U.S. natural gas distribution companies have the potential to act as a useful proxy on capital structure in the Terasen Gas (Whistler) Inc. decision (Decision G-158-09). However, a bulletin published by Concentric on May 1, 2015 (Authorized Return on Equity for Canadian and U.S. Gas and Electric Utilities)[135] shows the range common equity ratios for utilities in the U.S. and Canada. This bulletin observes that the allowed ROE in the U.S. and Canadian have converged, but this is not true for common equity ratios as can be seen below:

Table 31: Authorized Common Equity Thicknesses for Canadian and U.S. Gas and Electricity Utilities (2015)

Common Equity Ratio (%)	Canada Range	Canada Average	US Average
Gas	30 – 46.5	40	50.6
Electricity Distributors	25 – 45	38.53	51.81

The report also observes that allowed equity ratios for Canadian electricity transmission companies are 14% lower than their U.S. counterparts.

Brattle used a different approach, separating out investor owned utilities with nuclear generation, the Tennessee Valley Authority which has some nuclear and some hydroelectric generation, and companies with only hydroelectric generation. The only Canadian company on the list is BC Hydro, which has no nuclear. Rather than regulated common equity ratios, Brattle used Book Value Equity Capitalization. The mean and median for the seven investor owned companies with nuclear generation was 47.8%

[135] Exh K18.4 pages 28-31.

and 47.4% respectively. There is no substantive discussion of the different equity ratios for Canadian utilities.

The OEB finds that an adjustment to the comparator group data should have been made by both experts to account for the substantially lower common equity ratios allowed regulated utilities in Canada. While the OEB will not impose a level that is 10% lower than comparable U.S. utilities, at 45%, OPG is already at the top end of the range for all the Canadian utilities for which data was presented, and less than 10% lower than any of the U.S. utilities surveyed.

The OEB considers that based on the evidence in this case, and in combination with all of the cost of capital parameters, and consideration of all of the rate-setting provisions and conditions established previously or approved in this Decision, that on balance an increase in OPG's equity thickness is not necessary in order for the fair return standard to be met.

As the OEB has found that no change in equity thickness is required, the proposed Hydroelectric Capital Structure Variance Account is not required.

6.2 Return on Equity

The application, as originally filed, reflected an ROE of 9.19%, but proposed that for 2017, the ROE would be set using the prevailing ROE specified by the OEB in accordance with the OEB's Cost of Capital Report. The ROE for 2017 was subsequently updated to 8.78% in accordance with the parameters published by the OEB on October 27, 2016. The 2017 ROE of 8.78% was reflected in the impact statement filed by OPG on December 20, 2016.[136] For the years 2018 to 2021 OPG proposed that the OEB specified rate would also apply, but that the revenue requirement impact of any change in ROE would be recorded in a new Nuclear ROE Variance Account.

This application seeks hydroelectric payment amounts set under IRM. OPG did not propose to update the ROE for the regulated hydroelectric facilities.

While OPG's proposed Nuclear ROE Variance Account is inconsistent with the Rate Handbook, OEB staff did not oppose the new account as the application was filed prior to the issuance of the Rate Handbook. CCC, LPMA and SEC also argued that the proposal is inconsistent with the Rate Handbook. SEC further argued that OPG's proposal was contrary to O. Reg. 53/05. The requirement to set revenue requirement on

[136] Exh N1-1-1.

a five-year basis is a clear indication that the OEB should avoid approving deferral and variance accounts to track differences in parts of the revenue requirement. OPG argued that the setting of nuclear revenue requirement on a five-year basis must be interpreted in the context of the regulation as a whole.

Findings

OPG has filed a five-year Custom IR application for nuclear payment amounts. The Custom IR term, and the concept, were first espoused by the OEB in the RRFE Report, applicable to electricity distributors. The Custom IR plan was designed to accommodate individual utilities whose circumstances, particularly with respect to operating and capital needs to serve energy users over a multi-year term were not sufficiently stable and predictable that rate adjustment under an annual inflation-less-productivity formula would be adequate.

With the Rate Handbook issued on October 13, 2016, the various rate-setting options, including Custom IR, were extended to all rate-regulated utilities in Ontario.

As noted in section 8.2 of this Decision, the OEB concurs that OPG's proposed plan for nuclear generation assets fits the Custom IR description. Further, while OPG's application was filed prior to the issuance of the Rate Handbook, the OEB finds that OPG's multi-year proposal largely complies with the policies and expectations for a Custom IR plan as enunciated in the Rate Handbook.

Some utilities in both the natural gas and electricity sectors have proposed multi-year plans to accommodate their individual circumstances over the past decade. The OEB's experiences and decisions on such applications have informed the OEB on its Renewed Regulatory Framework and are reflected in the Rate Handbook issued in 2016. In the Rate Handbook, the OEB stated "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)."[137] The OEB went on to state:

- 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

[137] Handbook for Utility Rate Applications page 25.

> establishment of new deferral or variance accounts should be minimized as part of the Custom IR application.[138] [Emphasis added.]

OPG has not proposed annual rate applications, except for the mid-term review (addressed elsewhere in this Decision). However, the OEB considers the proposed Nuclear ROE Variance Account to be analogous to an annual cost of capital update, and thus inconsistent with the OEB's intentions in the Rate Handbook. Accordingly, the OEB does not approve this proposed variance account.

As noted above, the OEB is disallowing the proposed change in equity thickness. As a result, the OEB is not approving the proposed Hydroelectric Capital Structure Variance Account, and finds that consideration of submissions on the Hydroelectric ROE is not necessary.

6.3 Long-term and Short-term Debt

OPG seeks to recover the costs of long-term and short-term debt associated with its regulated operations during the IR term. The parties to the settlement agreed that the interest rates used to calculate OPG's proposed debt costs were appropriate. Those rates are:

Table 32: Long-Term and Short-Term Debt Rates

	2017	2018	2019	2020	2021
Long-Term Debt	4.89%	4.60%	4.52%	4.49%	4.48%
Short-Term Debt	1.41%	2.73%	3.75%	3.80%	3.65%

Source: Exh C1-1-1, Tables 1-5

While there was agreement on the debt rates, issue 3.2 was only partially settled as the costs for debt components of the capital structure would depend on the OEB's final determination on capital structure and rate base.

Findings

The OEB accepted the settlement proposal with respect to long- and short-term debt rates.

[138] Handbook for Utility Rate Applications page 26.

In argument, LPMA raised an issue about the composition of the debt between short term and long term. OPG's proposal is to maintain a constant amount of short term debt though 2021 ($37.1 million). LPMA argued that the proportions of short and long term debt should be constant, which would result in a larger amount of short term debt as the overall debt increases during the five-year term of the plan.

The OEB agrees with OPG that there is no reason to adjust the level of short term debt. First, the issue was settled by the parties, including LPMA, so there was no discussion of it at the oral portion of the hearing. Argument is not the appropriate time to raise an issue about a matter that appears to be settled. Secondly, the OEB agrees with OPG that there is sufficient evidence on the record to explain the change in the relative proportions of short and long term debt. The level of short term debt is not increasing. The portion of debt that is long term is increasing substantially due to the DRP. The substantial increase in long term debt for the DRP does not impact the need for short term debt for OPG's business operations. There is no reason to require OPG to partially fund the DRP or other capital projects through short- rather than long-term debt solely for the purpose of maintaining a constant ratio that is not aligned with OPG's debt financing requirements during this five-year period, and which is likely to continue beyond 2021.

The final approved debt costs will be adjusted by the rate base and capital structure findings found elsewhere in this Decision.

7 DEFERRAL AND VARIANCE ACCOUNTS

OPG proposed to recover the audited December 31, 2015 balances in deferral and variance accounts, less the 2016 amortization amounts approved in EB-2014-0370, except for the Pension & OPEB Cash Versus Accrual Differential Account and the amounts approved for future recovery in the Pension & OPEB Variance Account in EB-2012-0002 and EB-2014-0370. OPG proposed clearance in riders over two years of $86.8 million for the regulated hydroelectric facilities and $217.9 million for the nuclear facilities. Many of the issues related to deferral and variance accounts were either fully settled or partially settled.

7.1 Additions to Accounts

Issue 9.1 (Is the nature or type of costs recorded in the deferral and variance accounts appropriate?) was partially settled. The nature or type of costs recorded in the CRVA (nuclear), Nuclear Liability Deferral Account and Bruce Lease Net Revenues Variance Account were not settled. There were no submissions filed on this issue in relation to these accounts.

As noted in section 5.11 regarding taxes, OEB staff submitted that variances between forecast and actual SR&ED ITCs could be recorded in the existing Income and Other Tax Variance Account. OPG replied that using this account would be inconsistent with the OEB approved settlement agreement and with the intent of the Income and Other Tax Variance Account. The account was originally established in the EB-2007-0905 decision to record variances due to changes in tax rates or rules, new assessing or administrative practices of tax authorities, and tax re-assessments for past periods. However, OPG did not object to prospectively truing up nuclear SR&ED ITCs using a new SR&ED ITC variance account.

The nature and type of costs recorded in the CRVA (nuclear), Nuclear Liability Deferral Account, Bruce Lease Net Revenues Variance Account and Income and Other Tax Variance Account will be as described in the application. A new SR&ED ITC Variance Account has been approved by the OEB in section 5.11 of this Decision.

Issue 9.2 (Are the methodologies for recording costs in the deferral and variance accounts appropriate?) was partially settled. Similar to issue 9.1, the methodologies for recording costs in the CRVA (nuclear), Nuclear Liability Deferral Account and Bruce Lease Net Revenues Variance Account were not settled. Submissions on the operation of the CRVA were filed by OEB staff, CCC, LPMA and SEC. No submissions were filed on this issue for the other two accounts.

While not identified in the settlement proposal, the methodology for recording costs in the hydroelectric CRVA sub-account was also reviewed in this proceeding. OPG's proposal regarding methodology for recording costs was set out in the application and additional evidence at Exh H1-1-2. Under OPG's proposal, there will be no additions to the CRVA until depreciation escalated by (I – X) is exceeded. The CRVA eligible additions would then be compared with the $0.9 million CRVA amount underpinning current payment amounts. SEC submitted that the threshold should include ROE and cost of debt as well as depreciation. OEB staff submitted that the $0.9 million reference amount should be escalated by (I – X). OPG argued that ROE and cost of debt are not available to fund replacement or new investment, and that there are no prior decisions that require threshold amounts to be escalated by a price cap or (I – X).

Both OEB staff and CCC submitted that additions to the nuclear CRVA sub-account should only occur in circumstances where non-CRVA in-service amounts are not under-spent. OPG disagreed as the Custom IR application, unlike the Hydroelectric IRM application, is underpinned by a five-year capital plan. The specific projects that will be subject to CRVA treatment, e.g. DRP and PEO, are clearly identified and there were no submissions objecting to these CRVA eligible projects. The nuclear CRVA operation in this Custom IR application is no different than that in previous cost of service applications.

The methodologies for recording costs in the Nuclear Liability Deferral Account and Bruce Lease Net Revenues Variance Account will be as described in the application.

As noted in section 8.1 of this Decision, Hydroelectric Payment Amount Setting, the OEB agrees with OPG that SEC's inclusion of the cost of debt, ROE and payments in lieu of taxes (PILs) as "Capital Built into Base Rates" is incorrect. The OEB finds $0.9 million of the CRVA amount underpinning current payment amounts should be adjusted by the hydroelectric IRM inflation less productivity factor (I – X).

As noted in section 5.2 of this Decision, Nuclear Capital Expenditure and Rate Base, the OEB finds that the operation of the nuclear sub-account of the CRVA will continue as proposed by OPG.

7.2 Balances in Accounts and Disposition

Issue 9.3 (Are the balances for recovery in each of the deferral and variance accounts appropriate?) was partially settled. OPG has proposed to recover its audited December 31, 2015 deferral and variance account balances, less certain 2016 amortization amounts. The balances for recovery in the CRVA (nuclear), Nuclear Liability Deferral

Account, Bruce Lease Net Revenues Variance Account and the Pension & OPEB Cash Versus Accrual Differential Deferral Account were not settled. There was only one submission on this matter. OEB staff submitted that the amounts recorded in the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the Pension & OPEB Cash Payment Variance Account will need to be reviewed at the time they are requested for disposition. In reply, OPG argued that the amounts are not subject to prudence review, referring to the EB-2013-0321 decision which states that the differences are not set aside for a future prudence review.

The balances for recovery in the CRVA (nuclear), Nuclear Liability Deferral Account and Bruce Lease Net Revenues Variance Account will be as described in the application.

The OEB finds that since the disposition of the balance in the Pension & OPEB Cash Versus Accrual Differential Deferral Account has not been requested as part of this application, the matter of the scope of the review will be deferred to a future application and addressed at the time disposition of the balance is requested. The OEB also notes that the final Report of the OEB on the Regulatory Treatment of Pension and OPEB Costs (EB-2015-0040) has been issued and expects OPG to address the applicability of the outcomes of the Report to OPG.

Issue 9.4 (Are the proposed disposition amounts appropriate?) was not settled. With the exception of the Pension & OPEB Cash Versus Accrual Differential Account, OPG proposed recovery of the audited December 31, 2015 balances in deferral and variance accounts, less amortization amounts approved in EB-2012-0002 and EB-2014-0370.[139]

The proposed disposition amounts for this proceeding are $86.8 million for regulated hydroelectric facilities and $217.9 million for nuclear facilities. No submissions were filed on this matter.

The OEB approves the disposition of $86.8 million from regulated hydroelectric deferral and variance accounts and $217.9 million from nuclear deferral and variance accounts as proposed by OPG.

Issue 9.5 (Is the disposition methodology appropriate?) was not settled. As in previous proceedings, OPG proposed separate hydroelectric and nuclear payment amount riders. OPG proposed disposition of the amounts noted above over a two-year period commencing January 1, 2017. The production basis for the hydroelectric payment amount rider would be the 2015 actual regulated hydroelectric output. The production

[139] The EB-2012-0002 decision approved a 12-year amortization of the Pension and OPEB Cost Variance Account (Future) and the EB-2014-0370 decision approved a six-year amortization of the Pension and OPEB Cost Variance Account (Post 2012 Additions).

basis for the nuclear payment amount rider would be the proposed 2017-2018 forecast nuclear output.

OEB staff, in its submission on rate smoothing, submitted that the OEB could consider different disposition weightings to smooth payment amounts, e.g. 60% in one year and 40% in the next year. OEB staff also submitted that the OEB could consider riders that are effective on a date other than January 1, 2017, e.g. July 1, 2017.

The OEB is ordering an effective date of June 1, 2017 for the base payment amounts as noted in section 12 of this Decision. OPG shall file a draft payment amounts order reflecting deferral and variance account disposition and a proposal for the recovery period as noted in section 11 of this Decision.

OPG's draft payment amounts order shall include a weighted average payment amount smoothing proposal that includes the deferral and variance account riders.

7.3 Continuation of Accounts and New Accounts

Issue 9.6 (Is the proposed continuation of deferral and variance accounts appropriate?) was settled. The parties agreed to OPG's proposal to continue the accounts described in Exh H1-1-1.

Issue 9.7 (Is the rate smoothing deferral account in respect of the nuclear facilities that OPG proposes to establish consistent with O. Reg. 53/05 and appropriate?) was not settled. In accordance with section 5.5 of O. Reg. 53/05, the Rate Smoothing Deferral Account (RSDA) will be established effective January 1, 2017. The RSDA will record the difference between (1) the total annual nuclear revenue requirement approved by the OEB and (2) the revenue requirement that is used to set the approved nuclear payment amounts in each year.

The deferred amounts will be recorded in the RSDA from January 1, 2017 until the end of DRP. O. Reg. 53/05 stipulates that the account shall record interest at OPG's long term debt rate, compounded. O. Reg. 53/05 requires recovery on a straight line basis at the end of DRP over a period of 10 years or less. Submissions were filed on rate smoothing, but not on establishing the RSDA or its consistency with the regulation.

Both OEB staff and CCC made submissions regarding the CRVA (low interest rate, simple interest) and RSDA (long-term debt rate, compounded interest) operation. OEB staff's submission includes several suggested reductions to OPG's DRP proposal. OEB staff noted that any variances would be tracked in the CRVA and prudent costs dispositioned after 2021. OPG argued that the recovery of these variances would place added pressure on rate smoothing in the 2022 to 2026 period.

CCC observed that, depending on the OEB's decision, there could be significant RSDA additions at the same time that there are credit amounts in the CRVA. CCC submitted that credits to the CRVA should be tracked in the RSDA. OPG disagreed, stating that the time frame considerations for the accounts have required different carrying cost considerations.

The OEB approves the RSDA as set out in section 5.5 of O. Reg. 53/05, and as proposed by OPG. The effective date for the account is January 1, 2017.

The OEB's findings with respect to nuclear operations capital and rate base are in section 5.2 and with respect to OPG's DRP proposal are in section 5.3 of this Decision. The OEB has approved OPG's DRP proposal. The OEB has reviewed CCC's submission and finds that the proposal to track credits to the CRVA in the RSDA is outside the scope and definition of the RSDA as set out in O. Reg. 53/05.

The entries in the CRVA are subject to prudence review on disposition. The entries in the RSDA track previously approved costs for recovery at a later date. The balances in the RSDA are reviewed only for compliance with the terms of the account. There is no prudence review of the spending itself.

Issue 9.8 (Should any newly proposed deferral and variance accounts be approved by the OEB?) was not settled. In its application, OPG proposed four new deferral and variance accounts:

- Rate Smoothing Deferral Account
- Mid-term Nuclear Production Variance Account
- Nuclear ROE Variance Account
- Hydroelectric Capital Structure Variance Account

The RSDA is discussed above. Submissions were filed objecting to the other three accounts. In a general submission on new accounts, OEB staff submitted that OPG should provide a draft accounting order for each new account during the payment amount order process. OPG replied that the information contained in an accounting order has already been provided, but would provide accounting orders if so directed.

The OEB has not approved a mid-term review for production forecast (section 9 of this Decision) and therefore a Mid-term Nuclear Production Variance Account is not required.

In the Capital Structure and Cost of Capital section of this Decision, section 6, the OEB did not approve the Nuclear ROE Variance Account. As the OEB is not approving a change to equity thickness, there is no need to consider the Hydroelectric Capital Structure Variance Account

Although not initially proposed by OPG in its application, the following new deferral and variance accounts have been approved in this proceeding:

- Fitness for Duty Deferral Account (section 5.6 of this Decision)
- SR&ED ITC Variance Account (section 5.11 of this Decision)

The OEB agrees with OEB staff that a draft accounting order should be provided for each new account, i.e. RSDA, Fitness for Duty Variance Account and SR&ED ITC Variance Account, during the payment amount order process.

7.4 Future Deferral and Variance Account Disposition

OPG proposed to file a mid-term production review application in the first quarter of 2019, that would include a request to dispose of applicable audited 2018 year end deferral and variance account balances.

LPMA submitted that OPG should dispose of deferral and variance account balances annually. This would reduce the potential for large balances and minimize intergenerational inequity. LPMA noted that annual disposition would be consistent with the five year IRM plans of Union Gas and Enbridge Gas Distribution.

On May 18, 2017, the OEB issued its EB-2015-0040 report on *Regulatory Treatment of Pension and Other Post-Employment Benefits (OPEBs) Costs.* The report established the accrual method as the default rate-setting method to recover approved pension and OPEB costs subject to the OEB finding in any particular case that it leads to just and reasonable rates. In its submission, OEB staff submitted that there are implementation matters regarding disposition of deferral and variance accounts and the consideration of the transition to accrual. In its reply argument, OPG submitted that it would be appropriate to clear the Pension & OPEB Cash Versus Accrual Differential Deferral Account at the same time as its application for 2018 hydroelectric payment amounts. OPG repeated its submission from the EB-2015-0040 proceeding which noted that under the requirements of USGAAP, the period of deferring amounts recorded in the Pension & OPEB Cash Versus Accrual Differential Deferral Account must not exceed five years from the time that they were incurred. For example, amounts recorded during November 2014 must begin to be recovered no later than November 2019 and must be fully recovered within 20 years of November 2014. Failing this, OPG will be required to write off the regulatory asset for these amounts. As such, OPG will be required to file an application to review the disposition of the Pension & OPEB Cash Versus Accrual Differential Deferral Account in short order.

The OEB has not approved a mid-term review for production forecast. OPG may file to dispose of applicable audited deferral and variance account balances at the same time as its application for 2019 hydroelectric payment amounts in calendar year 2018. OPG may include its proposal for review of the Pension & OPEB Cash Versus Accrual Differential Deferral Account.

8 METHODOLOGIES FOR SETTING PAYMENT AMOUNTS

Section 6(1) of O. Reg. 53/05 provides that the OEB may establish the form, methodology, assumptions and calculations used in making an order that sets payment amounts. Since 2008, the payment amounts for the nuclear and regulated hydroelectric business have been set on a cost of service basis. However, the OEB indicated its intention to implement an incentive regulation formula for OPG prior to the first payment amount proceeding.[140] The 2011-2012 payment amount decision[141] concluded that incentive regulation for OPG should begin in 2015 and directed OPG to provide a work plan and status report for an independent productivity study with the next cost of service proceeding.

OEB staff commissioned Power Advisory LLC to prepare a report on incentive regulation options for OPG, and conducted a stakeholder consultation in 2012. Following the consultation, the OEB issued a report in 2013 under file EB-2012-0340 setting out the OEB's policy direction associated with implementing incentive regulation for OPG.[142] With the completion of the Niagara Tunnel Project, the regulated hydroelectric business would more closely resemble steady state. The OEB concluded that following completion of one further cost of service application, an IR mechanism should be used to set payment amounts for the regulated hydroelectric business. As large capital expenditure for the nuclear business was forecast along with reduced production forecast related to DRP and Pickering closure, the OEB concluded that a longer term cost based approach should be explored for the setting of nuclear payment amounts. These approaches were again confirmed by the OEB in the 2014-2015 payment amount decision.[143]

The OEB informed interested parties on February 17, 2015 that it would not establish working groups on incentive rate-setting (IR) mechanisms as OPG had already initiated stakeholder consultations. The OEB advised of its expectations of an IR framework for the regulated hydroelectric business and a custom IR framework for the nuclear business.

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[140] Board Report, *A Regulatory Methodology for Setting Payment Amounts for the Prescribed Generation Assets of Ontario Power Generation Inc.,* EB-2006-0064, November 30, 2006.
[141] EB-2010-0008 March 10, 2011.
[142] Report of the Board, *Incentive Rate-making for Ontario Power Generation's Prescribed Generation Assets,* EB-2012-0340, March 28, 2013.
[143] EB-2013-0321 November 20, 2014.

8.1 Hydroelectric Payment Amount Setting

8.1.1 Application for Price Cap IR

OPG has proposed a price cap IR methodology for the regulated hydroelectric business that is similar to the price cap IR methodology used by electricity and gas distributors. This methodology was previously known as 4th generation IR.

$$\text{Payment Amount(t)} = \text{Payment Amount(t-1)} \times \left(1 + \text{Inflation Factor} - (\text{Productivity Factor} + \text{Stretch Factor})\right)$$

OPG seeks approval of the payment amount setting formula for the five-year period 2017 to 2021. OPG also seeks approval for the regulated hydroelectric payment amount of $41.71/MWh effective January 1, 2017. The starting point for the payments amounts are those approved in EB-2013-0321. OPG proposed an inflation factor of 1.8% for 2017, a productivity factor of zero and a stretch factor of 0.3%, as well as other features of IR plans, e.g. Z-factor treatment for unforeseen events.

OPG proposes to file an application in the fall of each year to set the next year's payment amounts. Adjustments would be mechanistic and based on the determination of an updated inflation factor.

There were no submissions filed that opposed the overall price cap IR methodology. However, there were submissions on the inflation, productivity and stretch factors. The Society and PWU supported all aspects of OPG's application with respect to hydroelectric payment amounts. Sustainability-Journal submitted that OPG should make more use of available flow from the hydroelectric generation stations.

Findings

The OEB agrees with the overall approach of an annual mechanistic update as it accords with the approach used by electricity distributors and the *Handbook for Utility Rate Applications*.

Each of the factors is discussed further in the Decision below. As noted below, the OEB has already accepted the base payment amount of $41.09/MWh by approving the settlement proposal.

8.1.2 Base Hydroelectric Payment Amounts

OPG proposed to use the hydroelectric payment amounts approved in EB-2013-0321, adjusted for a tax allocation, as the going-in payment amounts for the IR term. The hydroelectric payment amounts include a one-time allocation of nuclear tax losses relating to the EB-2013-0321 proceeding. Parties to the settlement proposal agreed with the adjustment for the tax allocation and the resulting going-in hydroelectric payment amount of $41.09/MWh. This was accepted by the OEB on March 20, 2017.

8.1.3 Inflation Factor

Inflation Factor Components

OPG retained London Economics International LLC (LEI) to recommend an appropriate inflation factor. A composite index based on the following Statistics Canada indices was recommended:

- Canadian Gross Domestic Product Implicit Price Index – Final Domestic Demand (GDP-IPI FDD)
- Average Weekly Earnings for Ontario – Industrial Aggregate (Ontario AWE) Canada.

The OEB uses the same indices to determine the inflation factor for electricity distributors, and has done so since 2013. The weightings used for electricity distributors are 30% for labour and 70% for non-labour.[144] LEI determined that the appropriate weighting for the capital intensive hydroelectric generating industry is 81% for capital, 7% for non-labour OM&A and 12% for OM&A labour (i.e. 88% non-labour, 12% labour).

There were no submissions filed opposing the recommended indices or the recommended weightings, except for the submissions on the Gross Revenue Charge (see section below).

Findings

The OEB accepts the indices and weightings as proposed. The OEB's findings with respect to the Gross Revenue Charge are discussed below.

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[144] Report of the Board on *Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors* (EB-2010-0379) November 21, 2013.

Inflation Factor Calculation

Through interrogatories and cross-examination, OEB staff reviewed OPG's calculation for its proposed inflation factor for 2017. OEB staff submitted that, consistent with the OEB's practice since 2013, the arithmetic approach to calculate annual growth rate should be replaced with the natural log function, and further that any rounding of data should not be done in intermediate step calculations. OEB staff noted that the change to the natural log function was not apparent in the documentation issued in 2013.

While OPG had calculated a 1.8% inflation factor for 2017, OEB staff submitted that the correct calculation method would result in an inflation factor of 1.7%. In reply argument, OPG accepted OEB staff's proposed methodology for calculating the I-factor.

Findings

The OEB agrees that the natural log function should be used to calculate the annual growth rate as it is consistent with OEB practice established since 2013. This approach and rounding of data as a final step will be used for 2017. The same methodology is to be used in future years.

Gross Revenue Charge

Several parties questioned whether the I-factor should apply to the Gross Revenue Charge (GRC) component of hydroelectric revenue requirement. As noted in Exh F1-4-1 of the EB-2013-0321 application, the forecast GRC for the regulated hydroelectric facilities was $328.9 million and $347.1 million in 2014 and 2015, respectively.

SEC argued that the I-factor should give 0% weighting to the GRC as it is a fixed charge based on production and does not vary with inflation, and this is not expected to change in the test period. SEC estimated the GRC to be 25% of hydroelectric revenue requirement.

While LEI testified that GRC was similar to PILs, SEC argued that PILs will increase with inflation as the revenues and expenses underpinning net income, on which PILs are applied, are expected to increase with inflation. SEC calculated a GRC adjusted inflation factor of 1.35% for 2017. OEB staff submitted that some portion of inflation-less costs is factored into GDP-IPI, and proposed that half of the GRC be considered as inflation-less, resulting in a GRC adjusted inflation factor of 1.5%. CCC and LPMA proposed Y-factor treatment for GRC.

OPG replied that the GRC is not meaningfully different from other taxes in revenue requirement. There is no principled basis on which to carve out the GRC.

Findings

The OEB has considered the SEC submission that the inflation factor should not apply to GRC, and the OEB staff submission that a portion of the GRC could be excluded from inflation treatment.

Section 92.1(4) of the *Electricity Act, 1998* provides that the GRC tax component is a percentage of gross revenue from annual generation. Section 92.1(5) also sets out the rates for the GRC water rental component as a percentage of gross revenue from annual generation. Accordingly, the entire GRC is determined on the basis of gross revenue from annual generation and not on production as submitted by SEC. Under IRM, the gross revenue which is underpinned by hydroelectric payment amounts will reflect some level of inflation, and therefore the tax and water rental components of the GRC will reflect similar levels of inflation as OPG's other costs and those of businesses in other sectors of the economy. This inflation in business costs is measured in macroeconomic price indices like the GDP-IPI.

The OEB finds that it is appropriate to apply the I – X factor to the GRC.

8.1.4 Productivity Factor

The OEB and the electricity distributors are experienced with the index method which converts outputs and inputs into an index value for the determination of industry total factor productivity (TFP). There is no precedent for TFP studies of the hydroelectric generation industry for the purposes of ratemaking.

As directed by the OEB in the 2011-2012 payment amounts decision, OPG contracted with LEI in 2013 to conduct an independent productivity study of the hydroelectric generation industry. The report summarizing that work was filed with the OEB on December 18, 2014. The report was subsequently updated and filed in this proceeding. Based on an analysis of OPG and 15 US peers using data from 2002-2014, LEI calculated an estimated annual TFP of -1.01%. LEI explained that a negative TFP should be expected for the mature hydroelectric generation industry as there is increasing OM&A, relatively constant capital and relatively stable output. In the application, OPG proposed a 0% productivity factor, noting that the OEB has declined to accept negative productivity for electricity distributors.

OEB staff retained Pacific Economics Group Research LLC (PEG) to review OPG's hydroelectric IRM proposal, LEI's TFP study, and to conduct an independent study.

PEG's analysis and its determination that a TFP of 0.29% is appropriate was filed as evidence in the proceeding.[145]

Representatives of both LEI and PEG appeared as expert witnesses at the oral hearing. OPG and the unions urged the OEB to accept LEI's analysis, while OEB staff and the other intervenors argued in favour of PEG's analysis.

The following table summarizes the TFP methodologies and results:

Table 33: LEI and PEG Productivity Factor Methodologies and Results

	LEI	PEG
Output	Generation (MWh)	Capacity (MW)
Inputs	Operating Cost	Operating Cost
	Capital Measure (MW – physical) No depreciation assumed	Capital Measure (monetary) depreciation based on geometric decay, return on rate base, taxes
Sample	US utilities and OPG (16 total)	US utilities (21 total)
Period	2002 to 2014	1996 to 2014
Total Factor Productivity	-1.01%	0.29%

LEI selected plant capacity as the capital input measure. Capacity data are readily available and consistently measured in the industry. Further, assuming proper maintenance, productive capacity does not generally depreciate or decline significantly over time. OPG's Reply Argument states that LEI's approach does not require the OEB to make any assumptions about depreciation of hydroelectric assets.

PEG chose geometric decay to model depreciation for the capital input measure based on monetary data of hydroelectric assets. Geometric decay is widely used in North America and has been used by PEG for most of the research it has completed in the past for the OEB. It is PEG's view that hydroelectric assets do not exhibit a constant flow of service throughout their lives.[146] There is a decline in the flow of service as measured by a continual stream of "refurbishment" capital to maintain productive capacity. Further, individual assets have components with different service lives.

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[145] Exh M2.
[146] PEG response to LEI memorandum, February 16, 2017.

OPG argued that PEG's use of the geometric decay profile is primarily responsible for the positive TFP identified. OPG states that the use of geometric decay contradicts references cited by PEG, namely an Organization of Economic Cooperation and Development manual, which suggests that bridges and dams are examples of assets that show no (or little) functional depreciation until end-of-life.

Whether water availability was correctly or adequately reflected in the analysis was central to examination of and submissions on TFP output measures. OPG stated that generation is a superior output measure as this is how OPG is paid and hydroelectric and efficiency improvements generally increase generation. However, PEG and several parties observed that generation is sensitive to weather fluctuations and hydrology, and therefore choice of the sample period as well. While PEG selected capacity as the appropriate output measure citing its stable growth and the importance of MW as a cost driver, OPG argued that it would incent a utility to build excess capacity despite lacking water to use the capacity.

There were differing views on which methodology best reflected the impact of the Niagara Tunnel Project which cost $1.5 billion and increased generation by 1.5 TWh. LEI's methodology captures the increased MWh impact, while PEG's methodology captures the expense.

In reply argument, OPG stated that the matter before the OEB is not which TFP methodology to apply, rather the issue is whether OPG`s proposed 0% productivity factor is appropriate.

Findings

While there have been TFP based empirical studies for generation in academia, the LEI and PEG TFP studies are the first TFP studies for the hydroelectric generation business sector for the purposes of regulatory ratemaking.[147] The OEB is not prepared to completely accept the approach of either expert. As discussed extensively in responses to interrogatories, during the oral hearing, and in submissions, there are strengths and weaknesses of both approaches.

The OEB agrees with LEI that generation (MWh) is the most appropriate measure of output, as it is generation produced, and not capacity, which is the basis for revenues to recover capital and operating costs. However, the OEB also recognizes limitations with LEI's approach. The OEB questions LEI's physical approach which uses MW capacity as an input, as this measure does not take into account financial considerations, such

[147] Exh A1-3-2, Attachment 1 Footnote 3.

as the capital costs. Although many hydroelectric generation assets have very long useful lives, the OEB is not convinced that there is no functional depreciation until end of life. In fact, reviews of capital projects to sustain, refurbish and replace hydroelectric stations and assets in OPG's prior payment amount applications confirm that capital expenditures and operating costs are needed to maintain capacity to the end of a station's life. Absent ongoing capital and operating expenditures, hydroelectric generation assets will depreciate over time. In the OEB's view, LEI's physical method, which assumes no depreciation until the end of life, is not a realistic basis for the analysis of productivity of hydroelectric generation facilities.[148]

However, the OEB is also not persuaded that PEG's approach using MW as the output measure is appropriate. MW as an output does not seem reasonable as an underutilized asset will still be considered to be productive. How many MWh can be produced from a plant of a particular MW capacity must bear some relationship to productivity, as, for example, improvements in maintenance (e.g. shorter down time) may result in more output from a plant of the same capacity.

In OPG's situation, the major capital investment in the Niagara Tunnel is intended to result in greater production even if the capacity of the Sir Adam Beck plants is not increased. However, at the same time, there are also factors, such as water availability, which are beyond the control of the plant operator. Not all hydroelectric generation is used as base load, so output may also be reduced due to market conditions.

However, PEG's financial approach, which does take into account depreciation of assets in some form, is in the OEB's view more realistic than LEI's approach, although the OEB observes that there is no consensus on the best method for accounting for economic and physical depreciation or deterioration of assets in these types of analyses.

The OEB also has other reservations about aspects of both LEI's and PEG's studies. Neither study included Canadian generators other than OPG. The OEB accepts that Canadian data was difficult to obtain, but is concerned about the reliance solely on OPG's own and U.S. based generators' data. The OEB notes that neither study provided evidence on how the regulatory environment may influence the production of a hydroelectric generator in a particular jurisdiction. Improved sample, data and

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[148] The OEB made similar findings about LEI's physical approach assuming no economic depreciation of assets with respect to analyses conducted by LEI in the process to develop the 3rd Generation IRM for electricity distributors. See "Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors," EB-2007-0373, September 17, 2008, pages 7-8 and 11-12.

consideration of business and regulatory factors that influence a generator's operations and production would improve the usefulness of the results of studies.

Energy Probe submitted that, while neither expert identified a historical trend in TFP growth, the PEG estimate was superior. Energy Probe's submission and analysis referred extensively to its note on data aggregation which was appended as three appendices to its final submission. Little of this was reviewed in detail with any of the witnesses, nor did Energy Probe provide its own witness. The OEB does not find this information to be helpful.

Given the limitations of the samples, the data and the econometric approaches described above, the OEB finds that, at this time, it cannot accept either LEI's or PEG's analysis in its entirety. Given that these studies suggest a range from 0.29% to -1.01%, the OEB finds that a base productivity factor of 0%, as proposed by OPG, is appropriate for OPG's hydroelectric IRM plan.

The OEB expects that OPG and other stakeholders will take into account the OEB's concerns about the approaches and limitations of the experts' analyses on the record in this proceeding. Improvements in methodology and data, and translation of the results of the studies as to how they more directly translate to rate-setting would provide more useful and convincing information on which OPG could make its next proposal and the OEB would make its determination for subsequent IRM plans.

8.1.5 Stretch Factor

In the EB-2013-0321 decision, the OEB found the hydroelectric benchmarking to be inadequate and ordered OPG to complete a fully independent benchmarking study of hydroelectric operations. The decision stated that the benchmarking should be comparable to the benchmarking in place for the nuclear operations. The decision also stated that the results of the hydroelectric benchmarking study would be important in developing the IR methodology for OPG.

OPG retained Navigant Consulting Inc. (Navigant) to benchmark the hydroelectric operations. The analysis of 2013 performance was filed with the application. OPG's cost and reliability performance are shown in the table below:

Table 34: Navigant Benchmarking Results for
OPG Regulated Hydroelectric Facilities

	Cost Performance Metrics (USD)									Reliability Metrics	
	Operations (K$/Unit)	Plant Maint. ($/MWh)	WW&D Maint. (K$/MW)	B&G Maint. (K$/MW)	Support (K$/MW)	Partial Function ($/MWh)	PA&R (K$/MW)	Total Function ($/MWh)	Invest-ment (K$/MW)	Avail-ability Factor (%)	Forced Outage Rate (%)
OPG Reg. Hydro	$87	$1.41	$1.2	$1.9	$11.8	$5.01	$40	$13.19	$17	92.8	1.3

Q1
Q2
Q3
Q4

WW&D: Waterways & Dams, B&G: Buildings & Grounds, PA&R: Public Affairs & Regulatory

The partial function cost metric is considered by Navigant to be the key cost metric for benchmarking purposes because it includes the functions that are regularly performed at all hydroelectric plants. On this basis, OPG seeks to use a 0.3% stretch factor, and proposes to retain the same stretch factor for the entire test period.

The total function cost includes partial function cost and public affairs and regulatory costs (PA&R). Navigant states that PA&R "is largely not controllable, and in OPG's case is dominated by the Gross Revenue Charges In lieu of Property Tax ($204 million) and the Gross Revenue Charges for water rental fees ($121 million)."[149]

None of the parties opposed the 0.3% stretch factor. OEB staff submitted that there was minimal explanation provided for costs that were excluded and for the benchmarking methodology and that the OEB should set higher expectations for future benchmarking. LPMA noted that there is no process in place to undertake an annual benchmarking exercise to adjust the X-factor each year. LMPA suggested the OEB consider an annual benchmarking exercise for OPG so that the stretch factor could change each year during the IRM.

Findings

OPG's performance with respect to the reliability metrics and the partial function cost metric is second quartile. The OEB accepts that a stretch factor of 0.3% is appropriate for this first hydroelectric IRM term. The OEB does not expect annual benchmarking during the IRM term; however, the OEB expects improved benchmarking going forward. While the Navigant analysis is an improvement over previous filings, the OEB expects some trend reporting and trend analysis in future benchmarking. The OEB also expects

[149] Exh A1-3-2 Attachment 2 page 4.

OPG to continue to examine whether additional costs should be benchmarked for the purposes of future stretch factors. OPG shall file a benchmarking study with its next cost based payment amount application.

8.1.6 Capital Expenditure and Rate Base Issues

OPG has proposed a price cap IR with comprehensive coverage, i.e. capital and OM&A. There was considerable discussion during the oral hearing about the operation of the Capacity Refurbishment Variance Account (CRVA) under price cap IR, and whether there might be double counting.

The CRVA was established to give effect to section 6(2)4 of O. Reg. 53/05, which requires the OEB to ensure that OPG recovers costs incurred to increase the output of, refurbish or add operating capacity to a generation facility. The CRVA was first established for the interim period (i.e. April 1, 2005 to the date of the OEB's first ever payment amounts order) to record the costs to increase output of, refurbish or add capacity. In the EB-2007-0905 decision, the OEB approved the continuation of the CRVA to record cost variances associated with projects that satisfy the requirements of section 6(2)4 of O. Reg. 53/05. The OEB has approved the continuation of the CRVA in subsequent cost of service proceedings.

In response to an SEC interrogatory,[150] OPG provided information relating to hydroelectric projects and amounts that are expected to be recorded in the CRVA during the test period. Approximately 35% of proposed test period capital is CRVA eligible.

PEG gave opinion evidence on the operation of the CRVA for hydroelectric projects. PEG's opinion is that the OEB should not allow OPG to use the CRVA, and require that supplemental capital costs be addressed through incremental capital modules.[151] If the OEB approves the CRVA as proposed, PEG's opinion is that an increase in the X-factor (i.e. productivity factor plus stretch factor) is warranted. PEG estimated this would mean an increase from 0.29 to 0.74.[152] CME and LPMA submitted that the appropriate X-factor is 0.74.

During the oral hearing, the OEB directed OPG to file additional evidence to explain the operation of the CRVA as it relates to hydroelectric operations during the test period. OPG filed Exh H1-1-2 on April 4, 2017. The evidence set out the capital related revenue requirement (sustaining and CRVA eligible) underpinning the current hydroelectric

[150] Exh L-11.1-SEC-95.
[151] Exh M2 page 6.
[152] Tr Vol 11 page 26.

payment amounts. Under OPG's proposal, there will be no additions to the CRVA until depreciation escalated by I-X is exceeded. The CRVA eligible additions would then be compared with the $0.9 million CRVA amount underpinning current payment amounts.

SEC submitted that the threshold should include ROE and cost of debt as well as depreciation. OEB staff submitted that the $0.9 million reference amount should be escalated by I-X.

Findings

The CRVA was designed for and implemented when OPG's payment amounts were determined through a more traditional cost of service regime, where detailed actual and forecasted costs and revenues were considered. This same approach continues through the multi-year nuclear plan. However, as approved elsewhere in this Decision, hydroelectric payment amounts will now be set through a price cap IRM approach under which revenues recovered through payment amounts are not directly linked to costs.

Nevertheless, section 6(2)4 of O. Reg. 53/05, requires the continuation of the CRVA regardless of the form of rate-setting approved or adopted by the OEB. The primary issue then is to address how the CRVA will operate under the hydroelectric IRM plan.

To date, the CRVA has been designed and executed so as to ensure that OPG recovers the full amount of prudently incurred qualifying costs through approved payment amounts. If there is any shortfall (over-recovery), rate riders are used to recover (refund) the incremental amount. For prudently incurred costs of qualifying capital and operating costs, OPG is held whole, as required by O. Reg. 53/05.

In the EB-2013-0321 decision, the approved hydroelectric revenue requirement included an annual amount of $0.9 million for CRVA-qualifying capital projects. This amount is recovered through the approved 2014-15 payment amounts which, with one adjustment as discussed elsewhere in this Decision, are the going-in rates for OPG's Price Cap IR plan. The $0.9 million thus represents the revenue requirement for CRVA-qualifying projects already recovered through payment amounts and which does not need to be recovered again through the CRVA.

The OEB finds that this threshold should be adjusted by the hydroelectric IRM inflation less productivity factor (I – X), which adjusts the payment amounts. As there is no change to the hydroelectric production forecast from the 2014-15 payment amounts approved in EB-2013-0321, the revenue requirement is similarly adjusted. This allows for inflationary cost increases, less expected productivity improvements, to be factored in to the approved rates over time. These inflationary less productivity factors relate to both capital and operating costs. The price cap adjustment is also applied uniformly to capital projects that qualify for CRVA treatment, and those that do not.

In the OEB's view, price cap-adjusted payment amounts recover a similarly adjusted revenue requirement amount each year. The CRVA will recover, through the rate riders approved at the time of disposition, that revenue requirement on qualifying projects not already recovered through approved payment amounts.

OPG submitted that it was not aware of any decisions that require threshold amounts to be escalated by a price cap (or I – X) index. While there may not be any explicit findings in OEB decisions, in the *Report of the OEB on New Policy Options for the Funding of Capital Investments: Supplemental Report* (EB-2014-0219), issued January 22, 2016, the OEB revised the methodology for the materiality threshold applicable to Incremental Capital Module and Advanced Capital Module applications to take into account both the impacts of IRM rate adjustments, and growth in customers and demand, over time. This methodology for multi-year materiality thresholds has been applied by the OEB in ACM and ICM decisions subsequent to this report.

The OEB agrees with OEB staff and intervenors that the CRVA under the hydroelectric IRM plan is similar in many ways to the ACM/ICM, so the OEB's policy on the latter provides a useful precedent.

The adjustment of the threshold for the I – X annual price cap adjustment is largely mechanistic once the Input Price Index is announced each year. While the impact may be small on the threshold based on the payment amounts approved in EB-2013-0321, the OEB notes that the CRVA qualifying capital expenditures are significant, amounting to $335 million or 35% of OPG's forecasted hydroelectric capital additions over the five-year term.

The OEB accepts OPG's proposal with respect to the threshold for the ratio of sustaining capital to CRVA-related capital used to evaluate eligibility for disposition of hydroelectric CRVA balances. The OEB agrees with OPG that SEC's inclusion of the cost of debt, ROE and PILs as "Capital Built into Base Rates" is incorrect.[153] The cost of debt and the ROE are financing costs that OPG must pay out to, respectively, lenders and shareholders (or reinvest to further increase shareholders' equity in the case of the latter) for the investments in hydroelectric capital assets. Taxes and PILs are an

[153] SEC submission pages 126-127 and Exh K21.1 page 15.

expense. These costs are part of the revenue requirement, but not of rate base as SEC argues, and they are not available to fund replacement or new investment except in the case of retained earnings.

8.1.7 Other Elements

OPG's application states that it is eligible to apply for an Incremental Capital Module (ICM) during the term of this hydroelectric IRM plan, and that it is permitted to use an Advanced Capital Module (ACM) in subsequent applications.[154] The OEB's policy on unforeseen events and Z-factor applications will apply during 2017-2021 term.

The submissions of parties focused on the threshold for Z-factor applications. OPG's proposal was $10 million which is the materiality threshold that OPG has applied in each application for impact statements and accounting orders. LPMA submitted that the threshold should be updated to $12.7 million for the hydroelectric business, while CCC submitted that as OPG is an integrated company, the corporate threshold should be $25 million. OPG replied that the materiality ceiling for distributors is $1 million.

OPG proposes to continue all existing hydroelectric deferral and variance accounts. Parties to the settlement proposal, which was accepted by the OEB on March 20, 2017, agreed to fully settle issue 9.6, "Is the proposed continuation of deferral and variance accounts appropriate?"

Annual reporting for the regulated hydroelectric business is addressed in section 10.2.

As noted in the application, OPG proposes that a regulatory review may be initiated if OPG's annual reporting shows performance outside the ± 300 basis points ROE dead band, or if performance erodes to unacceptable measures.

Findings

The ICM and ACM are part of the established Price Cap IR methodology. The Rate Handbook notes that the ACM/ICM approach is also applicable to all rate-regulated utilities under the OEB's oversight.[155] The OEB notes that OPG has not rebased hydroelectric payments in this application, and it has not filed a capital plan, analogous to a Distribution System Plan that an electricity distributor must provide, in this

[154] Exh A1-3-2 page 22.
[155] Handbook for Utility Rate Applications Appendix 3: Rate-setting Policies. Page 27 notes that the ACM/ICM approaches or analogous approaches would be available to all rate-regulated utilities under a price cap IR or similar rate adjustment mechanism, but would not be available under a Custom IR plan.

application or previously. There is no reason not to allow applications for ICMs if they comply with OEB policy during the term of this hydroelectric IRM plan.

LPMA has proposed higher and different thresholds for the hydroelectric and nuclear businesses, however, the OEB finds that this proposal could create confusion. The current OPG $10 million threshold is significantly higher than the highest threshold applied for distributors. The OEB finds that the $10 million threshold will continue to apply for all matters, except for the filing of project business cases where the threshold is $20 million.

The OEB accepts the proposal that a regulatory review may be initiated if OPG's ROE reporting for the regulated business indicates performance ± 300 basis points. This provision is consistent with the RRF and was not opposed by any of the parties.

8.1.8 2017 and 2018 Hydroelectric Payment Amounts

In accordance with the Order section below, OPG shall file a draft payment amounts order reflecting the hydroelectric payment amount setting determinations in this Decision for both 2017 and 2018 based on the applicable parameters.

The calculations for the IPI for OPG's hydroelectric payment amounts per the methodology approved by the OEB are provided in Schedule H to this Decision.

8.2 Nuclear Payment Amount Setting

8.2.1 Application for Custom IR

The OEB established the Custom IR framework for utilities with significant operating and capital expenditures needs. OPG proposed a Custom IR framework for 2017-2021 for the nuclear business. The proposal is based on five individual revenue requirements with 0.3% stretch reductions on base and allocated corporate support OM&A. OPG states that these reductions are in addition to the performance improvement initiatives in its business plan. OPG's proposal was informed by several sources, including the OEB's EB-2012-0340 report, the Renewed Regulatory Framework for Electricity principles, the OEB's letter of February 17, 2015 and O. Reg. 53/05. The regulation was amended in November 2015, requiring the OEB to approve revenue requirements on a five year basis for the first 10 years of the period beginning on January 1, 2017 and ending when the DRP ends.[156]

OPG states that its Custom IR proposal is consistent with the policy objectives of the RRF and that the proposal recognizes the uncertainty and risk related to Pickering and Darlington operation in the test period. The application at Exh A1-3-2 summarizes the proposed Custom IR framework with respect to the RRFE. OPG's proposal was supported by the PWU.

Several intervenors submitted that OPG's proposal is a five-year cost of service application and not a Custom IR as it lacks trade-offs between OM&A and capital and is not based on outcomes. The intervenors submitted that the proposal does not sufficiently consider the principles of the RRF and the considerations for Custom IR applications set out in the Rate Handbook issued by the OEB on October 13, 2016.

OPG argued that its proposal is based on a challenging business plan and that the stretch reductions decouple rates from costs. Unlike distributors, OPG's payment amounts are 100% variable which incents OPG to operate efficiently. As the application was filed in May 2016, OPG also argued that it is inappropriate to apply new Rate Handbook requirements.

LPMA submitted that the costs associated with DRP and PEO should be dealt with separately and on a cost of service basis. LPMA's proposal was raised for the first time in the argument phase and OPG states that the proposal should be rejected.

Findings

As noted previously, the OEB has been considering some form of IR for OPG nuclear payment amounts since 2006. The EB-2012-0340 consultation concluded that alternatives to the short term cost of service approach should be used for setting nuclear payment amounts. The letter of February 17, 2015 stated the OEB's expectation of a Custom IR framework for the nuclear assets.

While the OEB sets and approves the form and methodology for setting nuclear payment amounts, this must be done in accordance with the requirements of O. Reg. 53/05. The OEB finds that OPG's Custom IR application moves the determination of nuclear payment amount along the spectrum from a pure cost-based review as is done in traditional cost of service applications towards an outcomes- and results-based review considered by the RRF. There is no threshold test for Custom IR applications, however, and the OEB has considered and decided on many variations of multi-year

[156] Section 6(2)12(ii) of O. Reg. 53/05.

applications by utilities in both electricity and natural gas; such applications must also take into account the circumstances unique to the utility in each case.

The OEB agrees with OEB staff that OPG has generally met the standards for a Custom IR application as set out in the Rate Handbook that was issued after the application was filed. The OEB finds that OPG was informed by prior applications and decisions, and also took into account the OEB's expectations in prior payment amounts decisions and in the March 28, 2013 report[157] and the subsequent letter from the OEB issued on February 17, 2015[158] in developing its proposed hydroelectric and nuclear payment amounts plans. The OEB also notes that the Rate Handbook is an articulation of policy; as such, it is meant to inform the industry and stakeholders of expectations and to explain the lens through which a review of cost based applications will be accomplished. Indeed, the policies in the Rate Handbook inform the OEB panel deciding an application, and the panel decides on whether the application has sufficiently adhered to the principles and spirit of a policy based on the evidence before it.

OPG provided a five-year forecast of operating and capital costs and production. OPG has proposed productivity gains beyond those that it states are already embedded in its business plan. Several independent benchmarking studies, which are integral to a Custom IR application, were filed and tested during the proceeding. The OEB notes that empirical evidence was one of the key ingredients for a complete Custom IR application discussed in the Rate Handbook.

As the Rate Handbook was issued after the EB-2016-0152 application was filed, certain filing expectations were not specifically addressed by OPG in its application, including trade-offs between OM&A and capital. However, taken in aggregate, the OEB finds that OPG has reasonably satisfied the expectations for a Custom IR plan for setting nuclear payment amounts.

OPG does not have a direct relationship with electricity customers as it sells electricity into the IESO controlled market. The application states that OPG intends to develop a formal customer engagement process during the IR period that may provide insight into customers' preferences with respect to OPG priorities and plans. The OEB expects that process to inform OPG's next application.

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[157] Report of the Board: *Incentive Rate-making for Ontario Power Generation's Prescribed Generation Assets* (EB-2012-0340), March 28, 2013.
[158] OEB-issued letter of February 17, 2015 regarding Incentive Rate-setting for Ontario Power Generation's Prescribed Generation Assets.

8.2.2 X-Factor

OPG's Custom IR X-factor only includes a stretch factor. OPG did not propose a nuclear industry productivity adjustment. OPG states that the nature and scale of capital work planned for the test period meant that past productivity trends would not be a reasonable indicator of predicted productivity.[159] No submissions were filed expressing concern with the lack of an industry productivity factor.

The application proposes a stretch factor of 0.3% on base and allocated corporate support OM&A. The estimated impact is a $50 million reduction in test period revenue requirement. The proposed stretch factor was based on the results of the 2015 nuclear benchmarking report. The 2012-2014 three year rolling average Total Generating Cost (TGC) result for Darlington was first quartile and for Pickering was fourth quartile. These results were based on a comparison of facilities for both major operators (i.e. operating more than one facility) and single facility operators. OPG assumed a 0% stretch factor for Darlington and a 0.6% stretch factor for Pickering, and weighted the stretch factors by the most recent OEB approved production forecast to determine the 0.3% stretch factor.

OPG, and consultants that it retained, have pointed out the challenges faced in benchmarking nuclear costs and operations. There is a limited population of nuclear operators world-wide. Further, the nuclear technology chosen has implications on capital versus operating functions and costs. The pool of CANDU nuclear operators is even more limited. The age and size of stations also puts constraints on scale efficiencies.[160]

The 2016 nuclear benchmarking report was filed in response to an interrogatory. The 2013-2015 TGC result for Darlington was second quartile and Pickering remained in the fourth quartile. OPG explained that the drop in performance for Darlington was related to the 2015 vacuum building outage and outages to replace primary heat transport pump motors.

In addition to station specific results, the annual nuclear benchmarking reports provide utility results for major operators. OPG placed 10th out of a comparator group of 13 for the 2012-2014 three year rolling average TGC. OPG's performance slipped to 12th out of a comparator group of 13 for the 2013-2015 TGC. OEB staff and several intervenors submitted that these utility results supported a higher stretch factor; most parties proposed 0.6%. SEC submitted that a stretch factor based on a benchmarking result for

[159] Exh A1-3-2 page 33.
[160] Exh. F2-1-1, AIC page 78, Tr Vol 13 pages 13-14.

OPG as a whole is appropriate as ratepayers pay a single nuclear payment amount. OPG argued that the submissions do not reflect historic performance or realistic improvement opportunities, specifically the inherent limitations of Pickering.

SEC submitted that, should the OEB decide that station specific results should underpin the stretch factor, the most recent TGC results from the 2016 nuclear benchmarking report should be used and the production forecast for the test period should be used. SEC calculated a stretch factor ranging from 0.45% to 0.46% over the plan term (2017-2021).[161] LPMA proposed that these results be rounded up to 0.5%. OPG argued that the OEB has not calculated any aspect of a stretch factor based on forecast performance. While OPG does not support the use of the 2016 nuclear benchmarking results, it calculated a stretch factor of 0.43% based on the TGC data and the proposed methodology.

Findings

The OEB agrees that determining an appropriate nuclear generation industry productivity factor for the test period would be a challenge. Further, the EB-2012-0340 report noted the limited reference population of CANDU operators and the difficulty in specifying an appropriate cost function for nuclear assets.

The absence of a productivity factor for the current Custom IR plan does not mean that future applications should have the same structure. The OEB’s expectations regarding an independent productivity study continue, and OPG should be prepared to file work plans for this study when DRP approaches its conclusion.

The OEB does not accept the 0.3% stretch factor proposed by OPG. In the absence of an econometric study, the OEB agrees with the parties who submitted that the 2016 nuclear benchmarking report of 2015 TGC results is the best reference for the Custom IR stretch factor.

OPG argues that 2015 was not a typical year due to the vacuum building outage and PHT motor replacements. Benchmarking, by its nature, compares the performance of entities. Those entities face challenges over time, including outages and shutdowns, just as OPG does. TGC data are presented as three-year rolling averages for OPG and for the comparison utilities. The OEB finds that this presentation of benchmarking performance is reasonable and addresses those years for which operations are atypical. In further support of this finding, the OEB notes that the benchmarking results filed in this proceeding are directionally consistent with the results of nuclear

[161] SEC Submission page 131.

benchmarking analyses considered in, and which the OEB has commented on and based decisions on, in previous payments applications.[162]

Pickering TGC has been consistently in the fourth quartile. OPG argues that Pickering is limited by the size of its units and the first generation CANDU design, and that it cannot be as cost competitive as other nuclear stations. OPG's proposed stretch factor calculation is based on benchmark performance of each OPG facility and includes comparison with major operators and seven single station operators.[163] OPG has determined that the stretch factor based on 2014 data is 0.3%, while the stretch factor based on 2015 data is 0.43%.

The OEB finds that OPG's arguments regarding the limitations of Pickering are contrary to OPG's application for enabling and restoration costs for Pickering and the forecast of $4 billion to operate Pickering beyond 2020. Energy Probe argued: "If OPG can't find a way to move Pickering into, at least the median level of performance, Energy Probe questions why the plant should continue to remain in operation."[164]

That said, as a single OPG nuclear payment amount is set reflecting both Pickering and Darlington, the OEB finds that benchmarking by major operators is the appropriate reference in any event. The OEB notes that both Pickering and Darlington are proposed to be in operation during the current five-year term, and does not find OPG's argument that Pickering and Darlington should receive separate attention, and that emphasis should be placed of Darlington,[165] to be convincing. OPG's 2015 overall performance against the comparators, which excludes the seven single station operators, is 12th out of 13.[166] This is bottom quartile performance, and the OEB finds that a stretch factor of 0.6% is appropriate.

The OEB's findings with respect to benchmarking are found in section 5.4 of this Decision. The benchmarking results are a supporting factor for reductions in OM&A as discussed in section 5.6 of this Decision.

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[162] Decision with Reasons EB-2013-0321, November 20, 2014, pp. 45-47, Decision with Reasons EB-2010-0008, March 10, 2011, pp. 45-46, Decision with Reasons, November 3, 2008, pp. 28-32. OEB staff's submission (May 19, 2017 [revised July 10, 2017 following OPG's review of the redacted material] pages 82-84) references the benchmarking results filed in this application relative to the performance reported in the previous payments applications.
[163] Reply Argument page 60.
[164] Energy Probe Submission page 45.
[165] Reply Argument pages 259-260.
[166] Exh L-6.2-SEC-63, Tr Vol 6 page 129.

8.2.3 Application of Stretch Factor

As previously noted, OPG has proposed that the stretch factor apply to base and allocated corporate support OM&A. The annual revenue requirement related to these costs is approximately $1,700 million and represents 75% of OM&A. These OM&A categories were selected as it is reasonable to expect the company to make incremental performance improvements in these costs during the Custom IR term. The following table summarizes historical and forecast operating costs. OPG's proposal would apply to the costs at lines 1 and 8:

Table 35: Nuclear Operating Costs

Line No.	Cost Item	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	OM&A:									
	Nuclear Operations OM&A									
1	**Base OM&A**	1,127.7	1,127.1	1,159.6	1,201.8	1,210.6	1,226.0	1,248.4	1,264.7	1,276.3
2	**Project OM&A**	105.7	101.9	115.2	98.2	113.7	109.1	100.1	100.2	86.8
3	**Outage OM&A**	277.5	221.3	313.7	321.2	394.6	393.8	415.3	394.4	308.5
4	**Subtotal Nuclear Operations OM&A**	1,510.8	1,450.3	1,588.5	1,621.3	1,718.9	1,728.9	1,763.8	1,759.4	1,671.6
5	**Darlington Refurbishment OM&A**	6.3	6.3	1.6	1.3	41.5	13.8	3.5	48.4	19.7
6	**Darlington New Nuclear OM&A[1]**	25.6	1.5	1.3	1.2	1.2	1.2	1.2	1.3	1.3
7	**Allocation of Corporate Costs**	428.4	416.2	418.8	442.3	448.9	437.2	442.7	445.0	454.1
8	**Allocation of Centrally Held and Other Costs[2]**	413.5	416.9	461.0	331.9	80.2	118.2	108.3	91.1	81.3
9	**Asset Service Fee**	22.7	23.3	32.9	28.4	27.9	27.9	28.3	22.9	20.7
10	**Subtotal Other OM&A**	896.5	864.1	915.5	805.0	599.7	598.3	584.1	608.6	577.1
11	**Total OM&A**	2,407.3	2,314.5	2,504.0	2,426.3	2,318.6	2,327.1	2,347.9	2,368.0	2,248.7
12	**Nuclear Fuel Costs**	244.7	254.8	244.3	264.8	219.9	222.0	233.1	228.2	212.7
	Other Operating Cost Items:									
13	**Depreciation and Amortization**	270.1	285.3	298.0	293.6	346.9	378.7	384.0	524.9	338.1
14	**Income Tax**	(76.4)	(61.5)	(31.8)	(18.7)	(18.4)	(18.4)	(18.4)	51.2	51.7
15	**Property Tax**	13.6	13.2	13.2	13.5	14.6	14.9	15.3	15.7	17.0
16	**Total Operating Costs**	2,859.3	2,806.2	3,027.8	2,979.4	2,881.6	2,924.4	2,961.9	3,187.9	2,868.2

Source: Exh F2-1-1 Table 1

OEB staff and several intervenors submitted that OPG's proposal was too narrow; most parties submitted that the stretch factor should apply to total OM&A (i.e. line 11 of the table), although some parties observed that certain costs, e.g. DRP, are CRVA eligible. OPG argued that it is not reasonable to expect additional efficiencies in the other cost categories. For example, outages are unique planned work not a steady state function, and centrally held costs are non-discretionary costs that are not operational costs, e.g. insurance, for which savings cannot be realized.

Most intervenors also proposed that the stretch factor should also apply to capital, referring to the OEB's decision in the Toronto Hydro-Electric System Limited (THESL) Custom IR proceeding, EB-2014-0116. The OEB found that the THESL application did not contain enough productivity incentives and decided that the stretch factor should apply to THESL's custom capital factor.[167] SEC noted that TGC reflects benchmarking of both operating and capital costs, and that the stretch factor should apply to both operating and capital costs as well, referencing the OEB's same finding in this regard with respect to THESL's recent Custom IR application.[168] SEC submitted that, if the stretch factor is only applied to OM&A, the metric that sets the stretch factor should be an operating cost metric. OPG argued that its capital projects are large and discrete while distributors execute routine and repetitive capital work. The stretch factor should only be applied to certain operating costs. The stretch is based on TGC because it was determined to be the best overall financial metric for OPG by ScottMadden.

Findings

The OEB finds that it is appropriate to apply the stretch factor to operations OM&A, i.e. the sum of base, project and outage OM&A at line 4 of the table above, and corporate costs at line 7 of the table above. The enabling costs for PEO are addressed in section 5.7 of this Decision, and are excluded from the stretch factor.

The OEB rejects OPG's arguments that project OM&A and outage OM&A activities are outside the scope of what OPG routinely undertakes as part of its operations. The OEB has reviewed project OM&A Business Case Summaries over the course of this proceeding and agrees with parties that there are opportunities to improve productivity. Each Darlington unit undergoes a planned outage every three years and Pickering units undergo a planned outage every two years. The OEB accepts that certain activities may be different from previous outages, but finds that there are outage OM&A productivity opportunities as there are many standard elements included in the scope of each outage.[169]

Consistent with the OEB's finding in the THESL Custom IR application EB-2014-0116 (referenced above), the OEB finds that the stretch factor should apply to both capital and operating costs. Thus, the stretch factor will also apply to nuclear operations and support service in-service capital additions. The OEB expects that OPG will achieve

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[167] Decision and Order, Toronto Hydro-Electric System Limited, EB-2014-0116, page 27, "The second custom aspect of Toronto Hydro's Application is a custom capital factor. It is described as a scaling adjustment that will annually incorporate the cost recovery for THESL's capital program from 2016-2019. It is calculated by dividing the difference between the year over year capital requirement by the total revenue requirement. That percentage amount is then added to base rates. The C-factor is the only means of capital recovery proposed for 2016-2019 (after rebasing)."
[168] SEC Submission page 131, referencing the EB-2014-0116 Decision and Order at page 18.
[169] Exh F2-4-1 page 6.

productivity improvements with respect to the delivery of these programs during the test period.

The OEB's findings on nuclear operations capital and rate base are found in section 5.2 of this Decision.

8.2.4 ROE Update

OPG proposes that the revenue requirement impact of any change in ROE in the Custom IR term be recorded in the new Nuclear ROE Variance Account. The OEB is not approving the new account. This aspect of the application is discussed in section 6 of this Decision.

8.2.5 Other Elements

Annual reporting for the nuclear business is addressed in section 10.3.

OPG proposes that a regulatory review may be initiated if OPG's annual reporting shows performance outside the ± 300 basis points ROE dead band, or if performance erodes to unacceptable measures. The OEB's review of this proposal is in section 8.1.

As noted in section 8.1, several intervenors have proposed an increase to the $10 million threshold that OPG applies for impact statements and accounting orders. LPMA submitted that the threshold should be updated to $14.4 million for the nuclear business, while CCC submitted that OPG is an integrated company and that the corporate threshold should be $25 million.

Findings

The OEB finds that the $10 million threshold for OPG is appropriate. The maximum materiality threshold for electricity distributors, including Hydro One, is $1 million. Retaining the $10 million threshold would be consistent with the payment order provisions of EB-2012-0002 and EB-2013-0321. The OEB finds that the $10 million threshold will continue to apply for all matters, except for the filing of project business cases where the threshold is $20 million.

9 MID-TERM REVIEW

OPG seeks approval of a mid-term production review in the first half of 2019. The mid-term application would seek an update of the nuclear production forecast and related nuclear fuel expense for the period July 1, 2019 to December 31, 2021 and disposal of applicable audited 2018 year-end deferral and variance account balances. In the second impact statement, Exh N2-1-1, OPG updated its application to exclude the revenue requirement impact of the D2O project. OPG proposed that the prudence review of the D2O project occur at the mid-term review.

Historical production forecasts are reviewed in section 5.1. For a number of reasons, OPG has never achieved its production forecast in the period 2008 to 2015. OPG states that the mid-term review is necessary as there is substantial uncertainty with respect to production in the second half of the Custom IR term. The impact of the production variance would be recorded in the proposed Mid-term Nuclear Production Variance Account. It is OPG's view that its proposal is consistent with the rate smoothing requirements of O. Reg. 53/05 which require the OEB to determine nuclear revenue requirement for each year on a five-year basis. While the revenue requirement must be determined on a five-year basis, there is no similar requirement for production.

Several intervenors objected to the mid-term review, noting the OEB's expectation in the Rate Handbook of no further updates once rates are set in a Custom IR unless there are exceptional circumstances.[170] In OPG's view, it is unfair to require that its application comply with the Rate Handbook when the application was filed six months prior to its issuance.

Based on review of historical performance, CME argued that the mid-term review asymmetrically protects OPG. The PWU submitted that the proposal is reasonable and noted that the proposal is symmetrical. Similarly, OEB staff observed that an early or a late completion of Darlington Unit 2 refurbishment would have a significant impact on production, one favouring OPG, the other favouring ratepayers.

There were several submissions proposing revisions to the scope of the mid-term review, e.g. limiting scope to DRP or PEO, or revising scope to review DRP or PEO costs. OPG argued that reduced scope would result in an ineffective production forecast review, while cost review is addressed by other means.

AMPCO submitted that Darlington Unit 2 return to service was uncertain, and that the OEB should establish 2020 and 2021 payment amounts on an interim basis, and

[170] Handbook for Utility Rate Applications, October 13, 2016, page 26.

finalize them as part of the mid-term review. OPG argued that this submission is contrary to O. Reg. 53/05.

Should the OEB approve OPG's proposed mid-term review, OEB staff submitted that the review should be limited to 2020 and 2021 as OPG's previous applications have been two-year cost of service followed by a one-year lag. OPG did not object to this submission, providing it was able to clear the Pension & OPEB Cash Versus Accrual Differential Deferral Account at the same time as its 2018 hydroelectric payment amounts application.

Findings

The OEB does not approve the mid-term review proposal related to production forecast. As a result, the OEB does not approve the Mid-Term Nuclear Production Variance Account that was proposed to record the impacts of adopting a more accurate production forecast for the second half of the Custom IR term.

One of the reasons put forward by OPG for a mid-term review is the inherent inaccuracy of forecasting, particularly for the five-year term. The OEB finds that this reason is not consistent with the Custom IR framework. This is supported by the Rate Handbook which states that:

> 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.[171]

While the OEB agrees that it is not reasonable for OPG to have aligned its application perfectly with the Rate Handbook given the timing of the latter, the expectations regarding Custom IR framework applications were first noted in the RRF Report in 2012. The OEB noted that it "expects a distributor's application under Custom IR to demonstrate its ability to manage within the rates set, given that actual costs and revenues will vary from forecast."[172]

The OEB agrees with the intervenors that the forecasting of production is not an exceptional circumstance requiring a mid-term review.

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[171] Handbook for Utility Rate Applications, page 26.
[172] Report of the Board, *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, October 18, 2012, page 19.

AMPCO submitted that the mid-term review of load forecast has been previously approved for one distributor's Custom IR application,[173] and that the rates for the later period were declared interim. AMPCO proposed the same for OPG. The OEB agrees with OPG that approving interim payment amounts for the later years of the test period is contrary to section 6(2)12 of O. Reg. 53/05, so this approach is not a viable option for OPG.

OPG's mid-term review proposal also refers to increased production risk during the second half of the five-year term due to the work required to enable PEO and DRP. Some of the parties proposed limiting the scope of the mid-term review to PEO and/or DRP. OPG argued that limiting the review to PEO or DRP would be inappropriate as it ignores the interrelationship of these programs with plant operations. The OEB does not approve a mid-term review for production forecast specifically related to PEO or DRP.

The OEB's findings regarding PEO are in section 5.7. Should the outcome of the technical assessments to determine fitness for service beyond 2020, or system planning decisions, significantly impact operation of Pickering in 2021, OPG shall notify the OEB. In cross-examination, OPG confirmed that ceasing Pickering operation in 2020, "would be a very significant event that would fundamentally change the outlook on the company, and we would come back to the Board and seek direction in that event."[174]

The OEB's findings on DRP are in section 5.3. The OEB heard a great deal of evidence in this proceeding related to the ten years of planning involved in mapping out the DRP project. The OEB therefore finds a mid-term review to deal with any uncertainties surrounding DRP to be unnecessary. OPG's evidence is that there will be uncertainties related to the project, and that OPG is well positioned to deal with those issues. In the event that OPG does not proceed with refurbishment of Unit 3, this would represent a fundamental change to the outlook of the company and OPG would most likely return to the OEB to seek direction. For these reasons, a mid-term review to deal with production forecast related to DRP is unnecessary.

In the event that PEO or DRP do not proceed as OPG has set out in its application, there is the possibility that OPG's regulated return will exceed the $\pm$ 300 basis points ROE dead band. At that point, a regulatory review may be initiated.

The OEB's direction with respect to future deferral and variance account balance review and disposition is discussed under section 7, Deferral and Variance Accounts, and section 11, Payment Amount Smoothing and section 12, Implementation.

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[173] Oshawa PUC Networks Inc., EB-2014-0101.
[174] Tr Vol 6 page 158.

10 REPORTING AND RECORD KEEPING

10.1 General Reporting

The EB-2010-0008 decision set out financial and operating reports that OPG would file beginning in 2011.[175] OPG proposed to continue to file those reports. In reply submission, OPG requested a two-week extension to file the actual regulatory return, after tax on rate base. The current requirement is a filing by June 30th of each year, and OPG noted that the timeline is challenging as corporate tax returns are also due at the same time.

OEB staff had no concerns with the general reporting. OEB staff noted in its submission that the Rate Handbook requires rate-regulated utilities to propose scorecards in their next cost based rate applications. The Rate Handbook was issued in October 2016, approximately five months after OPG's application was filed. OEB staff said it expects that OPG will supplement (or summarize) its reporting with a proposal for a detailed scorecard as part of its next cost based application.

Findings

OPG shall continue to file the financial and operating reports set out the in the EB-2010-0008 decision. The OEB approves the extension requested for the filing of the actual annual regulatory return, after tax on rate base. That report shall be filed by July 31st of each year.

The OEB's findings with respect to DRP reporting, regulated hydroelectric reporting and nuclear reporting are found in sections 5.3, 10.2 and 10.3 respectively.

OPG shall file a proposal for a detailed scorecard as part of its next cost based application. OPG shall refer to the performance scorecard guidance in the Rate Handbook.

10.2 Hydroelectric Performance Reporting

OPG proposed to annually report on safety, reliability and cost effectiveness of the regulated hydroelectric business. The measures are those that OPG has included in

[175] EB-2010-0008, Decision with Reasons, March 10, 2011, page 150.

previous payment amount applications, and are summarized below. OPG proposed to file the prior year's actual performance and the targets for the current year.

Hydroelectric Performance Measures

Category	Measure
Safety	All Injury Rate (per 200k hours)
	Environmental Performance Index (%)
Reliability	Availability Factor (%)
	Equivalent Forced Outage Rates (%)
Cost Effectiveness	OM&A Unit Energy Cost ($/MWh)

OEB staff submitted that the targets for the prior year should be filed in addition to the performance for the prior year. OEB staff also submitted that five years of performance results should be filed to be consistent with the Electricity Distributor Scorecards. OPG did not object to these submissions.

Through technical conference questions, and oral hearing cross-examination, OPG confirmed that the cost effectiveness measure includes only base OM&A and some project OM&A. OPG also confirmed that it does not propose to provide quartile analysis for the OM&A Unit Energy Cost. This measure is based on approximately 50% of the total OM&A costs. It also excludes the Gross Revenue Charge, which is the single largest hydroelectric expense.

OEB staff observed that in 2016, "OPG adopted Total Generating Cost (TGC) per MWh as an enterprise-wide measure of operational cost effectiveness, in addition to TGC per MWh metrics for each of the Nuclear and Hydroelectric operations."[176] OEB staff submitted that OPG should report both OM&A Unit Energy Cost and TGC/MWh for the regulated hydroelectric business. In reply, OPG stated that it does not calculate TGC/MWh separately for the regulated hydroelectric business, and it does not have a TGC/MWh target for the regulated hydroelectric business.

[176] Exh N1-1-1 Attachment 1 page 4.

Findings

OPG agreed with the OEB staff submission on hydroelectric performance reporting with the exception of the OEB staff proposal regarding the TGC/MWh measure for the regulated hydroelectric business.

The OEB observes that OPG's hydroelectric OM&A Unit Energy Cost measure is the same information that OPG has filed in previous cost based proceedings. The data source is the Electricity Utility Cost Group (EUCG) and in OPG's view it is a reliable and fair representation of the trend within the hydroelectric business.[177] However, the OEB found in the previous proceeding, EB-2013-0321, that the EUCG data was inadequate as only 50% of total OM&A expense was benchmarked, and there was no independent review. In this proceeding, OPG filed a hydroelectric benchmarking review prepared by Navigant[178] which is discussed in section 8.1 of this Decision. The OPG hydroelectric performance reporting proposal does not include any additional cost measures benchmarked by Navigant. At the oral hearing, OPG confirmed that it does not propose to provide benchmark quartile analysis. The OEB finds that OPG's proposal for hydroelectric performance reporting is very limited compared with the performance reporting for the nuclear business, which is discussed in section 5.4 of this Decision.

OPG's consultant, ScottMadden, and OPG identified TGC/MWh as one of three key metrics for the nuclear business in 2009 and OPG has included TGC/MWh in its annual nuclear performance reports since 2009. The annual nuclear performance reports that will be filed with the OEB will include TGC/MWh for Pickering, Darlington and OPG Nuclear and the benchmarked quartile will also be identified in the reports. OPG recognized that TGC/MWh is a key measure of operational cost effectiveness and adopted the measure in 2016 on an enterprise wide basis and for the hydroelectric business as well. OEB staff proposed that OPG file TGC/MWh for the regulated hydroelectric business. OPG replied that it does not calculate TGC/MWh for the regulated hydroelectric business separately from the unregulated hydroelectric business, nor does it have separate targets. OPG stated in reply argument that it considers the efficiency of operations as a business and within regions, which include both regulated and unregulated plants.

While OPG does not calculate TGC/MWh for the regulated hydroelectric facilities, there is no indication in the evidence that the measure cannot be calculated, only that OPG does not currently do so. Given the limited proposed hydroelectric performance reporting, the OEB finds that OPG shall also report on TGC/MWh for the regulated

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[177] Tr Vol 9 page 88.
[178] Exh A1-3-2 Attachment 2.

hydroelectric facilities on an annual basis. The OEB understands that at present there is no target, and none is required to be filed.

OPG shall report the five metrics listed in the chart above and TGC/MWh for the regulated hydroelectric business.

The annual hydroelectric reporting shall commence in 2018. In 2018 OPG shall file 2017 hydroelectric performance results, 2017 targets as well as 2018 targets. As noted above, no targets will be filed for TGC/MWh. The hydroelectric performance results for the historical period, 2013-2016, shall also be filed.

All the hydroelectric performance reports shall be filed by April 30th.

10.3 Nuclear Performance Reporting

OPG proposed to annually report on safety, reliability and cost effectiveness of the nuclear business. The 20 measures are those that OPG has included in previous payment amount applications, and are summarized below. OPG proposed to file the prior year's actual performance and the targets for the current year for Darlington and Pickering.

Nuclear Performance Measures (Separate measures will be filed for Darlington and Pickering Stations)	
Category	**Measure**
Safety	All Injury Rate (per 200k hours)
	Collective Radiation Exposure (person rem/unit)
	Airborne Tritium Emissions (curies)
	Industrial Safety Accident Rate (#/200k hours)
	Fuel Reliability Index (microcuries /gram)
	2-year Reactor Trip Rate (#/7000 hours)
	3-year Auxiliary Feedwater System Unavailability (#)
	3-year Emergency AC Power Unavailability (#)
	3-year High Pressure Safety Injection Unavailability
Reliability	Forced Loss Rate (%)
	Unit Capability Factor (%)
	Nuclear Performance Index (%)
	On-line Deficient Maintenance Backlog (work orders / unit)
	On-line Corrective Maintenance Backlog (work orders / unit)
	Chemistry Performance Indicator Annual YTD (#)
Cost Effectiveness	Total Generating Cost per Net MWh ($/MWh)
	Non-Fuel Operating Cost per Net MWh ($/MWh)
	Fuel Cost per Net MWh ($/MWh)
	Capital Cost per MW Design Electrical Rating ($k/MW)
Human Resources	18-month Human Performance Error Rate (#/10k ISAR hours)

OEB staff submitted that the quartile performance for Darlington and Pickering should be filed for all the measures and that the Unit Capability Factor (UCF), Nuclear Performance Index (NPI) and Total Generating Cost (TGC) performance of OPG nuclear should be filed as well. OPG's original proposal was to file UCF and TGC on a normalized basis, i.e. normalized for Darlington production during the DRP. However, following cross-examination, and in its Argument in Chief, OPG now proposes to file both normalized and non-normalized performance.

OEB staff submitted that the targets for the prior year should be filed in addition to the performance for the prior year. OEB staff also submitted that five years of performance results should be filed to be consistent with the Electricity Distributor Scorecards. OPG did not object to these submissions.

Findings

The OEB accepts the OEB staff submission, which has not been opposed by OPG.

OPG shall report the 20 metrics listed in the chart above for Pickering and Darlington separately. For the years which are impacted by DRP, OPG shall report on a normalized and non-normalized basis for Darlington.

OPG shall report UCF, NPI and TGC for OPG Nuclear. For the years which are impacted by DRP, OPG shall report on a normalized and non-normalized basis for OPG Nuclear.

The annual nuclear reporting shall commence in 2018. In 2018 OPG shall file 2017 nuclear performance results, 2017 targets as well as 2018 targets. The nuclear performance results for the historical period, 2013-2016, shall also be filed. The Darlington and OPG performance results would not be normalized for the 2013-2016 period as DRP does not apply for this period.

All the nuclear performance reports shall be filed by April 30th. As reviewed in cross-examination, the performance reports shall be refiled later in the year when the benchmark quartile results are available, no later than November 30th.[179]

[179] Tr Vol 6 page 147.

11 PAYMENT AMOUNT SMOOTHING

Background

In November 2015, O. Reg. 53/05 was amended to include processes and parameters regarding the smoothing of nuclear payment amounts from January 1, 2017 to the end of the DRP. The amended regulation stated that the OEB will determine the portions of the revenue requirement that will be deferred for recovery "with a view to making more stable the year-over-year changes in the payment amount." As noted in section 7 of this Decision, the amended regulation required that a Rate Smoothing Deferral Account (RSDA) be established to record the deferred amounts. The regulation required the nuclear revenue requirement deferral on a five-year basis for the first ten years of the deferral period, and thereafter on a basis to be determined by the OEB. It further stipulated that OPG must record interest on the RSDA balance at the OEB-approved long term debt rate, compounded annually.

The application as originally filed in May 2016 proposed an 11% increase on current base nuclear payment amounts and 11% increases for each year of the test period. With this proposal, OPG forecast that $1.6 billion would be added to the RSDA and that there would be $300 million of interest in 2017-2021. The monthly bill of a typical residential customer would increase $1.05 each year.

O. Reg. 53/05 was amended again in March 2017 "with a view to making more stable the year-over-year changes in the OPG weighted average payment amount" (emphasis added). The amended regulation defined the OPG weighted average payment amount (WAPA) to include both the hydroelectric and nuclear payment amounts, as well as deferral and variance account riders. OPG revised its application in light of the amended regulation and proposed a 2.5% year over year increase in WAPA.[180] With this proposal, OPG forecast that $1.0 billion would be added to the RSDA and that there would be $116 million of interest in 2017-2021.[181] The monthly bill of a typical residential customer would increase $0.65 each year.

OPG provided an evaluation of its proposal considering the following principles:

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[180] Impact statement Exh N3-1-1.

[181] Over the entire time horizon of OPG's proposal (i.e. the forecast 10-year deferral period plus the 10-year "recovery period", over which the balance in the RSDA would be recovered), the cumulative interest would amount to $1.4 billion: Tr Vol 22 page 50.

- Financial viability (leverage and cash flow impacts)
- Rate stability
- Long-term perspective
- Post-recovery transition
- Intergenerational equity
- Customer bill impact

OPG stated that its proposal was consistent with O. Reg. 53/05, the objectives of the OEB and the outcomes identified in the Renewed Regulatory Framework.

The following table summarizes the 2016 payment amounts, riders and WAPA, and OPG's proposal for the test period. The final column in the table represents the current payment amounts and WAPA based on the 2017 production forecast.

Table 36: OPG Rate Smoothing Proposal

								Note 1
	Exh N3-1-1	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2017**
1	Hydroelectric Payment Amount ($/MWh)	40.72	41.71	42.33	42.97	43.61	44.27	40.72
2	Hydroelectric Rider ($/MWh)	3.83	1.44	1.44				
3	Hydroelectric Production (TWh)	33.0	33.0	33.0	33.0	33.0	33.0	33.0
4	Nuclear Revenue Requirement ($M)		3161.4	3185.7	3273.2	3783.5	3397.8	
5	Nuclear Production Forecast (TWh)	46.80	38.10	38.47	39.03	37.36	35.38	38.10
6	Unsmoothed Nuclear Payment Amount ($/MWh)	59.29	82.98	82.81	83.86	101.27	96.04	59.29
7	Smoothed Nuclear Payment Amount ($/MWh)	59.29	76.39	78.60	84.83	88.21	92.02	59.29
8	%Change in Smoothed Nuclear Payments		29%	3%	8%	4%	4%	
9	Nuclear Rider ($/MWh)	13.01	2.85	2.85				
10	WAPA (lines 1,2,3,5,7,9) ($/MWh)	60.97	62.49	64.06	65.66	67.30	68.98	50.67
	Source: RRWF, WAPA formula as per O. Reg. 53/05							
	Note 1: 2017 payment amounts for period up to implementation date							

Submissions on Smoothing

Based on an analysis using OPG's proposal, but no additions to the RSDA (i.e. zero smoothing), OEB staff calculated that the monthly bill of a typical residential customer would increase an average of $0.82, instead of $0.65 resulting from OPG's proposal. OEB staff also observed that the bill impact of the unsmoothed scenario is well below the 10% total bill impact threshold that the OEB typically considers requires mitigation, while acknowledging that "[z]ero smoothing is not an option; the regulation requires that the WAPA be made 'more stable'".[182] OEB staff submitted that smoothing of only the 2020 revenue requirement, the year with the largest step change, would achieve the smoothing objectives of O. Reg. 53/05 and would reduce the additions to the RSDA and

[182] OEB staff submission, page 178.

the related carrying charges. Similarly, Energy Probe proposed that the OEB should approve the smallest deferred amount possible.

In March 2017, the Province announced the Fair Hydro Plan, which when implemented would result in electricity bill reductions of 25% for residential customers as well as many small businesses and farms. Bill increases would be limited by the rate of inflation for at least four years.[183] In cross-examination, and in submissions, OEB staff and several intervenors questioned whether significant smoothing of payment amounts was necessary given the pending legislation. OPG replied that, as a matter of law, it would be incorrect to interpret the smoothing provisions of O. Reg. 53/05 differently because of the Fair Hydro Plan.

SEC observed that the change from nuclear payment amount smoothing to WAPA smoothing effectively means the collection of more revenue requirement in the test period. SEC further argued that customers who are not on the Regulated Price Plan (RPP) will not receive the smoothing effects of the Fair Hydro Plan. In addition, while OPG analysis and OEB staff analysis assume payment amounts that transition on January 1, 2017, significant deferral and variance account riders ended on December 31, 2016, and new payment amounts have not been implemented yet. Non-RPP customers currently pay a commodity price that includes the OPG WAPA of $50.67/MWh (note 1 of Table 36 above), which is a decrease from the $60.97 2016 WAPA. Once the 2017 payment amounts are implemented, non-RPP customers could experience a significant increase in commodity price. SEC submitted that there should be no increase in WAPA from 2016 to 2017.

OEB staff submitted that the OEB could smooth WAPA by approving deferral and variance account rider effective dates that are later in the test period. OPG's 2012 year end account balances were disposed in riders over two years, but the disposition was weighted 60:40. OEB staff submitted that this option of smoothing was available in this proceeding as well. SEC observed that there will almost certainly be deferral and variance account riders in the later years of the test period. SEC submitted that the OEB could make assumptions about riders in the later years for the purposes of smoothing, or establish a formula and process to self-adjust when the riders are known. OPG replied that SEC's proposal would complicate future deferral and variance account applications and could limit the OEB's ability to respond in those proceedings.

OPG, OEB staff, CME, LPMA, SEC and VECC all suggested that the OEB not make a decision on smoothing until the payment amount order process when the final revenue requirement, final production forecast, deferral and variance account riders and effective

[183] The *Ontario Fair Hydro Plan Act, 2017* was enacted June 1, 2017.

date are known. OPG submitted that it would be helpful for the OEB to identify principles and parameters in order to focus the range of WAPA smoothing alternatives.

Findings

In section 7, the OEB has approved the Rate Smoothing Deferral Account (RSDA). The OEB agrees that a final decision regarding WAPA smoothing cannot be made until the outcomes of this Decision are reflected in unsmoothed hydroelectric and nuclear payment amounts and hydroelectric and nuclear payment amount riders. Once the unsmoothed payment amounts are known, rate smoothing can be considered.

Although the regulation requires smoothing and sets out certain broad parameters for achieving it, it leaves much of the mechanics of smoothing, including the determination of how much of the nuclear revenue requirement to defer, to the OEB's discretion. Because the parties agree that smoothing should not be determined until the payment amounts order stage, the OEB will not provide detailed directions to OPG concerning those mechanics as part of this Decision. It will be up to OPG to propose a reasonable smoothing approach that is consistent with the regulation. However, the OEB confirms that it agrees that the six guiding principles for smoothing that were identified by OPG are appropriate, subject to the following caveats.

First, although "rate stability" is important, the OEB is of the view that it does not necessarily follow that year over year increases should be <u>constant</u>, as proposed by OPG in its most recent smoothing proposal (a 2.5% annual WAPA increase was proposed). When OPG retools its smoothing approach in light of the revenue requirement and other determinations made in this Decision, it should not consider itself constrained by a straight line increase (although, to be clear, if OPG concludes that a straight line increase would best satisfy the objective of the regulation and the principles of the RRF, it may propose one).

Second, as noted by OEB staff and some intervenors, although much of OPG's application in respect of smoothing – and much of the resulting cross-examination – focused on the bill impacts of various smoothing proposals for residential consumers, it is also critical to consider the impact on other classes of consumers, some of whom will not see the same reductions under the Fair Hydro Plan. "Rate shock" in the first year of the test period should be avoided.

As noted in section 12, Implementation, the OEB has decided that the effective date for payment amounts will be June 1, 2017. The final implementation date will be subject to the completion of the payment amount order process set out below in the Order section. However, for efficiency, the draft payment amounts order shall include the following implementation date scenarios:

- March 1, 2018
- April 1, 2018
- May 1, 2018

OPG shall propose smoothing for each scenario including WAPA, bill impacts, deferred amounts and RSDA carrying charges. OPG shall determine forgone revenue riders for each scenario. In the normal course, the OEB establishes the recovery period for forgone revenue. As legislatively required smoothing is a unique feature of this proceeding. OPG shall propose a recovery period for forgone revenue in the draft payment amounts order. Similarly, OPG shall propose a recovery period for the disposition of the deferral and variance account balances approved in section 7 of this Decision. It would be helpful to include an analysis of customer bill impacts, and in that regard, OPG might consider including an updated version of its response to undertaking J20.1 which set out the bill impacts for medium and large businesses (which will not see the same smoothing effects of the Fair Hydro Plan that residential and other eligible consumers will see).

12 IMPLEMENTATION

OPG seeks approval for nuclear payment amounts to be effective January 1, 2017 and for each following year through to December 31, 2021. OPG seeks approval for hydroelectric payment amounts to be effective January 1, 2017 to December 31, 2017 and approval of the formula used to set the hydroelectric payment amounts for the period January 1, 2017 to December 31, 2021. The OEB issued an order on December 8, 2016, declaring the current nuclear and regulated hydroelectric payment amounts interim effective January 1, 2017.

A January 1, 2017 effective date for new payment amounts was supported by OEB staff and the Society. OEB staff submitted that the application was filed on May 27, 2016, shortly after 2015 audited results were available, and that OPG met the schedule set out in Procedural Order No. 1.

SEC, LPMA, CCC and VECC submitted that the effective date should be the first day of the month following the issue of the payment amounts order. The intervenors argued that OPG should have filed this complex application earlier in order for the OEB to approve a January 1, 2017 effective date. The intervenors noted that the time between filing and payment amounts order for the previous proceeding, EB-2013-0321, was 447 days. The intervenors also referred to the EB-2013-0321 decision in which the OEB did not approve the requested January 1, 2014 effective date. In that decision the OEB stated that its general practice is for final rates to become effective at the conclusion of the proceeding, and that this practice is predicated on a forecast test year.

OPG replied that the intervenors' references to the EB-2013-0321 filing date are misplaced as the application started as an incomplete filing. OPG argued that an earlier filing in this proceeding would have required large scale updates to the application. An earlier filing would not have included audited 2015 results and would not have reflected the release quality estimate for DRP, the final business case for PEO, the amended Bruce Lease agreement or the amendment to O. Reg. 53/05. OPG submitted that it struck an appropriate balance between providing the best available information and the proposed effective date.

In response to cross-examination by SEC, OPG filed undertaking J23.1 which provides the impact of the scenario should the OEB approve an effective date of September 1, 2017. OPG would collect the interim payment amounts until August 31, 2017 and would begin collecting payment amounts and riders approved by the EB-2016-0152 decision beginning on September 1, 2017. The undertaking response assumed that the OEB approved the full year revenue requirement, and OPG would record in the RSDA the difference between the interim and approved payment amounts on a WAPA basis for the period January 1 to August 31, 2017. SEC argued that the OEB should refuse to allow this interpretation of O. Reg. 53/05. OEB staff submitted that the purpose of the RSDA is to allow for the smoothing that the OEB determines, and that the RSDA does not relate to effective date.

As a solution, SEC submitted that the OEB could determine that the revenue requirement for the period January 1, 2017 to the effective date is equivalent to that resulting from current payment amounts.

OPG replied that its position is based on section 5.5 of O. Reg. 53/05 which clearly provides that the RSDA will record entries starting January 1, 2017.

As noted in the deferral and variance account section, and the smoothing section, OPG seeks disposition of 2015 year-end account balances using two year payment amounts riders commencing January 1, 2017. OEB staff submitted that the OEB could consider a later start date.

Findings

The OEB approves an effective date of June 1, 2017. OPG filed a substantial application on May 27, 2016, as well as three impact statements, the last on March 8, 2017. It is unrealistic of OPG to expect that a final decision would be rendered and a payment amounts order processed in time for January 1, 2017 payment amounts. OPG filed a complicated application which was comprised of a Custom IR application for its nuclear facilities, an IRM application for its regulated hydroelectric facilities, a review of DRP and consideration of PEO. OPG should have known that it would take more than seven months for the OEB to consider the application, render a decision and finalize a payment amounts order.

OPG submits that it struck a balance between filing current information and taking into account the time required for the processing of an application. Specifically OPG notes that if it had filed prior to May 27, 2016, it would not have been able to include audited 2015 results, the release quality estimate for DRP, the final business case for PEO, the amended Bruce Lease agreement or the amendment to O. Reg. 53/05. The OEB notes that the completion of some of these items was largely in the control of OPG. Knowing that it was filing a major payment amounts application, OPG could have taken steps to ensure that the inclusion of these elements in the application was possible. The OEB also notes that OPG filed three significant updates after the application was filed (two of which were under OPG's control). The fact that OPG filed significant updates runs counter to OPG's argument that it filed in May 2016 with a view to minimizing updates to the application.

It is the common practice of the OEB to establish new rates and payment amounts prospectively. However, as this has been a complicated case involving a lengthy submission and decision writing process, the OEB has decided it will not make payment amounts effective after this Decision is rendered.

The smoothing of payment amounts, as required by regulation, will help lessen some of the impact of the payment amounts on ratepayers during the test period. However, it will not totally alleviate the fact that ratepayers will have consumed power for the last seven months of 2017 (and for a period into 2018) at the existing rates and will now, after the fact, have to pay a new rate for those periods.

In arriving at the June 1, 2017 effective date, the OEB has attempted to balance the revenue requirement needs of OPG and rate certainty expected by ratepayers.

The OEB finds that the new smoothing requirement in the regulation does not require that the OEB approve an effective date as of January 1, 2017. To do so would run contrary to the OEB's mandate to set just and reasonable payment amounts. Smoothing is a mechanism used to minimize the impact of changes in payment amounts and how they will be collected from ratepayers. It does not affect the OEB's mandate to set the payment amounts, one aspect of which is to determine the effective date of new payment amounts. The regulation may state that smoothing take place over the entire period of the five-year term, but the OEB does not read the regulation to state that the new payment amounts must commence effective January 1, 2017 in order for that to occur. Had the regulation intended to require an effective date of January 1, 2017, it could have simply said so. The total 2017 rates will still be used to calculate smoothing – they will be based on five months at the old rates and seven months at the new rates.

Given the passage of time, in addition to the 2017 payment amounts, the OEB will be finalizing the hydroelectric payment amounts for 2018.

OPG shall file a draft payment amounts order reflecting the payment amount setting determinations in this Decision for nuclear based on the parameters established for the five-year term, and for hydroelectric based on the 2017 and 2018 parameters. Similar to its approach in its application, OPG may use appropriate assumptions for hydroelectric payment amounts for years three to five of the term for purposes of establishing the WAPA.

The draft payment amounts order will include the final revenue requirement and final production forecast for the nuclear facilities, and the final hydroelectric rate setting mechanism and 2017 and 2018 parameters, as reflected in the findings made by the OEB in this Decision. OPG shall include supporting schedules and a clear explanation of all the calculations and assumptions used in deriving the amounts used, and final unsmoothed payment amounts.

A revised Revenue Requirement Work Form shall be filed that reflects both the application and the OEB Decision.

The draft payment amounts order shall reflect all the implementation date scenarios described in section 11, Payment Amount Smoothing.

With regard to the calculation of the forgone revenue rider for the period starting June 1, 2017 to the implementation date, the nuclear forgone revenue should be based on the monthly forecast production underpinning the application and approved by the OEB. The hydroelectric forgone revenue shall be based on pro-rating the 2015 actual regulated hydroelectric production.

OPG is directed to provide a full description of each deferral and variance account as part of the draft payment amounts order. Accounting orders shall be filed for the new accounts approved in this Decision.

The schedule for the filing of the draft payment amounts order – and for submissions on the draft – is set out below in the Order section.

It is the OEB's expectation that OPG will file an application comprising the disposition of the next set of deferral and variance accounts, including OPG's proposal for the Pension and OPEB Cash vs. Accrual Differential account (that will address with detailed evidence OPG's proposal for the accounting method to be used going forward), at the same time as the implementation of the 2019 hydroelectric payment amounts.

The OEB will set out the process for cost claims for intervenor costs since May 30, 2017 in the final payment amounts order.

13 ORDER

THE ONTARIO ENERGY BOARD ORDERS THAT:

1. OPG shall file with the OEB, with a copy to the intervenors, a draft payment amounts order (including a smoothing proposal) that reflects the OEB's findings in this Decision and Order by **January 17, 2018**.

2. Intervenors and OEB staff shall file with the OEB, with a copy to OPG, any comments on the draft payment amounts order (including the smoothing proposal) by **January 26, 2018**.

3. OPG shall file with the OEB, with a copy to the intervenors, a response to any comments by **February 5, 2018**.

4. OPG shall comply with all reporting and filing requirements set out in this Decision and Order.

All filings to the OEB must quote the file number, EB-2016-0152 and be made electronically through the OEB's web portal at http://www.pes.ontarioenergyboard.ca/eservice/ in searchable/unrestricted PDF format. Two paper copies must also be filed at the OEB's address provided below. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at https://www.oeb.ca/oeb/_Documents/e-Filing/RESS_Document_Guidelines_final.pdf. If the web portal is not available parties may email their documents to the address below. Those who do not have internet access are required to submit all filings on a USB flash drive in PDF format, along with two paper copies. Those who do not have computer access are required to file seven paper copies.

All communications should be directed to the attention of the Board Secretary at the address below, and be received no later than 4:45 p.m. on the required date.

ADDRESS

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto ON M4P 1E4
Attention: Board Secretary

E-mail: boardsec@oeb.ca
Tel: 1-888-632-6273 (Toll free)
Fax: 416-440-7656

DATED at Toronto December 28, 2017

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

SCHEDULE A

DECISION AND ORDER

ONTARIO POWER GENERATION INC.

EB-2016-0152

DECEMBER 28, 2017

Excerpt: Section 78.1 of the *Ontario Energy Board Act, 1998,* S.O. 1998, c.15 (Schedule B)

Payments to prescribed generator

78.1 (1) The IESO shall make payments to a generator prescribed by the regulations with respect to output that is generated by a unit at a generation facility prescribed by the regulations. 2014, c. 7, Sched. 23, s. 7.

Payment amount

(2) Each payment referred to in subsection (1) shall be the amount determined in accordance with the order of the Board then in effect. 2014, c. 7, Sched. 23, s. 7.

Same, limitation re Ontario Power Generation Inc.

(3) The determination of a payment to Ontario Power Generation Inc. under this section shall not include any consideration of amounts related to activities of Ontario Power Generation Inc. carried out in relation to the *Ontario Fair Hydro Plan Act, 2017*. 2017, c. 16, Sched. 1, s. 44 (3).

Same

(3.1) The amounts referred to in subsection (3) include, without limitation, the following:

1. Amounts related to the appointment of Ontario Power Generation Inc. as the Financial Services Manager under the *Ontario Fair Hydro Plan Act, 2017*.
2. Amounts related to the charging of fees for performing duties as the Financial Services Manager.
3. Amounts related to exercising the powers and performing the duties of the Financial Services Manager.
4. Amounts related to the consolidation of the assets and liabilities for accounting purposes of any special purpose financing entities established under and for the purposes of that Act. 2017, c. 16, Sched. 1, s. 44 (3).

Board orders

(4) The Board shall make an order under this section in accordance with the rules prescribed by the regulations and may include in the order conditions, classifications or practices, including rules respecting the calculation of the amount of the payment. 2004, c. 23, Sched. B, s. 15.

Fixing other prices

(5) The Board may fix such other payment amounts as it finds to be just and reasonable,

(a) on an application for an order under this section, if the Board is not satisfied that the amount applied for is just and reasonable; or

(b) at any other time, if the Board is not satisfied that the current payment amount is just and reasonable. 2004, c. 23, Sched. B, s. 15.

Burden of proof

(6) Subject to subsection (7), the burden of proof is on the applicant in an application made under this section. 2004, c. 23, Sched. B, s. 15.

Order

(7) If the Board on its own motion or at the request of the Minister commences a proceeding to determine whether an amount that the Board may approve or fix under this section is just and reasonable,

(a) the burden of establishing that the amount is just and reasonable is on the generator; and

(b) the Board shall make an order approving or fixing an amount that is just and reasonable. 2004, c. 23, Sched. B, s. 15.

Application

(8) Subsections (4), (5) and (7) apply only on and after the day prescribed by the regulations for the purposes of subsection (2). 2004, c. 23, Sched. B, s. 15.

Section Amendments with date in force (d/m/y)

2004, c. 23, Sched. B, s. 15 - 01/01/2005

2014, c. 7, Sched. 23, s. 7 - 01/01/2015

2017, c. 16, Sched. 1, s. 44 (3) - 01/06/2017

SCHEDULE B

DECISION AND ORDER

ONTARIO POWER GENERATION INC.

EB-2016-0152

DECEMBER 28, 2017

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.

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SCHEDULE C

DECISION AND ORDER

ONTARIO POWER GENERATION INC.

EB-2016-0152

DECEMBER 28, 2017

MEMORANDUM OF AGREEMENT

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

MEMORANDUM OF AGREEMENT

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

WHEREAS OPG is a business corporation incorporated under the *Business Corporations Act* (Ontario) OBCA).

AND WHEREAS The Minister, on behalf of Her Majesty in right of Ontario, may acquire and hold shares of OPG, and has primary policy responsibility for the overall legislative and regulatory framework, established primarily under the *Electricity Act, 1998* and the *Ontario Energy Board Act, 1998,* and the applicable regulations, within which OPG must conduct its business operations.

NOW THEREFORE the parties hereto have agreed as follows.

1 DEFINITIONS/INTERPRETATION

1.1 The following terms shall have the meanings ascribed to them herein:

"Corporation" means "Ontario Power Generation Inc."

"EA" means the "*Electricity Act, 1998*" and its regulations and the phrase "the Act" has a corresponding meaning.

"Deputy Minister" means the Deputy Minister of Energy, a public servant appointed by the Lieutenant Governor in Council under the auspices of section 4 of the *Ministry of Energy Act, 2011;*

"Ministry" means the Ministry of Energy;

"Minister" means the Minister of Energy appointed by the Lieutenant Governor in Council under the auspices of the *Executive Council Act* (Ontario) and includes reference to such other member of the Executive Council as may be assigned the administration of the *Ministry of Energy Act, 2011* (Ontario) under the *Executive Council Act* (Ontario);

"MOA" means this Memorandum of Agreement, including any and all appendixes attached hereto;

"OBCA" means *Business Corporations Act* (Ontario);

"OEBA" means the *Ontario Energy Board Act, 1998* and its regulations, codes, or orders of the Ontario Energy Board, as applicable;

"OPG Board Chair" means the member of the Corporation's Board of Directors which is appointed by the Minister pursuant to a unanimous shareholder resolution made in writing, and who is designated by the Minister as Chair;

"Shareholder" means Her Majesty the Queen, in Right of the Province of Ontario, as represented by the Minister of Energy who holds all of the issued shares of the Corporation on behalf of the Crown, and "sole shareholder" shall have the same meaning.

2. PURPOSE OF THIS MEMORANDUM OF AGREEMENT

The parties hereto agree and acknowledge that the purpose of this MOA is as set out below:

2.1 To serve as the basis of agreement between OPG and its sole Shareholder on mandate, governance, performance, and communications of OPG.

2.2 To establish the accountabilities and relationships solely between OPG and the Shareholder. In its discretion, the Shareholder may waive or deem compliance of OPG's obligations as appropriate in the circumstances.

2.3 To promote a positive and co-operative working relationship between OPG and the Shareholder.

3 GOVERNANCE OF OPG

3.1 Under the OBCA, the OPG Board of Directors is responsible for supervising the management of the business affairs and operations of the Corporation, including a fiduciary duty to act honestly and in good faith with a view to the best interests of the Corporation and to exercise the skill as well as a standard of care and diligence that a reasonably prudent person would exercise in similar circumstances. As such, the Corporation operates as a business enterprise with a commercial mandate, governed in principle and at first instance by an independent Board of Directors who is responsible for the appointment of the President and Chief Executive Officer. The President and Chief Executive Officer and management are responsible for the day-to-day operations of the company.

3.2 The Minister shall be responsible for appointing or re-appointing, in a timely manner and following consultation with the Chair, as appropriate, the directors of OPG pursuant to the process established by the Public Appointments Secretariat and securities regulators' National Policy on Corporate Governance Guidelines.

3.3 As a reporting issuer of debt securities, OPG is subject to the disclosure standards and requirements of the *Securities Act* (Ontario) and shall make such disclosures as may be required.

3.4 As set out in subsection 53.1(2) of the EA, OPG and its subsidiaries are not agents of the Crown for any purpose, despite the Crown Agency Act.

3.5 OPG shall operate in an accountable and transparent manner with regard to the Corporation's governance, management, administration and operations. In this regard, OPG is subject to a number of statutes and Treasury Board/Management Board of Cabinet directives. A list of applicable statutes and directives is set out in Appendix 1 attached hereto.

3.6 Notwithstanding the foregoing, the Shareholder may at times direct OPG to undertake special initiatives. Such directives shall be written declarations by way of a Unanimous Shareholder

Agreement and/or Declarations and resolutions, in accordance with section 108 of the OBCA, which shall be made public by OPG within a reasonable timeframe by publishing such agreements, declarations and resolutions on the Corporation's website.

3.7 Unless otherwise directed by the Shareholder or statute, OPG shall operate in Ontario in accordance with the highest corporate standards, including but not limited to the highest corporate standards in the areas of corporate governance and social responsibility. OPG shall continue to benchmark its corporate governance practices against the securities regulators' National Policy on Corporate Governance Guidelines, as well as other leading governance organizations, as appropriate.

4 MANDATE

4.1 The objects of OPG include, in addition to any other objects, owning and operating a diversified portfolio of generation assets and facilities.

4.2 OPG shall leverage its assets and expertise to generate new revenues on a commercially sound basis, including the making of strategic investments and acquisitions in the electricity sector, as well as in related business opportunities inside and outside Ontario, on its own or in partnership as appropriate, for the benefit of the Corporation and the Shareholder.

4.3 OPG shall continue to operate as a respected, publicly-owned electricity generation enterprise and to operate its assets efficiently and cost-effectively, and to deliver value both to Ontario's ratepayers and taxpayers.

4.4 OPG shall ensure that it conducts its operations in full compliance with all laws and regulations and serves as a model in regard to public and employee safety, environmental practices, corporate citizenship, community engagement and First Nations and Métis relations.

4.5 OPG shall undertake generation development projects in support of the Province's electricity planning initiatives, including the Long Term Energy Plan, as may be updated from time to time.

4.6 OPG shall support the Province of Ontario's efforts to fulfill the Crown's constitutional duty to consult and accommodate Aboriginal peoples, where that duty arises in relation to OPG generation projects, by carrying out those procedural aspects of the Crown's consultation obligations that are delegated in writing to OPG by the Province, including the Ministry.

4.7 The Province of Ontario and the Ministry supports the role of public power and mitigating electricity prices in Ontario and in doing so:

a. mandates that OPG maintain itself as a strong, viable public power component of the electricity sector at an appropriate scale and with generation portfolio diversity to ensure long-term operational and financial sustainability and to support OPG long term liabilities; and
b. mandates that OPG plan and operate its generation facilities based upon good utility practice recognizing safety, legal, regulatory, environmental and market factors.

4.8 OPG shall support the Province's economic development objectives where feasible, including generating financial benefits that remain within the Province of Ontario.

4.9 OPG shall serve the public interest and operate in a way that achieves a commercial rate of return, moderates overall electricity prices, and supports the efficient operation of the electricity market.

4.10 OPG shall earn a commercial rate of return and generate sufficient cash in order to maintain an investment grade credit rating, and service its borrowing needs for operations and projects; as well as supporting the opportunity to access public debt markets in the future. Any significant new generation approved by the Board of Directors and agreed to by the Shareholder may receive financial support from the Province of Ontario, if and as appropriate.

4.11 Subject to any unanimous shareholder declaration or resolution, OPG shall be permitted to participate in all energy-related procurements in Ontario.

4.12 OPG shall inform the Shareholder of any solar and wind developments or projects that the Corporation intends to undertake or assume, including the sources of the Corporation's financing, before undertaking or assuming such developments or projects.

4.13 Where appropriate, OPG shall pursue prospective generation related developments with First Nations and Métis communities that can provide the basis for long term mutually beneficial commercial arrangements.

4.14 Acknowledging sections 3.1 and 3.4 of this MOA, OPG will act in the interests of both OPG and the Shareholder in entering into potential settlements of material Aboriginal claims or grievances or material arrangements with communities potentially affected by OPG generation development. Unless otherwise agreed to with the Shareholder, OPG will pursue such agreements or arrangements so that the Shareholder benefits equally from releases from liability and indemnifications obtained by OPG in relation to damage caused by the construction, operation and development of OPG facilities. Nothing in this MOA will require OPG to pursue releases for matters for which the Shareholder may be solely liable.

5 REPORTING REQUIREMENTS

5.1 OPG and the Shareholder will ensure timely sharing of information sharing on major developments and issues that may impact the business of OPG or the interests of the Shareholder. Major developments and issues include planned acquisition of energy assets and/or assumption of existing power supply contracts, proposed settlements of material Aboriginal peoples' claims or grievances relating to OPG facilities, and proposed arrangements with communities affected by OPG generation development.

5.2 OPG shall report to the Shareholder, on an immediate basis, where a material human safety or system reliability issue arises.

5.3 Every year OPG shall develop and submit a rolling 3-5 year business plan to the Shareholder for review and concurrence.

a. Once approved by OPG's Board of Directors, OPG's annual business plan will be submitted to the Minister for concurrence.

b. The annual business plan shall include 3 -5 year performance targets based on operating and financial results as well as major project execution. It shall also include a 3 - 5 year investment plan for new projects.

c. OPG shall include objectives for operational efficiency improvements in its business plan.

d. Staff from the Ministry will review OPG's annual business plan in a timely manner.

e. The Deputy Minister shall advise and assist the Minister on any responsibilities associated with the approval of OPG's annual business plan.

f. OPG shall respond to any comments or requests for further information on the annual business plan, made by the Minister, Deputy Minister or Ministry staff in a timely manner.

g. Concurrence will be subject to the appearance of OPG's business plan before Treasury Board.

5.4 Within 90 days after the end of each fiscal year, as required by subsection of 53.4 (1) of the EA, OPG shall submit to the Minister an annual report on its affairs during that fiscal year.

a. In a timely manner in advance of the submission of the annual report to the Minister, OPG will provide a draft copy of the annual report for Ministry staff to review.

b. Ministry staff will review the draft annual report in a timely manner, and may request additional information from OPG, as necessary.

5.5 OPG shall provide, in a timely manner, quarterly and year-end financial reports for the Ministry's review prior to filing with the OSC, and in particular:

a. year-end financials, which include News Release, MD&A and Audited Financial Statements whose content is prescribed by the securities regulators' National Instrument 51-102; and,

b. the Annual Information Form and Statement of Executive Compensation, whose content is prescribed by securities regulators' National Instrument NI 51-102.

5.6 OPG shall provide briefings to senior officials of the Ministry on OPG's operational and financial performance against plan.

5.7 OPG shall provide reports and information to the Ministry of Finance, as required, from time to time, as per subsection 53.4 (4) of the EA. Reports and information requests from the Ministry of Finance shall be made through the Ministry of Energy.

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

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

6 PERFORMANCE EXPECTATIONS

6.1 Operational Expectations

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

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

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

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

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

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

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

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

c. This list shall be reviewed by OPG annually.

6.1.7 OPG shall support the province of Ontario in implementing its policy of putting conservation first by pursuing energy efficiency improvements in its operations where economic. OPG shall identify a lead for reporting on its energy efficiency improvements to liaise with the Ministry on a regular basis.

OPG shall also continue to report on its energy efficiency results in its annual Sustainable Development Report.

6.2 Financial Expectations

6.2.1 As an OBCA Corporation and reporting issuer with a commercial mandate, OPG shall operate on a financially sustainable basis, earning a commercial rate of return in order to be able to service its current and future liabilities, to support the appropriate level of capital spending and to maintain or increase the value of its assets for its Shareholder.

6.2.2 OPG shall finance project investments and its operations in a prudent and cost-effective manner.

6.3 Compensation

6.3.1 OPG shall annually inform the Shareholder about its compliance with applicable legislation and regulations governing employee compensation.

7 LABOUR NEGOTIATIONS

7.1 In advance of commencing discussions for the renewal of its collective agreements with its unions, OPG shall seek advice from the Ministry on Provincial policy direction and relevant fiscal considerations affecting labour negotiations in the broader public and/or energy sectors.

7.2 When a collective agreement has been negotiated and ratified, OPG shall inform the Ministry of the results and details of the collective agreement in a timely manner.

8 COMMUNICATIONS

8.1 The OPG Board of Directors and the Minister shall meet as needed to enhance mutual understanding of interrelated strategic matters.

8.2 OPG's Board Chair, OPG's President and Chief Executive Officer and the Minister shall meet on an as needed basis.

8.3 OPG's President and Chief Executive Officer and the Deputy Minister shall meet on a regular and as needed basis on matters of mutual importance.

8.4 OPG's senior management and Ministry senior officials shall meet on a regular and as needed basis to discuss new and ongoing issues, discuss strategic business objectives and OPG's performance, and to clarify expectations or to address emergent issues.

8.5 The Shareholder shall specifically seek OPG's input on electricity policies that may impact OPG, when and as appropriate.

8.6 OPG's communications shall include promotion and awareness of electricity generation and efficiency where appropriate to increase public understanding of energy consumption and support the Ministry's efforts.

8.7 OPG shall consult with the Ministry, as appropriate, on key communication issues that may affect the Ministry or OPG. OPG shall keep the Ministry informed, as appropriate, of the key communication issues in a timely manner, and in advance if it is possible or appropriate to do so, having regard to the seriousness of the key communication issue.

8.8 In all other respects, OPG shall communicate with government ministries and agencies in a manner typical for an Ontario Corporation of its size and scope to ensure a timely flow of information.

9 TERM OF THIS AGREEMENT

9.1 The MOA shall be in effect for not more than five years from the date of execution.

9.2 The Shareholder and the OPG Board Chair shall renew or revise this MOA by the expiry date, or earlier, as required.

9.3 The Shareholder and the OPG Board Chair shall reaffirm this MOA for continuance with a change in either the Minister or Chair, and such reaffirmation may be done by letter and such letter shall be considered part and parcel of this Agreement as if the party or parties reaffirming the MOA had duly signed and executed an amendment to the MOA.

9.4 This MOA shall be posted publicly on OPG's website.

SIGNATURES

Original signed by:	2015/05/20
________________________	_______________
Bernard Lord Board Chair Ontario Power Generation, Inc.	Date
Original signed by:	2015/07/17
________________________	_______________
Honourable Bob Chiarelli Minister of Energy	Date

APPENDIX 1: STATUTES OF PARTICULAR APPLICATION

Auditor General Act
Broader Public Sector Accountability Act, 2010
Business Corporations Act
Electricity Act, 1998
Freedom of Information and Protection of Privacy Act
Ontario Energy Board Act, 1998
Public Sector Compensation Restraint to Protect Public Services Act, 2010
Public Sector Expenses Review Act, 2009
Public Sector Salary Disclosure Act, 1996
Public Sector and MPP Accountability and Transparency Act, 2014

APPENDIX 2: APPLICABLE TB/MBC/MOF DIRECTIVES

Compensation Arrangements Compliance Report Directive
Perquisites Directive
Procurement Directive
Travel, Meal and Hospitality Directive
Ministers' Staff Commercial Transactions Directive

SCHEDULE D

DECISION AND ORDER

ONTARIO POWER GENERATION INC.

EB-2016-0152

DECEMBER 28, 2017

APPROVALS

In this Application, OPG seeks the following specific approvals:

Revenue Requirement

1. The approval of the following revenue requirements for the nuclear facilities, net of the nuclear stretch factor, as set out in Ex. I1-1-1 and amended by Ex. N1-1-1 and Ex. N2-1-1:

Period	Revenue Requirement
January 1, 2017 through December 31, 2017	$3,161.4M
January 1, 2018 through December 31, 2018	$3,185.7M
January 1, 2019 through December 31, 2019	$3,273.2M
January 1, 2020 through December 31, 2020	$3,783.5M
January 1, 2021 through December 31, 2021	$3,397.8M

Rate Base

2. The approval of the following rate bases for the nuclear facilities, as summarized in Ex. B1-1-1 and amended by Ex. N1-1-1 and Ex. N2-1-1:

Year	Rate Base
2017	$3,627.9M
2018	$3,606.9M
2019	$3,476.2M
2020	$7,453.8M
2021	$7,887.0M

Production Forecasts

3. Approval of the following production forecasts for the nuclear facilities, as presented in Ex. E2-1-1.

Year	Production Forecast (TWh)
2017	38.1
2018	38.5
2019	39.0
2020	37.4
2021	35.4

Cost of Capital

4. Approval of a deemed capital structure of 51 per cent debt and 49 per cent equity and a combined rate of return on rate base to be determined using data available for the three months prior to the effective date of the payment amounts order, in accordance with the OEB's Cost of Capital Report, and currently set by the OEB at 8.78 per cent for 2017 and adjusted annually using the prevailing rate of return on equity specified by the OEB, as presented in Ex. C1-1-1 and amended by Ex. N1-1-1.

Payment Amounts

5. Effective January 1, 2017, $41.71/MWh for the average hourly net energy production (MWh) from the regulated hydroelectric facilities in any given month (the "hourly volume") for each hour of that month. Where production is over or under the hourly volume, regulated hydroelectric incentive revenue payments will be consistent with the OEB's Payment Amounts Order in EB-2013-0321. The calculation of the payment amount for the regulated hydroelectric facilities is set out in Ex. I1-2-1.

6. Approval of the rate-setting formula and related elements for setting payment amounts for the prescribed hydroelectric generating facilities in the period from January 1, 2017 through December 31, 2021, as proposed in Ex. A1-3-2.

7. Approval of the following payment amounts for the nuclear facilities:

Effective Date	Payment Amount
January 1, 2017	$76.39/MWh
January 1, 2018	$78.60/MWh
January 1, 2019	$84.83/MWh
January 1, 2020	$88.21/MWh
January 1, 2021	$92.02/MWh

<u>Rate Smoothing and Mid-term Production Review</u>

8. Approval of the nuclear rate smoothing proposal as set out in Ex. A1-3-3 and amended by Ex. N1-1-1 and Ex. N2-1-1, including the establishment of a rate smoothing deferral account and the portion of the approved nuclear revenue requirement that is to be recorded in that deferral account. Specifically, OPG proposes that annual OPG weighted average payment amounts (as defined by O. Reg. 53/05, s. 0.1(1)) reflect a constant 2.5% per year rate increase during the 2017 to 2021 period resulting in a deferred nuclear revenue requirement of $251M, $162M, $(38)M, $488M, and $142M in 2017, 2018, 2019, 2020 and 2021, respectively.

9. Approval of a mid-term production review in the first half of 2019 (i.e., prior to July 1, 2019) for:
    i. an update of the nuclear production forecast and consequential updates to nuclear fuel costs for the final two-and-a-half years of the five-year application period (July 1, 2019 to December 31, 2021); and
    ii. disposal of applicable audited deferral and variance account balances as well as any remaining unamortized portions of previously approved amounts with recovery period extending beyond December 31, 2018.

<u>Deferral and Variance Accounts</u>

10. Approval for recovery of the audited December 31, 2015 balances of the deferral and variance accounts identified in Exhibit H.

11. Approval to continue existing deferral and variance accounts, including interest, as proposed in Ex. H1-1-1.

12. Approval of a hydroelectric payment rider to recover the approved balances of the hydroelectric deferral and variance accounts (except the Pension & OPEB Cash Versus Accrual Differential Deferral Account) at a rate of $1.44/MWh applied to the output from the hydroelectric facilities, beginning January 1, 2017 and terminating December 31, 2018.

13. Approval of a nuclear payment rider to recover the approved balances of the nuclear deferral and variance accounts (except the Pension & OPEB Cash Versus Accrual Differential Deferral Account) at a rate of $2.85/MWh applied to the output from the nuclear facilities, beginning January 1, 2017 and terminating December 31, 2018.

14. Approval to establish the following deferral and variance accounts as described in Ex. H1-1-1:
    i. Darlington Refurbishment Rate Smoothing Deferral Account;
    ii. Mid-term Nuclear Production Variance Account;
    iii. Nuclear ROE Variance Account; and
    iv. Hydroelectric Capital Structure Variance Account.

<u>Project Approvals</u>

15. OPG seeks the following approvals for the Darlington Refurbishment Program:
    i. In-service additions to rate base of: (i) $350.4M in the 2016 Bridge Year; and (ii) for the 2017-2021 period, $8.5M in 2017, $8.9M in 2018, $4,809.2M in 2020, and $0.4M in 2021 on a forecast basis. These amounts reflect the addition to rate base of $4,800.2M related to Unit 2 in-service addition in 2020 and 2021, as well as $377.2M related to Unit Refurbishment Early In-Service Projects, Safety Improvement Opportunities, and Facilities & Infrastructure Projects. If actual additions to rate base are different from

forecast amounts, the cost impact of the difference will be recorded in the Capacity Refurbishment Variance Account ("CRVA") and any amounts greater than the forecast amounts added to rate base will be subject to a prudence review in a future proceeding; and

ii. OM&A expenditures of $41.5M in 2017, $13.8M in 2018, $3.5M in 2019, $48.4M in 2020, and $19.7M in 2021 (Ex. F2-7-1).

Interim Payment Amounts

16. An order from the OEB declaring OPG's current payment amounts for regulated hydroelectric and nuclear facilities interim as of January 1, 2017, if the order or orders approving the payment amounts are not implemented by January 1, 2017.

SCHEDULE E

DECISION AND ORDER

ONTARIO POWER GENERATION INC.

EB-2016-0152

DECEMBER 28, 2017

PROCEDURAL DETAILS INCLUDING LISTS OF PARTIES AND WITNESSES

THE PROCEEDING

OPG filed its application for new payment amounts on May 27, 2016. On June 29, 2016, the OEB issued a Notice of Application which was published in accordance with the OEB's direction.

The key milestones in the proceeding are listed below:

- Procedural Order No.1 was issued on August 12, 2016. The procedural order set out dates for all procedural events up to and including the oral hearing. Procedural Order No. 1 also provided a draft issues list and made provision for submissions on issues and OPG's request for confidential treatment of certain information.
- An application presentation was held on September 1, 2016, and an untranscribed technical conference relating to the Darlington Refurbishment Program (DRP) and rate smoothing was held on September 23, 2016.
- The final unprioritized issues list was issued on September 23, 2016.
- Interrogatories were filed by Board staff on September 26, 2016 and by intervenors on October 3, 2016. The majority of responses were filed on October 26, 2016.
- A technical conference was held November 14 to 16, 2016.
- OEB staff filed evidence relating to DRP on November 21, 2016, and relating to Hydroelectric IRM Design and Equity Ratio on November 23, 2016.
- A motion hearing was held on December 16, 2016.
- Impact statements were filed on December 20, 2016 (to update the application to reflect material changes in costs), February 22, 2017 (to exclude in service additions related to two projects) and March 8, 2017 (revised smoothing proposal).
- The prioritized issues list was issued on December 21, 2016, and re-issued on January 27, 2017 with a single issue re-prioritized.
- A settlement conference was held January 9 to 11, 2017. Partial settlement was achieved. The settlement proposal was filed January 30, 3017, presented on March 6, 2017 and accepted by the OEB on March 20, 2017.
- Supplemental evidence was filed on February 14, 2017 (2017 ONFA Reference Plan) and April 4, 2017 (Hydroelectric Capacity Refurbishment Variance Account).
- The oral hearing took place on 23 days during the period February 27, 2017 to April 13, 2017.
- OPG filed its Argument-in-Chief on May 3, 3017.
- OEB staff filed its submission on May 19, 2017 and intervenors filed their submissions on May 29, 2017.
- OPG's reply argument was filed on June 19, 2017.

Nine procedural orders were issued during the course of the proceeding, some dealing with the schedule of the proceeding and prioritization of the issues list, but many dealing with matters of confidentiality, including submissions and decisions on requests for confidential treatment of documents.

PARTICIPANTS

Below is a list of participants and their representatives that were active either at the oral hearing or at another stage of the proceeding.

Ontario Power Generation Inc.	Charles Keizer Crawford Smith John Beauchamp Chris Fralick Barb Reuber
OEB Counsel and Staff	Michael Millar Ian Richler Violet Binette Rudra Mukherji Jane Scott Lawrie Gluck Keith Ritchie Donna Kwan Mark Rozic
Association of Major Power Consumers in Ontario	Ian Mondrow Shelley Grice Raymond Lukosius
Canadian Manufacturers & Exporters	Vince DeRose Emma Blanchard Scott Pollock
Consumers Council of Canada	Michael Buonaguro Julie Girvan
Energy Probe Research Foundation	Brady Yauch Lawrence Schwartz
Environmental Defence Canada Inc.	Kent Elson
Green Energy Coalition	David Poch Shawn-Patrick Stensil

London Property Management Association	Randy Aiken
Ontario Association of Physical Plant Administrators	Scott Walker
Power Workers' Union	Richard Stephenson Bayu Kidane Andrew Blair
Quinte Manufacturers Association	Michael McLeod
School Energy Coalition	Jay Shepherd Mark Rubenstein
Society of Energy Professionals	Bohdan Dumka
Sustainability-Journal	Ron Tolmie
Vulnerable Energy Consumers Coalition	Cynthia Khoo Lawrence Booth Mark Garner

In addition to the above, Canadian Wind Energy Association/Canadian Solar Industries Association, Candu Energy Inc., Lake Ontario Waterkeeper, Shell Energy North America (Canada) Inc. and SNC-Lavalin Nuclear Inc./Aecon Construction Group Inc. were registered intervenors in this proceeding.

WITNESSES

The following OPG employees appeared as witnesses.

Jeff Lyash	President and CEO
Dietmar Reiner	Senior Vice President, Nuclear Projects
Gary Rose	Vice President, Planning and Project Controls, Nuclear Projects
Leo Saagi	Director Controllership, Nuclear Projects
Chris Fralick	Vice President, Regulatory Affairs
Randy Pugh	Director, Ontario Regulatory Affairs, Regulatory Accounting and Finance

John Mauti	Vice President, Chief Controller & Accounting Officer
John Blazanin	Vice President, Nuclear Finance
Carla Carmichael	Vice President, Project Assurance and Contract Management, Nuclear Projects
Jamie Lawrie	Project Director
Jeff Lehman	Director Station Engineering
Bill Owens	Vice President, Refurbishment Execution
Alex Kogan	Vice President, Business Planning & Reporting
Dave Milton	Vice President Health, Safety, Employee and Labour Relations
Donna Rees	Director, Total Rewards
Lindsay Arseneau	Manager, Regulatory Affairs

OPG called the following expert witnesses: Patricia Galloway of Pegasus Global Holdings, Inc., Julia Frayer of London Economics International LLC, and James Coyne and Daniel Dane of Concentric Energy Advisors, Inc.

Andrew Pietrewicz of the Independent Electricity System Operator also appeared as a witness.

OEB staff called the following expert witnesses: Kenneth Roberts of Schiff Hardin LLP, Mark Lowry of Pacific Economics Group Research LLC and Bente Villadesen of the Brattle Group, Inc.

SCHEDULE F

DECISION AND ORDER

ONTARIO POWER GENERATION INC.

EB-2016-0152

DECEMBER 28, 2017

Ontario Power Generation Inc.
2017-2021 Payment Amounts for
Prescribed Generating Facilities
EB-2016-0152

FINAL ISSUES LIST (REPRIORITIZED)

1. GENERAL

1.1 Secondary: Has OPG responded appropriately to all relevant OEB directions from previous proceedings?
1.2 Primary: Are OPG's economic and business planning assumptions appropriate that impact the nuclear facilities appropriate?
1.3 Oral Hearing: Is the overall increase in nuclear payment amounts including rate riders reasonable given the overall bill impact on customers?

2. RATE BASE

2.1 Primary: Are the amounts proposed for nuclear rate base (excluding those for the Darlington Refurbishment Program) appropriate?
2.2 Oral Hearing: Are the amounts proposed for nuclear rate base for the Darlington Refurbishment Program appropriate?

3. CAPITAL STRUCTURE AND COST OF CAPITAL

3.1 Primary: Are OPG's proposed capital structure and rate of return on equity appropriate?
3.2 Secondary: Are OPG's proposed costs for the long-term and short-term debt components of its capital structure appropriate?

4. CAPITAL PROJECTS

4.1 Oral Hearing: 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?
4.2 Primary: Are the proposed nuclear capital expenditures and/or financial commitments (excluding those for the Darlington Refurbishment Program) reasonable?

4.3 Oral Hearing: Are the proposed nuclear capital expenditures and/or financial commitments for the Darlington Refurbishment Program reasonable?
4.4 Primary: Are the proposed test period in-service additions for nuclear projects (excluding those for the Darlington Refurbishment Program) appropriate?
4.5 Oral Hearing: Are the proposed test period in-service additions for the Darlington Refurbishment Program appropriate?

5. PRODUCTION FORECASTS

5.1 Primary: Is the proposed nuclear production forecast appropriate?

6. OPERATING COSTS

6.1 Oral Hearing: Is the test period Operations, Maintenance and Administration budget for the nuclear facilities (excluding that for the Darlington Refurbishment Program) appropriate?
6.2 Oral Hearing: Is the nuclear benchmarking methodology reasonable? Are the benchmarking results and targets flowing from OPG’s nuclear benchmarking reasonable?
6.3 Secondary: Is the forecast of nuclear fuel costs appropriate?
6.4 Oral Hearing: Is the test period Operations, Maintenance and Administration budget for the Darlington Refurbishment Program appropriate?
6.5 Oral Hearing: Are the test period expenditures related to extended operations for Pickering appropriate?

Corporate Costs

6.6 Oral Hearing: Are the test period human resource related costs for the nuclear facilities (including wages, salaries, payments under contractual work arrangements, benefits, incentive payments, overtime, FTEs and pension costs, etc.) appropriate?
6.7 Oral Hearing: Are the corporate costs allocated to the nuclear business appropriate?
6.8 Oral Hearing: Are the centrally held costs allocated to the nuclear business appropriate?

Depreciation

6.9 Primary: Is the proposed test period nuclear depreciation expense appropriate?

Income and Property Taxes

6.10 Primary: Are the amounts proposed to be included in the test period nuclear revenue requirement for income and property taxes appropriate?

Other Costs

6.11 Secondary: Are the asset service fee amounts charged to the nuclear business appropriate?

7. OTHER REVENUES

Nuclear

7.1 Secondary: Are the forecasts of nuclear business non-energy revenues appropriate?

Bruce Nuclear Generating Station

7.2 Primary: Are the test period costs related to the Bruce Nuclear Generating Station, and costs and revenues related to the Bruce lease appropriate?

8. NUCLEAR WASTE MANAGEMENT AND DECOMMISSIONING LIABILITIES

8.1 Primary (reprioritized): Is the revenue requirement methodology for recovering nuclear liabilities in relation to nuclear waste management and decommissioning costs appropriate? If not, what alternative methodology should be considered?

8.2 Primary: Is the revenue requirement impact of the nuclear liabilities appropriately determined?

9. DEFERRAL AND VARIANCE ACCOUNTS

9.1 Primary: Is the nature or type of costs recorded in the deferral and variance accounts appropriate?

9.2 Primary: Are the methodologies for recording costs in the deferral and variance accounts appropriate?

9.3 Secondary: Are the balances for recovery in each of the deferral and variance accounts appropriate?
9.4 Secondary: Are the proposed disposition amounts appropriate?
9.5 Primary: Is the disposition methodology appropriate?
9.6 Secondary: Is the proposed continuation of deferral and variance accounts appropriate?
9.7 Primary: Is the rate smoothing deferral account in respect of the nuclear facilities that OPG proposes to establish consistent with O. Reg. 53/05 and appropriate?
9.8 Primary: Should any newly proposed deferral and variance accounts be approved by the OEB?

10. REPORTING AND RECORD KEEPING REQUIREMENTS

10.1 Secondary: Are the proposed reporting and record keeping requirements appropriate?
10.2 Primary: Is the monitoring and reporting of performance proposed by OPG for the regulated hydroelectric facilities appropriate?
10.3 Primary: Is the monitoring and reporting of performance proposed by OPG for the nuclear facilities appropriate?
10.4 Oral Hearing: Is the proposed reporting for the Darlington Refurbishment Program appropriate?

11. METHODOLOGIES FOR SETTING PAYMENT AMOUNTS

Hydroelectric

11.1 Oral Hearing: Is OPG's approach to incentive rate-setting for establishing the regulated hydroelectric payment amounts appropriate?
11.2 Secondary: Are the adjustments OPG has made to the regulated hydroelectric payment amounts arising from EB-2013-0321 appropriate for establishing base rates for applying the hydroelectric incentive regulation mechanism?

Nuclear

11.3 Oral Hearing: Is OPG's approach to incentive rate-setting for establishing the nuclear payment amounts appropriate?
11.4 Oral Hearing: Does the Custom IR application adequately include expectations for productivity and efficiency gains relative to benchmarks and establish an appropriately structured incentive-based rate framework?

11.5 Primary: Is OPG’s proposed mid-term review appropriate?
11.6 Oral Hearing: Is OPG’s proposal for smoothing nuclear payment amounts consistent with O. Reg. 53/05 and appropriate?

General

11.7 Primary: Is OPG’s proposed off-ramp appropriate?

12. IMPLEMENTATION

12.1 Primary: Are the effective dates for new payment amounts and riders appropriate?

SCHEDULE G

DECISION AND ORDER

ONTARIO POWER GENERATION INC.

EB-2016-0152

DECEMBER 28, 2017

SETTLEMENT PROPOSAL

Ontario Power Generation Inc.

Application for 2017-2021 Payment Amounts
for Prescribed Generation Facilities

EB-2016-0152

March 6, 2017

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Ontario Power Generation Inc.
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SETTLEMENT PROPOSAL

A. PREAMBLE

This Settlement Proposal is filed with the Ontario Energy Board (the "OEB") in connection with an application by Ontario Power Generation Inc. ("OPG") for an order or orders approving payment amounts for prescribed generation facilities commencing January 1, 2017 (the "Application").

Pursuant to the OEB's Procedural Order No. 1 dated August 12, 2016, a Settlement Conference was scheduled to be held commencing January 9, 2017. The settlement discussions were held at the OEB's offices from January 9 to 11, 2017, in a manner consistent with the process contemplated by the OEB's *Practice Direction on Settlement Conferences* (the "Practice Direction").

The Parties

OPG and the following intervenors (the "Intervenors", and, collectively with OPG, the "Parties"), participated in the Settlement Conference:

- Association of Major Power Consumers in Ontario ("AMPCO")
- Canadian Manufacturers & Exporters ("CME")
- Consumers Council of Canada ("CCC")
- Environmental Defence ("ED")
- Energy Probe Research Foundation ("EP")
- Green Energy Coalition ("GEC")
- London Property Management Association ("LPMA")
- Ontario Association of Physical Plant Administrators ("OAPPA")
- Power Workers' Union ("PWU")
- Quinte Manufacturers Association ("QMA")
- School Energy Coalition ("SEC")
- Society of Energy Professionals ("Society")
- Sustainability-Journal.ca ("SJ")
- Vulnerable Energy Consumers Coalition ("VECC")

OEB staff also participated in the settlement discussions, but in accordance with the Practice Direction is neither a Party nor a signatory to this Settlement Proposal. Although OEB Staff is not a Party to this Settlement Proposal, OEB Staff who did participate in the settlement discussions are bound by the same confidentiality provisions that apply to the Parties to the proceeding.

This document is called a "Settlement Proposal" because it is proposed by the Parties to the OEB to settle certain issues in this proceeding. It is termed a proposal as between the Parties and the OEB. However, as between the Parties, and subject only to the OEB's approval of this Settlement Proposal, this document is intended to be a legal agreement, creating mutual rights and obligations, and to be binding and enforceable in accordance with its terms. As set forth later in the Preamble, this agreement is subject to a condition subsequent, that if this Settlement Proposal is not accepted by the OEB in its entirety, then, unless amended by the Parties, it is null and void and of no further effect. In entering this agreement, the Parties understand and agree that, pursuant to the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15 (Schedule B) (the "Act") the OEB has the exclusive jurisdiction with respect to the interpretation and enforcement of the terms hereof.

Confidentiality

The Parties agree that the settlement discussions shall be subject to the rules relating to confidentiality and privilege contained in the Practice Direction, as amended on October 28, 2016. The Parties understand that confidentiality in that context does not have the same meaning as confidentiality in the OEB's *Practice Direction on Confidential Filings*, and the rules of that latter document do not apply. The Parties interpret the revised Practice Direction to mean that the documents and other information provided, the discussion of each issue, the offers and counter-offers, and the negotiations leading to settlement – or not – of each issue during the course of the settlement discussions are strictly confidential and without prejudice. None of the foregoing is admissible as evidence in this proceeding, or otherwise, except where the filing of such settlement information is necessary to resolve a subsequent dispute over the interpretation of any provision of this Settlement Proposal and subject to the direction of the OEB. In such case, only the settlement information that is necessary for the purpose of interpreting the Settlement Proposal shall be filed and such information shall be filed using the appropriate protections afforded under the relevant legislation and OEB instruments.

Further, the Parties have a positive and ongoing obligation not to disclose settlement information to persons who were not attendees at the settlement conference. However, the Parties agree that "attendees" is deemed to include, in this context, persons who were not physically in attendance at the settlement conference but were: (a) any persons or entities that the Parties engage to assist them with the settlement conference; and (b) any persons or entities from whom the Parties seek instructions with respect to the negotiations; in each case provided that any such persons or entities have agreed to be bound by the same confidentiality provisions.

Parameters of the Proposed Settlement

Without prejudice to the positions of the Parties with respect to issues that might otherwise be considered in this proceeding, the Parties have organized this Settlement Proposal in a manner that is consistent with the Final Prioritized Issues List as set out in Schedule ‘A’ of the OEB’s Decision on Issues List Prioritization dated December 21, 2016, which categorizes the issues as “Primary”, “Secondary”, or “Oral Hearing”.

The Parties are pleased to inform the OEB that the Parties have reached agreement to settle, in full or in part, nine of the issues, including two Primary issues and seven Secondary issues. If the Settlement Proposal is accepted by the OEB, the Parties will not adduce any evidence or argument during the hearing on any of the issues or aspects of the issues on which Parties have reached agreement, as the Parties have agreed to the proposed settlement.

The Settlement Proposal describes the agreements reached on the settled and partially settled issues, and identifies the Parties who agree or who take no position on each issue. For each issue, the Settlement Proposal provides a direct reference to the supporting evidence on the record to date. In this regard, the Parties are of the view that the evidence provided is sufficient to support the Settlement Proposal in relation to such settled or partially settled issue, and moreover, that the quality and detail of the supporting evidence, together with the corresponding rationale, should allow the OEB to make findings on these issues.

Best efforts have been made to identify all of the evidence that relates to each settled or partially settled issue. The supporting evidence is identified individually by reference to its exhibit number in an abbreviated format such that, for example, Exhibit A4, Tab 1, Schedule 1 will be referred to as Ex. A4-1-1. In this regard, OPG’s response to an interrogatory (“IR”) is described by citing the issue number, name of the Party and the number of the IR (e.g. L-3.2-1 Staff-22). The identification and listing of the evidence that relates to each issue is provided to assist the OEB. The identification and listing of the evidence that relates to each settled or partially settled issue is not intended to limit any Party who wishes to assert, either in any other proceeding, or in a hearing in this proceeding, that other evidence is relevant to a particular settled or partially settled issue, that evidence listed is not relevant to the issue, or that evidence listed is also relevant to other issues.

According to the Practice Direction (p. 4), the Parties must consider whether a Settlement Proposal should include an appropriate adjustment mechanism for any settled issue that may be affected by external factors. OPG and the other Parties who participated in the settlement discussions agree that no settled or partially settled issue requires an adjustment mechanism other than as may be expressly set forth herein.

All of the issues contained in this proposal have been settled or partially settled by the Parties as a package and none of the provisions of these are severable. Numerous compromises were made by the Parties with respect to various matters to arrive at this Settlement Proposal. The distinct issues addressed in this proposal are intricately interrelated, and reductions or increases to the agreed-upon amounts or changes in other agreed-upon parameters may have consequences in other areas of this proposal, which may be unacceptable to one or more of the Parties. If the OEB does not accept this package in its entirety, then there is no settlement (unless the Parties agree that any portion of the package that the OEB does accept may continue as part of a valid Settlement Proposal).

In the event the OEB directs the Parties to make reasonable efforts to revise the Settlement Proposal, the Parties agree to use reasonable efforts to discuss any potential revisions, but no party will be obligated to accept any proposed revision. The Parties agree that all of the Parties who took a position on a particular issue must agree with any revised Settlement Proposal as it relates to that issue prior to its re-submission to the OEB.

None of the Parties can withdraw from this Settlement Proposal except in accordance with Rule 30.05 of the OEB's *Rules of Practice and Procedure*.

Attached to this Settlement Proposal are:

Attachment 1: List of Existing OPG Deferral and Variance Accounts

Attachment 2: List of Settled, Partially Settled and Unsettled Issues

The Attachments to this Settlement Proposal provide further support for the Settlement Proposal. The Parties acknowledge that the Attachments were prepared by OPG. While the intervenors have reviewed the Attachments, the intervenors are relying upon their accuracy, and the accuracy of the underlying evidence, in entering into this Settlement Proposal.

Unless stated otherwise, the settlement of any particular issue in this proceeding and the positions of the Parties in this Settlement Proposal are without prejudice to the rights of the Parties to raise the same issue and/or to take any position thereon in any other proceeding, whether or not OPG is a party to such proceeding, provided that no Party shall take a position that would result in the agreement not applying in accordance with the terms contained herein.

Where in this agreement, the Parties "Accept" the evidence of OPG, or "agree" to a revised term or condition, including a revised budget or forecast, then unless the agreement expressly states to the contrary, the words "for the purpose of settlement of the issues herein" shall be deemed to qualify that acceptance or agreement.

Issues Fully or Partially Settled by the Parties

As shown below, the Parties have agreed to fully settle four issues and partially settle five issues in this proceeding. All other issues will proceed to hearing if the OEB accepts this Settlement Proposal.

Issue	Settled or Partially Settled
Capital Structure and Cost of Capital	
3.2 Secondary: Are OPG's proposed costs for the long-term and short term components of its capital structure appropriate?	Partially Settled
Operating Costs	
6.3 Secondary: Is the forecast of nuclear fuel costs appropriate?	Partially Settled
6.11 Secondary: Are the asset service fee amounts charged to the nuclear business appropriate?	Settled
Other Revenues – Nuclear	
7.1 Secondary: Are the forecasts of nuclear business non-energy revenues appropriate?	Settled
Deferral and Variance Accounts	
9.1 Primary: Is the nature or type of costs recorded in the deferral and variance accounts appropriate?	Partially Settled
9.2 Primary: Are the methodologies for recording costs in the deferral and variance accounts appropriate?	Partially Settled
9.3 Secondary: Are the balances for recovery in each of the deferral and variance accounts appropriate?	Partially Settled
9.6 Secondary: Is the proposed continuation of deferral and variance accounts appropriate?	Settled
Methodologies for Setting Payment Amounts	
11.2 Secondary: Are the adjustments OPG has made to the regulated hydroelectric payment amounts arising from EB-2013-0321 appropriate for establishing base rates for applying the hydroelectric incentive regulation mechanism?	Settled

Based on the foregoing, and the evidence and rationale provided below, the Parties accept this Settlement Proposal as appropriate and recommend its acceptance by the OEB.

B. Description of Settlement

Issue 3.2 Secondary: Are OPG's proposed costs for the long-term and short term components of its capital structure appropriate?

Partially Settled

There is an agreement to partially settle this issue as described below.

As indicated in Ex. C1-1-2 and Ex. C1-1-3, OPG seeks to recover the costs of long-term and short-term debt associated with its regulated operations during the IR term. The Parties agree that the assumed interest rates used to calculate OPG's proposed debt costs are appropriate on the basis of its written evidence, subject to the following:

- Given that the aggregate debt costs relate to OPG's capital structure and rate base, which are unsettled primary issues (see Issues 2.1, 2.2 and 3.1), the Parties agree that their acceptance in respect of Issue 3.2 is subject to the application of the agreed interest rates to the eventual debt financed component of rate base as determined by the OEB.

Approval

Parties in Support:	AMPCO, CME, CCC, EP, LPMA, OAPPA, QMA, SEC, Society, VECC
Parties Taking no Position:	ED, GEC, PWU, SJ

Evidence

The evidence in relation to this issue includes the following:

Ex. C1-1-2 Cost of Long-term Debt
Ex. C1-1-3 Cost of Short-term Debt
L-3.2-1 Staff-22
L-3.2-1 Staff-23
L-3.2-6 EP-5
L-3.2-6 EP-6
L-3.2-6 EP-8
L-3.2-11 LPMA-1
L-3.2-11 LPMA-2
L-3.2-11 LPMA-3
L-3.2-11 LPMA-4
L-3.2-20 VECC-12
L-3.2-20 VECC-13

Issue 6.3 Secondary: Is the forecast of nuclear fuel costs appropriate?
Partially Settled

There is an agreement to partially settle this issue as described below.

In the Application, OPG seeks to recover its proposed nuclear fuel costs for the IR term. The proposed fuel costs include the weighted average cost of manufactured uranium fuel bundles loaded into a reactor ("nuclear fuel bundle cost"), used nuclear fuel storage and disposal costs, and fuel oil costs. As indicated in Ex. F2-5-2, actual nuclear fuel bundle costs are driven by total energy production, unit cost of new fuel loaded, and fuel utilization efficiency.

A partial settlement has been reached on this issue. The Parties have agreed to a 2% downward adjustment to the nuclear fuel bundle unit cost forecast in each year of the IR term relative to the forecast in the Application at Ex. F2-5-1 Table 1, line 4, resulting in fuel bundle unit costs as follows:

- 2017: $4.18/MWh
- 2018: $4.14/MWh
- 2019: $4.07/MWh
- 2020: $4.39/MWh
- 2021: $4.19/MWh

The other components of OPG's fuel costs forecast, including the impact of forecast energy production on nuclear fuel bundle cost, all components of used nuclear fuel costs, and fuel oil costs, are unsettled.

Approval

Parties in Support:	AMPCO, CME, CCC, EP, LPMA, OAPPA, QMA, SEC, Society, VECC
Parties Taking no Position:	ED, GEC, PWU, SJ

Evidence

The evidence in relation to this issue includes the following:

Ex. F2-5-1 Nuclear Fuel Costs
Ex. F2-5-2 Comparison of Nuclear Fuel Costs
Ex. L-6.3-1 Staff-111
Ex. L-6.3-1 Staff-112
Ex. L-6.3-2 AMPCO-116
Ex. L-6.3-2 AMPCO-117
Ex. L-6.3-2 AMPCO-118

Ex. L-6.3-5 CCC-28
Ex. L-6.3-5 CCC-29
Ex. L-6.3-15 SEC-66
Ex. L-6.3-20 VECC-26
Ex. L-6.3-20 VECC-27
Ex. JT2.10
Ex. JT2.11
Ex. JT2.15

Issue 6.11 Secondary: Are the asset service fee amounts charged to the nuclear business appropriate?

Settled

There is an agreement to settle this issue as described below.

In the Application, OPG seeks to recover its proposed asset service fees for the IR term. The Parties agree that the proposed asset service fee amounts charged to the nuclear business are appropriate on the basis of OPG's evidence.

Approval

Parties in Support:	AMPCO, CME, CCC, EP, LPMA, OAPPA, QMA, SEC, Society, VECC
Parties Taking no Position:	ED, GEC, PWU, SJ

Evidence

The evidence in relation to this issue includes the following:

Ex. F3-2-1 Asset Service Fees
Ex. F3-2-2 Comparison of Asset Service Fees
L-6.11-1 Staff-197
L-6.11-1 Staff-198

Issue 7.1 Secondary: Are the forecasts of nuclear business non-energy revenues appropriate?

Settled

There is an agreement to settle this issue as described below.

As indicated in Ex. G2-1-1, OPG has forecasted the non-energy revenues to be derived from its nuclear operations during the IR term. The forecast amounts are included as an offset in the calculation of OPG's revenue requirement, adjusted for 50/50 sharing of forecasted net revenue from sales of heavy water between OPG and ratepayers, consistent with prior OPG payment amounts applications. The Parties have agreed that OPG's forecast amounts of nuclear non-energy revenues are appropriate, subject to the following increases to OPG's net revenue forecast for heavy water sales for each year of the IR term (totalling a $12.2M increase over the IR term), relative to the forecast in the Application at Ex. G2-1-1 Table 1, line 1:

- 2017: $6.1M
- 2018: $1.3M
- 2019: $1.5M
- 2020: $1.6M
- 2021: $1.7M

These amounts represent increases at 100% of net revenues for heavy water sales, prior to the 50/50 sharing arrangement.

Approval

Parties in Support:	AMPCO, CME, CCC, EP, LPMA, OAPPA, QMA, SEC, Society, VECC
Parties Taking no Position:	ED, GEC, PWU, SJ

Evidence

The evidence in relation to this issue includes the following:

Ex. G2-1-1 Non-Energy Revenues (Nuclear)
Ex. G2-1-2 Comparison of Non-Energy Revenues (Nuclear)
Ex. L-7.1-1 Staff-199
Ex. L-7.1-1 Staff-200
Ex. L-7.1-1 Staff-201
Ex. L-7.1-12 OAPPA-4
Ex. L-7.1-15 SEC-89
Ex. L-7.1-20 VECC-36
Ex. L-7.1-20 VECC-37
Ex. L-7.1-20 VECC-38

Issue 9.1 Primary: Is the nature or type of costs recorded in the deferral and variance accounts appropriate?

Partially Settled

There is an agreement to partially settle the issue as described below.

Ex. H1-1-1 describes OPG's deferral and variance accounts, which were established pursuant to O. Reg. 53/05 and to the OEB's decisions and orders in prior OPG payment amounts and other applications. The Parties agree that the nature and type of costs recorded in the year-end 2015 balances of deferral and variance accounts are appropriate on the basis of OPG's evidence, except for the following accounts which were excluded from the Parties' settlement on this issue:

- Capacity Refurbishment Variance Account (Nuclear);
- Nuclear Liability Deferral Account; and
- Bruce Lease Net Revenues Variance Account.

For ease of reference, a complete list of OPG's existing deferral and variance accounts is included in Attachment 1 to this Settlement Proposal.

Approval

Parties in Support:	AMPCO, CME, CCC, EP, LPMA, OAPPA, QMA, SEC, Society, VECC
Parties Taking no Position:	ED, GEC, PWU, SJ

Evidence

The evidence in relation to this issue includes the following:

Ex. H1-1-1 Deferral and Variance Accounts
L-9.1-1 Staff-209
L-9.1-2 AMPCO-151

Issue 9.2 Primary: Are the methodologies for recording costs in the deferral and variance accounts appropriate?

Partially Settled

There is an agreement to partially settle the issue as described below.

Ex. H1-1-1 discusses the methodologies that have been used to record entries into OPG's existing deferral and variance accounts to date and the proposed methodologies for making entries into the accounts proposed for continuation. The Parties agree that the methodologies used and proposed to be used by OPG for recording costs in the deferral and variance accounts to and including December 31, 2015 are appropriate on the basis of OPG's evidence, except for the following accounts which were excluded from the Parties' settlement on this issue:

- Capacity Refurbishment Variance Account (Nuclear);
- Nuclear Liability Deferral Account; and
- Bruce Lease Net Revenues Variance Account.

For ease of reference, a complete list of OPG's existing deferral and variance accounts is included in Attachment 1 to this Settlement Proposal.

Approval

Parties in Support:	AMPCO, CME, CCC, EP, LPMA, OAPPA, QMA, SEC, Society, VECC
Parties Taking no Position:	ED, GEC, PWU, SJ

Evidence

The evidence in relation to this issue includes the following:

Ex. H1-1-1	Deferral and Variance Accounts
L-9.2-1 Staff-212	
L-9.2-1 Staff-213	
Ex. JT3.14	

Issue 9.3 Secondary: Are the balances for recovery in each of the deferral and variance accounts appropriate?

Partially Settled

There is an agreement to partially settle the issue as described below.

In the Application, OPG requests recovery of the audited, year-end 2015 balances in the deferral and variance accounts, less 2016 amortization amounts approved in EB-2014-0370, through a hydroelectric payment rider and a nuclear payment rider. This request does not apply to the Pension & OPEB Cash Versus Accrual Differential Deferral Account, since the OEB indicated in the EB-2013-0321 Decision with Reasons that the clearance of that account is subject to the completion of the OEB's generic proceeding on pension and OPEB costs (EB-2015-0040). The relevant account balances are set out in Ex. H1-2-1 Table 1, col. (c) and Table 2, col. (c).

The Parties agree that the proposed year-end 2015 balances for recovery in each of the deferral and variance accounts are appropriate on the basis of OPG's evidence, except for (i) the Pension & OPEB Cash Versus Accrual Differential Deferral Account, for the reason noted above; and (ii) the following accounts which were excluded from the Parties' settlement on this issue:

- Capacity Refurbishment Variance Account (Nuclear component);
- Nuclear Liability Deferral Account; and
- Bruce Lease Net Revenues Variance Account.

For ease of reference, a complete list of OPG's existing deferral and variance accounts is included in Attachment 1 to this Settlement Proposal.

Approval

Parties in Support:	AMPCO, CME, CCC, EP, LPMA, OAPPA, QMA, SEC, Society, SJ, VECC
Parties Taking no Position:	ED, GEC, PWU

Evidence

The evidence in relation to this issue includes the following:

Ex. H1-1-1	Deferral and Variance Accounts
Ex. H1-2-1	Clearance of Deferral and Variance Accounts
L-9.3-1 Staff-214	

Issue 9.6 Secondary: Is the proposed continuation of deferral and variance accounts appropriate?

Settled

There is an agreement to settle the issue as described below.

In the Application, OPG seeks approval for the continuation of its existing deferral and variance accounts (including the proposed termination of the Pickering Life Extension Depreciation Variance Account as of the effective date of the payment amounts order in respect of this Application), as described in Ex. H1-1-1. The Parties agree that the proposed continuation of deferral and variance accounts is appropriate on the basis of OPG's evidence. Provided that, for greater certainty, agreement to continue the accounts is not intended to imply agreement with the existing or proposed methodology, entries, or other terms relating to those accounts that are excluded from the settlement of issues 9.1, 9.2, and 9.3.

For ease of reference, a complete list of OPG's existing deferral and variance accounts is included in Attachment 1 to this Settlement Proposal.

Approval

Parties in Support:	AMPCO, CME, CCC, EP, LPMA, OAPPA, QMA, SEC, Society, SJ, VECC
Parties Taking no Position:	ED, GEC, PWU

Evidence

The evidence in relation to this issue includes the following:

Ex. H1-1-1 Deferral and Variance Accounts

Issue 11.2 Secondary: Are the adjustments OPG has made to the regulated hydroelectric payment amounts arising from EB-2013-0321 appropriate for establishing base rates for applying the hydroelectric incentive regulation mechanism?

Settled

There is an agreement to settle the issue as described below.

In the Application, OPG proposes to use the current hydroelectric payment amounts as approved in EB-2013-0321 as the "going in" rates for the IR term, adjusted to correct for the one-time allocation of the nuclear tax loss to the hydroelectric business in the EB-2013-0321 payment amounts application.

Without prejudice to any position a Party may take in respect of Issue 11.1, the Parties agree that the tax-loss adjustment OPG made to the regulated hydroelectric payment amounts arising from EB-2013-0321 is an appropriate adjustment.

Approval

Parties in Support:	AMPCO, CME, CCC, EP, LPMA, OAPPA, QMA, SEC, Society, VECC
Parties Taking no Position:	ED, GEC, PWU, SJ

Evidence

The evidence in relation to this issue includes the following:

Ex. A1-3-2	Rate-setting Framework Section 2.3.2: "Going in" Rates
Ex. I1-2-1	Regulated Hydroelectric Payment Amount

Ex. L-11.2-1 Staff-253
Ex. L-11.2-1 Staff-254
Ex. L-11.2-5 CCC-48

ATTACHMENTS

Attachment 1

LIST OF EXISTING OPG DEFERRAL AND VARIANCE ACCOUNTS

- Hydroelectric Water Conditions Variance Account
- Ancillary Services Net Revenues Variance Account – Hydroelectric and Nuclear Sub-Accounts
- Hydroelectric Incentive Mechanism Variance Account
- Hydroelectric Surplus Baseload Generation Variance Account
- Income and Other Taxes Variance Account
- Capacity Refurbishment Variance Account[Note (a)]
- Pension and OPEB Cost Variance Account
- Hydroelectric Deferral and Variance Over/Under Recovery Variance Account
- Gross Revenue Charge Variance Account
- Pension & OPEB Cash Payment Variance Account
- Pension & OPEB Cash Versus Accrual Differential Deferral Account[Note (b)]
- Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account
- Nuclear Liability Deferral Account[Note (c)]
- Nuclear Development Variance Account
- Bruce Lease Net Revenues Variance Account – Derivative and Non-Derivative Sub-Accounts[Note (c)]
- Pickering Life Extension Depreciation Variance Account (proposed to be terminated as of the effective date of the payment amounts order of this Application)
- Nuclear Deferral and Variance Over/Under Recovery Variance Account
- Impact Resulting from Changes in Station End-of-Life Dates (December 31, 2015) Deferral Account

Note (a): Excluded from the scope of partial settlement on Issues 9.1 and 9.2. The Nuclear component of the CRVA is excluded from the scope of partial settlement on Issue 9.3.
Note (b): Excluded from the scope of partial settlement on Issue 9.3.
Note (c): Excluded from the scope of partial settlement on Issues 9.1, 9.2 and 9.3.

Attachment 2

LIST OF SETTLED, PARTIALLY SETTLED AND UNSETTLED ISSUES[1]

1. GENERAL

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

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

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

2. RATE BASE

2.1 Primary: Are the amounts proposed for nuclear rate base (excluding those for the Darlington Refurbishment Program) appropriate?

2.2 Oral Hearing: Are the amounts proposed for nuclear rate base for the Darlington Refurbishment Program appropriate?

3. CAPITAL STRUCTURE AND COST OF CAPITAL

3.1 Primary: Are OPG's proposed capital structure and rate of return on equity appropriate?

[Partially Settled] 3.2 <u>Secondary: Are OPG's proposed costs for the long-term and short-term debt components of its capital structure appropriate?</u>

4. CAPITAL PROJECTS

4.1 Oral Hearing: 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?

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

4.3 Oral Hearing: Are the proposed nuclear capital expenditures and/or

[1] Unless marked as "Settled" or "Partially Settled", an issue remains unsettled.

financial commitments for the Darlington Refurbishment Program reasonable?

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

4.5 Oral Hearing: Are the proposed test period in-service additions for the Darlington Refurbishment Program appropriate?

5. PRODUCTION FORECASTS

5.1 Primary: Is the proposed nuclear production forecast appropriate?

6. OPERATING COSTS

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

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

[Partially Settled]

6.3 Secondary: Is the forecast of nuclear fuel costs appropriate?

6.4 Oral Hearing: Is the test period Operations, Maintenance and Administration budget for the Darlington Refurbishment Program appropriate?

6.5 Oral Hearing: Are the test period expenditures related to extended operations for Pickering appropriate?

Corporate Costs

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

6.7 Oral Hearing: Are the corporate costs allocated to the nuclear business appropriate?

6.8 Oral Hearing: Are the centrally held costs allocated to the nuclear business appropriate?

Depreciation

6.9 Primary: Is the proposed test period nuclear depreciation expense appropriate?

Income and Property Taxes

6.10 Primary: Are the amounts proposed to be included in the test period nuclear revenue requirement for income and property taxes appropriate?

Other Costs

[Settled] 6.11 Secondary: Are the asset service fee amounts charged to the nuclear business appropriate?

7. OTHER REVENUES

Nuclear

[Settled] 7.1 Secondary: Are the forecasts of nuclear business non-energy revenues appropriate?

Bruce Nuclear Generating Station

7.2 Primary: Are the test period costs related to the Bruce Nuclear Generating Station, and costs and revenues related to the Bruce lease appropriate?

8. NUCLEAR WASTE MANAGEMENT AND DECOMMISSIONING LIABILITIES

8.1 Secondary: Is the revenue requirement methodology for recovering nuclear liabilities in relation to nuclear waste management and decommissioning costs appropriate? If not, what alternative methodology should be considered?

8.2 Primary: Is the revenue requirement impact of the nuclear liabilities appropriately determined?

9. DEFERRAL AND VARIANCE ACCOUNTS

[Partially 9.1 Primary: Is the nature or type of costs recorded in the deferral and variance

Settled] accounts appropriate?

[Partially Settled] 9.2 Primary: Are the methodologies for recording costs in the deferral and variance accounts appropriate?

[Partially Settled] 9.3 Secondary: Are the balances for recovery in each of the deferral and variance accounts appropriate?

9.4 Secondary: Are the proposed disposition amounts appropriate?

9.5 Primary: Is the disposition methodology appropriate?

[Settled] 9.6 Secondary: Is the proposed continuation of deferral and variance accounts appropriate?

9.7 Primary: Is the rate smoothing deferral account in respect of the nuclear facilities that OPG proposes to establish consistent with O. Reg. 53/05 and appropriate?

9.8 Primary: Should any newly proposed deferral and variance accounts be approved by the OEB?

10. REPORTING AND RECORD KEEPING REQUIREMENTS

10.1 Secondary: Are the proposed reporting and record keeping requirements appropriate?

10.2 Primary: Is the monitoring and reporting of performance proposed by OPG for the regulated hydroelectric facilities appropriate?

10.3 Primary: Is the monitoring and reporting of performance proposed by OPG for the nuclear facilities appropriate?

10.4 Oral Hearing: Is the proposed reporting for the Darlington Refurbishment Program appropriate?

11. METHODOLOGIES FOR SETTING PAYMENT AMOUNTS

Hydroelectric

11.1 Oral Hearing: Is OPG's approach to incentive rate-setting for establishing the regulated hydroelectric payment amounts appropriate?

[Settled] 11.2 Secondary: Are the adjustments OPG has made to the regulated hydroelectric payment amounts arising from EB-2013-0321 appropriate for establishing base rates for applying the hydroelectric incentive regulation mechanism?

Nuclear

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

11.4 Oral Hearing: Does the Custom IR application adequately include expectations for productivity and efficiency gains relative to benchmarks and establish an appropriately structured incentive-based rate framework?

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

11.6 Oral Hearing: Is OPG's proposal for smoothing nuclear payment amounts consistent with O. Reg. 53/05 and appropriate?

General

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

12. IMPLEMENTATION

12.1 Primary: Are the effective dates for new payment amounts and riders appropriate?

SCHEDULE H

DECISION AND ORDER

ONTARIO POWER GENERATION INC.

EB-2016-0152

DECEMBER 28, 2017

2018 Input Price Index for OPG's Prescribed Hydroelectric Price Cap IR Plan

Year	Inputs and Assumptions											
	Non-Labour GDP-IPI (FDD) - National							Labour AWE - All Employees - Ontario			Resultant Values - Annual Growth for the 2-factor IPI	
	Q1	Q2	Q3	Q4	Annual	Annual % Change	Weight	Annual	Annual % Change	Weight	Annual	Annual % Change
2015	114.6	115	115.7	116.1	115.35			$ 962.94			103.7	
2016	116.4	116.3	116.8	117.5	116.750	**1.2%**	**88%**	$ 973.56	**1.1%**	**12%**	**104.9**	**1.2%**

Sources:

- GDP-IPI (FDD): Statistics Canada, Table 380-0066 - Price Indexes, gross domestic product, quarterly (2007 = 100 unless otherwise noted) - 2016 Q2, issued August 31, 2017

- Average Weekly Earnings (AWE): Statistics Canada, Table 281-0027 - Average weekly earnings (SEPH), by type of employee for selected industries classified using the North American Industry Classification System (NAICS), annual (current dollars), March 31, 2017 - data extracted August 31, 2017

Data accessed August 31, 2017