EB-2018-0085

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an application by Ontario Power Generation Inc. pursuant to section 78.1 of the *Ontario Energy Board Act, 1998* for an Order or Orders determining payment amounts for the output of certain of its generating facilities for the period from January 1, 2017 to December 31, 2021;

AND IN THE MATTER OF a motion by Ontario Power Generation Inc. pursuant to Rule 40 of the Ontario Energy Board's Rules of Practice and Procedure for an order or orders to vary the Decision and Order EB-20160152.

MOTION RECORD AND BOOK OF AUTHORITIES OF ONTARIO POWER GENERATION INC.
(on Motion to Review and Vary)

March 6, 2018

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26. Ontario Energy Board, *Regulated Price Plan – Price Report*, *May 1, 2017 to April 30, 2018*, April 20, 2017

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30. Ontario Energy Board, *Decision With Reasons re OPG Payment Amounts for Prescribed Facilities* in EB-2007-0905, November 3, 2008 (excerpt)

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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.

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[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

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[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.

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[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.

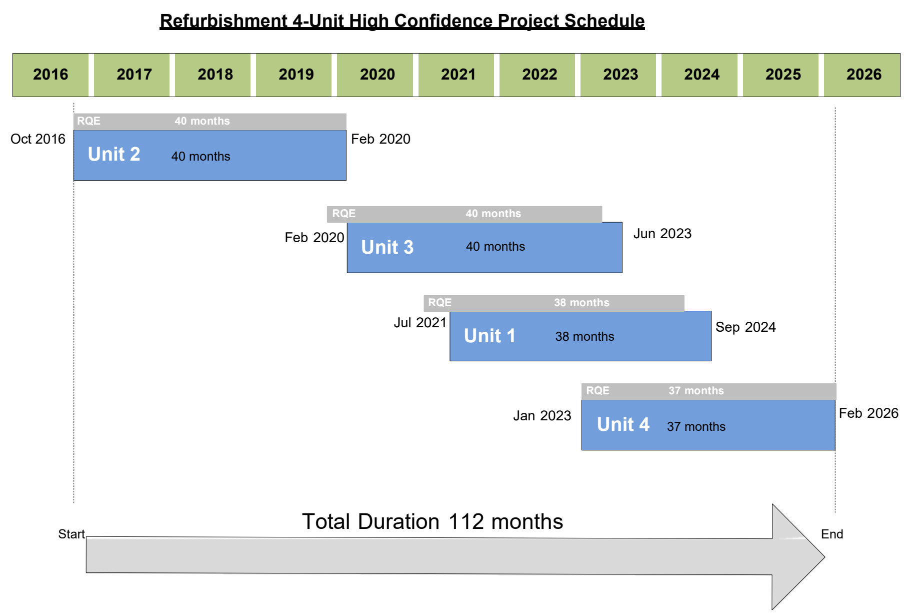
5.3 Darlington Refurbishment Program

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:

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[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]

[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:

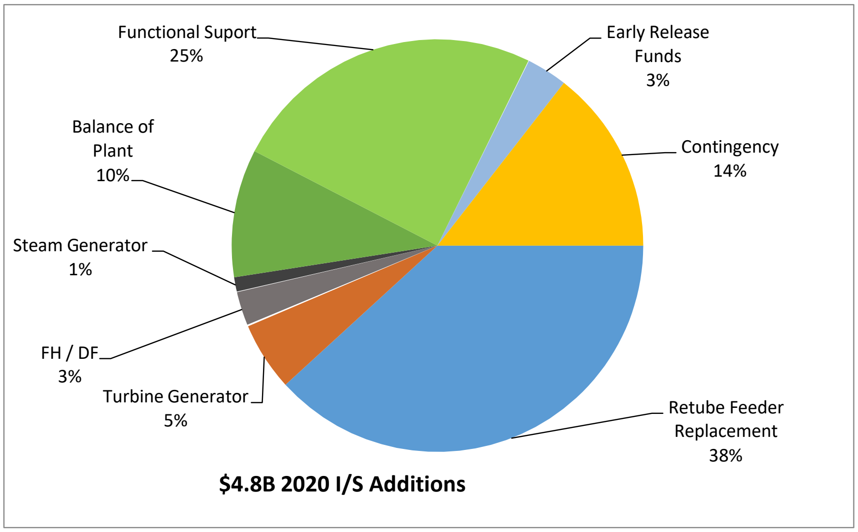
1. Original Request: Exh D2-2-1 page 6.
2. Update for removal of the Heavy Water Facility project (D2O project): Exh D2-2-10 Table 2 and Exh N2-1-1.
3. Net: Confirmed Tr Vol 1 pages 23 and 24 and Exh N2-1-1.

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."

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[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.

[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 off-ramps, 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.

[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	65.36	67.16	67.18	67.93	67.36	71.09	76.48	72.46	78.83	66.84
Pickering A													
WANO NPI (Index)	60.84	61.10	47.70										70.90
2-Year Unit Capability Factor (%)	56.60	68.00	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

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

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

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[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

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[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.

[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

[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

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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

[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

[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.

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[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.

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[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

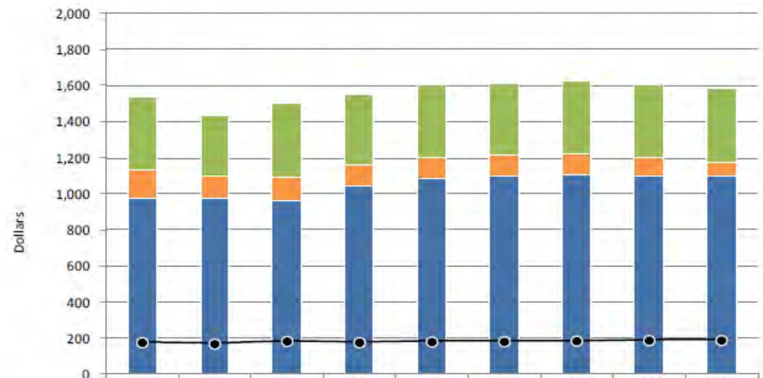
Background

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]

[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 75^{th} percentile rather than 50^{th} 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]

[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

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[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]

[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.

[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,

[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.

[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.

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

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.

[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.

[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

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[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

[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.

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[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

[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 <u>the OPG weighted average payment amount</u>" (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 constant, 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

Rate Smoothing and Mid-term Production Review

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.

Deferral and Variance Accounts

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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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 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

[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

Inputs and Assumptions												
Year	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

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

Rate Smoothing and Mid-term Production Review

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.

Deferral and Variance Accounts

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.

STAKEHOLDER CONSULTATION

1.0 PURPOSE

This evidence provides a description of the stakeholder consultation process that OPG held while it was developing this 2017-2021 payment amounts application.

Given the novel elements of this application (in particular, the transition to incentive regulation), OPG found it beneficial to share its plans for the application with stakeholders while the filing was still under development.

2.0 BACKGROUND

OPG first held stakeholder consultation sessions in late 2014 and early 2015 regarding the company's potential 2016-2020 payment amounts application (the "initial consultation"). The consultation process consisted of three information sessions. While OPG did not ultimately file an application for 2016 payment amounts, the stakeholder feedback from that process was helpful in developing this application. OPG has included the agendas from the initial consultation as attachments to this schedule.

Following the initial consultation, OPG held a series of consultation sessions regarding the current application for 2017-2021 payment amounts.

This schedule provides an outline of the entire consultation process, including the initial consultation and the subsequent sessions. It includes a summary of material changes that OPG made to this application based on feedback from stakeholders.

3.0 OBJECTIVE

The objective of the consultation process was to inform stakeholders about the application and to seek input on OPG's transition to incentive regulation.

4.0 PROCESS

4.1 Initial Consultation

In the initial consultation, OPG held three stakeholder information sessions regarding its potential 2016-2020 application. These sessions were held on December 17, 2014, January 22, 2015, and February 18, 2015. Copies of the presentations that were made at the session and facilitator notes are posted on OPG's website at: http://www.opg.com/about/regulatory-affairs/stakeholder-information/Pages/payment-amounts.aspx.

OPG invited stakeholders who participated in the last OEB proceeding regarding OPG's payment amounts, and other stakeholders who, in OPG's view, may have a material interest in the application. Funding was offered to participants who qualified under the funding guidelines.

The information sessions were held on a non-confidential, without-prejudice basis. Steve Klein, VP and Practice Manager at OPTIMUS | SBR was retained as a neutral, third-party facilitator and to document and report on the sessions.

The December 17, 2014 session highlighted the challenges and uncertainties inherent in OPG's operating environment for the five year period commencing in 2016. In addition, the session provided information on the Inflation Factor Analysis and Total Factor Productivity Study for OPG's hydroelectric operations prepared by London Economics International LLC. A copy of the session agenda is provided in Attachment 1.

At the January 22, 2015 session, OPG outlined proposed regulatory approaches for both hydroelectric and nuclear facilities. A copy of the session agenda is provided in Attachment 2.

At the February 18, 2015 session, OPG gave stakeholders another opportunity to request clarification or ask other questions about the materials presented at the second information session. OPG also presented updated plans on various aspects of the application, as they were developing. A copy of the session agenda is provided in Attachment 3.

4.2 2016 Consultation

Since OPG ultimately did not apply for new payment amounts in 2016, it held a further round of consultations on the current application in 2016. These sessions were held on February 8, 2016, March 21, 2016, and May 19, 2016. As it did in the initial consultation, OPG invited parties that participated in the previous application and retained OPTIMUS | SBR to facilitate and provide notes. Copies of the presentations that were made at the session and facilitator notes are posted on OPG's website at: http://www.opg.com/about/regulatory-affairs/stakeholder-information/Pages/payment-amounts.aspx.

At the February 8, 2016 session, OPG presented the company's plan to file an application covering payment amounts for 2017-2021. A copy of the session agenda is provided in Attachment 4. OPG presented the structure and major elements of the company's planned application. The session included a keynote presentation by OPG President and CEO Jeffrey Lyash, as well as detailed updates on the Darlington Refurbishment Program ("DRP") and on the Pickering Life Extension program.

The March 21, 2016 session was held at the Darlington Energy Complex. Participants toured the reactor mock-up used to prepare for the DRP. While touring the Darlington site, stakeholders were given an overview of the Facility and Infrastructure Projects and Safety Improvement Opportunities. OPG briefed the participants on the scope of the DRP, the company's DRP contracting strategy, and provided an overview of the DRP-related evidence planned for the company's payment amounts application. A copy of the session agenda is provided in Attachment 5.

Following the consultations, OPG made a number of changes to the planned application, including:

i. Eliminating the proposal to establish hydro base rates using a 2017 forecast test year cost of service review – instead, the filed application escalates existing hydro payment amounts by the proposed price-cap index;

ii. Eliminating the proposed symmetrical earnings sharing mechanism for nuclear and hydro;
iii. Eliminating the situational off-ramp proposed for nuclear;
iv. Eliminating the New Cost of Capital Variance Account proposed to record differences in hydro return on equity during the incentive regulation ("IR") term;
v. Modifying the hydro x-factor, increasing the annual productivity adjustment from -1 per cent (as identified by the independent Total Factor Productivity study) to 0 per cent, reflecting OEB policy in the electric distribution sector;
vi. Expanding the application of nuclear stretch factor applied to include corporate support costs; and
vii. Expanding the proposed performance reporting metrics to include all of the key hydroelectric performance areas filed in OPG's prior payment amounts application (EB-2013-0321, Ex. F1-1-1, Appendix B) and all measures used in annual nuclear benchmarking.

OPG also held a briefing for stakeholders on the final application on May 19, 2016. A copy of the session agenda is provided in Attachment 6. Materials from this presentation are available at http://www.opg.com.

ATTACHMENTS

Attachment 1:	December 17, 2014 Information Session Agenda
Attachment 2:	January 22, 2015 Information Session Agenda
Attachment 3:	February 18, 2015 Information Session Agenda
Attachment 4:	February 8, 2016 Information Session Agenda
Attachment 5:	March 21, 2016 Information Session Agenda
Attachment 6:	May 19, 2016 Information Session Agenda

AGENDA

Information Session
December 17, 2014

Mini Auditorium – 700 University Avenue, Toronto, ON

8:45 a.m. – 9:00 a.m.	- Registration
9:00 a.m. – 9:15 a.m.	- Welcome - Introductions - Safety Rules - Agenda
9:15 a.m. – 10:00 a.m.	- Hydroelectric Overview
10:00 a.m. – 10:30 a.m.	- Discussion
10:30 a.m. – 10:45 a.m.	- Break
10:45 a.m. – 12:00 a.m.	- Hydroelectric TFP Study and Inflation Factor Assessment
12:00 a.m. – 12:30 p.m.	- Discussion
12:30 p.m. – 1:15 p.m.	- Lunch
1:15 p.m. – 2:00 p.m.	- Nuclear Overview
2:00 p.m. – 2:30 p.m.	- Discussion
2:30 p.m. – 2:45 p.m.	- Break
2:45 p.m. – 3:30 p.m.	- Status of the Deferral and Variance Accounts Application

Agenda

January 22, 2015

8:30 a.m. – 9:00 a.m.	• Registration	
9:00 a.m. – 9:15 a.m.	• Welcome / Opening Remarks • Agenda • Participant Introductions • Safety Rules • Session Approach	Randy Pugh, Director, Regulatory Affairs Steve Klein, VP and Practice Manager, Optimus | SBR
9:15 a.m. – 10:30 a.m.	• OPG's Initial Incentive Rate-making Proposal for Hydroelectric Operations	Mario Mazza, VP, Strategic Operations, Hydro-Thermal Operations Randy Pugh, Director, Regulatory Affairs
10:30 a.m. – 10:45 a.m.	• Break	
10:45 a.m. – 11:15 a.m.	• Hydroelectric Inflation Factor Assessment / Questions and Discussion	Julia Frayer, Managing Director, London Economics International LLC
11:15 a.m. – 12:00 p.m.	• Hydroelectric TFP Study Report / Questions and Discussion	Julia Frayer, Managing Director, London Economics International LLC
12:00 p.m. – 12:45 p.m.	• Lunch	
12:45 p.m. – 2:00 p.m.	• OPG's Initial Multi-year Cost of Service Proposal for Nuclear Operations	Carla Carmichael, VP Nuclear Finance Randy Pugh, Director, Regulatory Affairs
2:00 p.m. – 2:15 p.m.	• Closing Remarks	Randy Pugh, Director, Regulatory Affairs

AGENDA

Information Session
February 18, 2015

Main Auditorium – 700 University Avenue, Toronto, ON

8:30 a.m. – 9:00 a.m.	- Registration
9:00 a.m. – 9:10 a.m.	- Welcome - Introductions - Safety Rules - Agenda
9:10 a.m. – 10:30 a.m.	- OPG's Initial Incentive Rate-making Proposal for Hydroelectric Operations - Initial Proposal for Service Quality Metric Reporting for Hydroelectric and Nuclear Operations
10:30 a.m. – 10:45 a.m.	- Break
10:45 a.m. – 11:50 a.m.	- OPG's Initial Multi-year Cost of Service Proposal for Nuclear Operations
11:50 a.m. – 12:00 p.m.	- Closing Remarks

OPG Regulated Facilities Payment Amounts
Stakeholder Meeting - February 8, 2016

Feb. 8	Topic	Presenter
8:30-9:00	Arrival and Continental Breakfast	
9:00-9:10	Welcome and Introductions	**Andrew Barrett** VP, Regulatory Affairs **Chris Ginther** SVP Legal, Ethics and Compliance
9:10-9:20	Keynote Speaker	**Jeffrey Lyash** President and CEO
9:20-9:25	Agenda and Facilitation	**Steve Klein** OPTIMUS | SBR
9:25-9:40	Application Overview	**Colin Anderson** Director, Ontario Regulatory Affairs
9:40-10:20	Regulatory Methodology Overview - Nuclear	**Colin Anderson** Director, Ontario Regulatory Affairs
10:20-10:45	Break	
10:45-11:15	Regulatory Methodology Overview - Hydroelectric	**Randy Pugh** Director, Ontario Regulatory Affairs
11:15-12:00	Additional Discussion	**Steve Klein** OPTIMUS | SBR
12:00-1:00	Lunch	
1:00-1:30	Key Topic #1 – Darlington Refurbishment	**Gary Rose** VP, Planning and Project Controls, Nuclear Projects
1:30-2:00	Key Topic #2 – Pickering Life Extension	**John Blazanin** VP, Strategy and Support
2:00-2:30	Stakeholder Issues / Discussion / Wrap Up	**Steve Klein** OPTIMUS | SBR
2:30	Adjourn	

OPG Regulated Facilities Payment Amounts
Stakeholder Meeting at the DEC - March 21, 2016

March 21	Topic	Presenter
8:15 - 8:30am	Bus Pick up at Queen's Park	
8:30 – 9:45	Travel to Darlington Energy Complex (DEC)	
9:45 - 10:00	Arrival and Continental Breakfast	
10:00 – 10:05	Welcome and Introductions	**Colin Anderson** Director, Regulatory Affairs
10:05 – 10:10	Agenda and Facilitation	**Steve Klein** OPTIMUS | SBR
10:10 – 10:20	Keynote Speaker	**Jeff Lyash** President & CEO
10:20 – 10:40	Darlington Refurbishment - Session #1 Overview of Scope	**Gary Rose** VP, Planning and Project Controls, Nuclear Projects
10:40 – 10:55	DEC Safety Briefing on Mock Up	
10:55 – 11:20	Mock Up Tour Overview of the Re-tube and Feeder Replacement Mock Ups	**Mike Allen** SVP, Nuclear Refurbishment
11:20 – 11:30	Board Bus	
11:30 – 12:15	Bus Tour of the Darlington Site Overview of Facility and Infrastructure and Safety Improvement Projects	**Dragan Popovic** Project Director
12:15 – 1:15	Lunch	
1:15 – 2:00	Darlington Refurbishment - Session #2 Overview of OPG's Contract Strategy	**Meg Timberg** VP, Project Assurance
2:00 – 2:30	Darlington Refurbishment - Session #3 Overview of OEB Filing	**Gary Rose** VP, Planning and Project Controls, Nuclear Projects
2:30 – 2:45	Questions and Discussion	**Steve Klein** OPTIMUS | SBR
2:45	Bus Departs for Toronto	
4:00 (approx)	Bus Arrives in Toronto (Queen's Park)	

Payment Amounts for OPG's Prescribed Facilities

Stakeholder Information Session – May 19, 2016

	Topic	Presenter
8:00 – 8:30	Arrival and Continental Breakfast	
8:30 - 8:40	Welcome and Introductions	**Chris Fralick** VP, Regulatory Affairs
8:40 - 8:50	Facilitator's Opening Remarks and Session Protocol	**Steve Klein** OPTIMUS | SBR
8:50 - 9:40	Application Overview and Regulatory Framework	**Barb Reuber** EB-2016-0152 Case Manager
9:40 - 10:10	Nuclear Operations OM&A, Capital Projects and Production Forecast	**Carla Carmichael** VP, Nuclear
10:10 - 10:25	Break	
10:25 - 10:55	Support Services and Compensation Costs	**Donna Rees** Director, Total Rewards
10:55 - 11:30	Rate Base, Depreciation, Nuclear Liabilities, Pension/OPEB, Deferral and Variance Accounts	**Alex Kogan** VP, Business Planning and Reporting
11:30 - 11:50	Cost of Capital	**Randy Pugh** Director, Ontario Regulatory Affairs
11:50 - 12:15	Closing Remarks	**Chris Fralick** VP, Regulatory Affairs
12:15 - 12:30	Questions / Wrap Up/Adjourn	**Steve Klein** OPTIMUS | SBR
12:30 - 2:00	Lunch	

Ontario Energy Board

Commission de l'énergie de l'Ontario

EB-2011-0286

Filing Guidelines for Ontario Power Generation Inc.

Setting Payment Amounts for Prescribed Generation Facilities

Issued: July 27, 2007 (EB-2006-0064)
Revised: November 27, 2009 (EB-2009-0331)
Revised: November 11, 2011

Table of Contents

1. PART 1: INTRODUCTION

This document provides the filing guidelines for Ontario Power Generation Inc. ("OPG") regarding the setting of payment amounts for OPG's prescribed generation facilities. The Board expects that OPG will comply with these filing guidelines. This document is not a statutory regulation, rule or code issued under the Board's authority and does not preempt the Board's discretion to make any order or give any direction as it determines necessary concerning any matters raised in relation to the setting of payment amounts for the prescribed generation facilities, including in relation to the production by OPG of additional information which the Board on its own motion or at the request of a party considers appropriate.

This document sets out specific filing guidelines for purposes of the setting of payment amounts for certain of Ontario Power Generation Inc.'s ("OPG") generation facilities under section 78.1 of the *Ontario Energy Board Act, 1998* (the "Act").[1] The generation facilities in question are identified in the *Payments Under Section 78.1 of the Act Regulation*, O. Reg. 53/05 ("O. Reg. 53/05") and are: Sir Adam Beck I, Sir Adam Beck II, Sir Adam Beck Pump Generation Station, De Cew Falls I, De Cew Falls II (all of the foregoing being hydroelectric generating stations located in the Regional Municipality of Niagara), the R.H. Saunders hydroelectric generating station on the St. Lawrence River, Pickering A nuclear generating station, Pickering B nuclear generating station and Darlington nuclear generating station (collectively the "prescribed generation facilities").

1.1 OVERVIEW OF LEGISLATIVE CONTEXT AND REGULATORY METHODOLOGY

Section 78.1 of the Act authorizes the Ontario Energy Board (the "Board") to set payments to be made to OPG with respect to the output of the prescribed generation facilities. Under O. Reg. 53/05, the Board's authority in that regard commenced on April 1, 2008.

In addition to identifying the prescribed generation facilities, O. Reg. 53/05 empowers the Board to establish the form, methodology, assumptions and calculations to be used in making an order that determines payment amounts for the purpose of section 78.1 of

[1] The working assumption reflected in this version of the guidelines is that OPG will be filing a payment amounts application in 2012 for test years 2013 and 2014. The prior test years for which the Board set OPG's payment amounts were 2011 and 2012. It is assumed that actuals will be available for 2009, 2010 and 2011 as well as the most recent forecast for the 2012 (current) bridge year. Accordingly, the term "historical" refers to 2009, 2010 and 2011 actuals and "Board-approved" refers to the numbers which support the payment amounts approved by the Board for 2011 and 2012.

the Act. It also contains rules that must be followed by the Board in setting those payment amounts.

These filing guidelines are informed by the previous two proceedings on OPG payment amounts (EB-2007-0905 and EB-2010-0008) and reflect directions contained in the decisions of these proceedings.

1.2 REQUIREMENTS OF O. REG. 53/05

O. Reg. 53/05 affects the setting of payment amounts for the prescribed generation facilities in three principal ways: first, by requiring that OPG establish certain deferral and variance accounts and that the Board ensure recovery of the balance in those accounts subject to certain conditions being met; second, by requiring that the Board ensure that certain costs, financial commitments or revenue requirement impacts be recovered by OPG; and third, by setting certain financial values that must be accepted by the Board when it makes its first order under section 78.1 of the Act. The last item has now been addressed.

1.3 BOARD DIRECTIVES AND UNDERTAKINGS FROM PREVIOUS DECISIONS*

Directives and Undertakings Include	EB-2010-0008 Decision with Reasons Page Number
Niagara Tunnel - The Board will expect OPG to file Project Execution Plans, as well as any other progress reports completed over the duration of the project, at the time of the prudence review.	28
Nuclear Benchmarking - The Board directs OPG to continue undertaking the benchmarking work and to produce a report to be filed with the next cost of service application. The methodology and report format will be consistent with that filed in EB-2010-0008.	45
Nuclear Staffing – The Board will direct OPG to conduct an examination of staffing levels as part of its next benchmarking study.	46
The Board expects to review the initiatives OPG has taken and intends to take to improve the Forced Loss Rate.	46
Pickering B Continued Operations – The Board expects OPG to address the specifics of the benefits analysis including the unit capability factors, the price used for comparative purposes and the absence of a contingency component in the cost estimate, more fully in its next application.	52

Directives and Undertakings Include	EB-2010-0008 Decision with Reasons Page Number
Nuclear Fuel Procurement – In the next proceeding, the Board will examine the program to determine whether OPG is optimizing its contracting. The Board will therefore direct OPG to file an external review as part of its next application.	55
Nuclear Rate Base – In the next proceeding, the Board will re-examine the issue of rate base additions and the accuracy of OPG's forecasts. The separate presentation of data related to ARC will assist in this regard.	59
Darlington Refurbishment – The Board expects OPG to file updated information on its progress for examination in the next proceeding.	71
Darlington Refurbishment – As DRP is a multi-year project, the Board expects that in future payments cases, the business case will be updated.	72
Compensation – The Board will therefore direct OPG to file on a FTE basis in its next application and to restate historical years on that basis.	84
Compensation – The Board expects to examine the issue of overtime more closely in the next proceeding. The Board expects OPG to demonstrate that it has optimized the mix of potential staffing resources.	84
Compensation – The Board directs OPG to conduct an independent compensation study to be filed with the next application.	88
Pension and OPEB – OPG is directed to provide a fuller range and discussion of alternatives to the use of AA bond yields to forecast discount rate in its next application.	91
The Board will direct OPG to file an independent depreciation study at the next proceeding.	97
The Board directs OPG to re-address the hydroelectric incentive mechanism ("HIM") structure in its next application.	148
IRM – Following a preliminary Board review, the Board expects OPG to provide a proposed work plan and status report for an independent productivity study as part of its 2013 and 2014 cost of service application.	156

Directives and Undertakings Include	EB-2011-0090 Decision and Order on Motion Page Number
Pension and OPEB Variance Account – The Board expects OPG to provide an independent actuary's report and an audit opinion.	14

* Only indicates Board direction for filing purposes

2. PART 2: FILING GUIDELINES

2.1 INTRODUCTION

OPG's application to the Board should provide sufficient detail to enable the Board to make a determination as to whether the proposed payment amounts are just and reasonable. The material presented is OPG's evidence and the onus is on OPG to prove the need for and the basis for the proposed new payment amounts. A clearly written application that advocates the need for the proposed payment amounts, complete with sufficient evidence and justification for the proposed payment amounts, is essential to facilitate an efficient regulatory process and a timely decision.

In the previous proceeding, the Board observed that at times the analysis was complicated by the fact that data was presented in ways which were not always comparable. The Board expects OPG to present data on a consistent basis so that comparisons are accurate.

The 2013-2014 payment amounts application will be OPG's third cost of service application. To the extent that materials are the same or substantially the same as those filed in previous applications, OPG shall indicate this to improve the efficiency of the review.

The Board remains cognizant of the large number of interrogatories that a rate (or in this case payment) setting process can generate. The requirement for a large number of interrogatories in the previous cases suggests that OPG and the interested parties do not have a common understanding of the information required to support the application. OPG should strategically consider the clarity and materiality of the evidence, with the goal of providing a clear and concise narrative of its filing. The evidence should be designed to increase the understanding of the parties with the overall objective of reducing the number and scope of interrogatories required. The Board also advises parties to carefully consider the relevance of their interrogatories when assessing an application and whether the issue being explored is material.

In determining what evidence to file, OPG should consider what information the Board and the intervenors are likely to request, and provide that information in the filed evidence rather than waiting for the request to be made at the hearing. This will ensure a better use of hearing time, and a more focused and informed cross examination.

In order to facilitate an efficient review of interrogatories and responses, the filing of interrogatories and responses must be sorted by issue.

The filing shall contain the following nine exhibits:

Exhibit A Administrative Documents
Exhibit B Rate Base
Exhibit C Cost of Capital and Capital Structure
Exhibit D Capital Projects
Exhibit E Production Forecast
Exhibit F Operating Costs
Exhibit G Operating Revenue
Exhibit H Deferral and Variance Accounts
Exhibit I Determination of Payment Amounts

Each exhibit shall provide the identified data for each category of prescribed generation facility (nuclear and hydroelectric). Each exhibit shall also explain how allocations have been made from total corporate to the prescribed generation facilities as a whole and the non-prescribed generation facilities as a whole, and then from the prescribed generation facilities as a whole to each of the nuclear and hydroelectric classes of prescribed generation facilities.

Excel spreadsheets shall be provided as appropriate to the data in question. Generally, formulae indicating on-sheet calculations shall be provided. As a minimum, OPG shall file an Excel spreadsheet summarizing production forecast (as noted in section 2.6), compensation and benefits (as noted in section 2.7.1) and a Revenue Requirement Work Form ("RRWF") in Excel format. The RRWF will generally replicate the data and tables that OPG files to support the payment amounts order. The RRWF will be filed with the application and will reflect the payment amounts for which OPG is seeking approval.

2.1.1 Key Planning Parameters

The key planning parameters listed below form the basis of how the detailed guidelines provided in this document should be interpreted or applied.

The filing should be made in accordance with:

- International Financial Reporting Standards ("IFRS"), on the understanding that OPG is required to adopt IFRS for 2012.

  For the historic years, actuals will be filed on the basis of Canadian Generally Accepted Accounting Principles ("CGAAP"). OPG should refer to the *Report of the Board: Transition to IFRS;* dated July 28, 2009 ("Board Report"), and subsequent amendments and addendum for guidance on IFRS. While this Board Report was directed to electricity and gas distributors, the Board will consider OPG's transition to IFRS in the context of the policies established in the Board Report.

OPG is required to identify in its application the financial differences and resulting revenue requirement impacts arising from the adoption of modified IFRS accounting. This is consistent with requirements set out in the Board Report.

As OPG is expected to adopt modified IFRS for financial reporting in 2012, OPG is required to present all historical years up to 2010 on a CGAAP basis, historical year 2011 on both CGAAP and modified IFRS basis, bridge year 2012 and test years 2013 and 2014 on a modified IFRS basis. Where there are differences in information between CGAAP and modified IFRS for the historical year 2011, the presentation of the information must clearly show the differences.

In addition, OPG shall meet the following guidelines in preparing its filing:

- Six years of data shall be submitted, as a minimum. The years are defined as:

  - Test Years = prospective payment years (typically 2 years)
  - Bridge Year = current year
  - Historic Years = last 3 complete years of actuals (as a minimum)

- Multi-year data showing data for all of the Historic Years, Bridge Year and Test Years shall be presented on the same sheet for the summary/main schedules

- Where applicable, for the each of the Historic Years, a detailed variance analysis shall also be provided **comparing Board-approved to actual costs and production**. The use of the phrase "Board approved" in these filing guidelines refers to the set of data used by the Board as the basis for approving the most recent payment amounts. It does not mean that the Board, in fact, "approved" any of the data, but only that the final approved payment amounts were based on that data.

- A detailed variance analysis for costs and production shall be provided for each historic and bridge year compared to the prior year. This analysis shall explain the reasons for the variance, the drivers of the variance and the contribution of each towards the total year-over-year variance.

- Written direct evidence shall be presented before the data schedules

- With respect to the claimed revenue sufficiency/deficiency, OPG shall provide a summary of the drivers of the sufficiency/deficiency for each of the Test Years, along with how much each driver contributes

- OPG shall file twelve paper copies and a copy in electronic form. The electronic form, including appendices and attachments, shall be in searchable/unrestricted

PDF format. OPG shall also file a single consolidated file of the application on CD or USB flash drive.

A filing that includes all documentation detailed in this document will be considered complete for purposes of further processing by the Board.

2.1.2 Confidential Information

Unless otherwise directed by the Board, any request for confidential treatment of information by OPG must be made at the time of the filing and in accordance with the Board's *Practice Direction on Confidential Filings.* The onus is on OPG or the entity requesting confidential treatment to demonstrate to the satisfaction of the Board that confidential treatment is warranted. It is the expectation of the Board that OPG or any other entity requesting confidential treatment will make every effort to limit the scope of their requests for confidentiality to an extent commensurate with the commercial sensitivity of the information at issue or with any legislative obligations of confidentiality or non-disclosure, and to prepare meaningful redacted documents or summaries so as to maximize the information that is available on the public record.

2.2 EXHIBIT A ADMINISTRATIVE DOCUMENTS

The administrative documents identified in this section provide the background and summary to the filing. There are three sections:

1) Administration;
2) Overview/summary of the filing; and
3) Background financial information.

The detailed guidelines for each section are shown below.

This exhibit should be treated as an administrative exhibit and should exclude all other information, such as production and revenue forecasts, cost of capital summary, rate base evidence and the operating, maintenance and administration (OM&A) budget. These topics should be addressed in the appropriate exhibits that follow.

This exhibit should, however, include a brief summary of OPG's filing regarding the specific directions set out in the previous proceedings (see section 1.3 above) and references to where the detailed evidence can be found.

2.2.1 Administration

- Table of Contents/Exhibit List
- Nature of filing
- List of specific approvals requested
- List of relevant statutory provisions (such as any provisions of, or regulations under, the *Ontario Energy Board Act, 1998* or the *Electricity Act, 1998*)

- Contact information
- Draft issues list – including preliminary prioritization of primary and secondary issues
- Procedural Orders/motions/correspondence
- Identification of areas where there has been deviation from IFRS
- Relevant maps (or provide link to webpage where maps can be found)
- Organization charts
- Planned changes in corporate or operational structure
- Relevant company policies and regulations
- List of witnesses and their curriculum vitae

2.2.2 Overview/Summary

- Summary of filing (purpose, need and timing of the filing)
- Budget directives and guidelines (capital and operating budgets), including economic assumptions used
- Changes in methodology (accounting including IFRS, etc.) that would affect any of the Historic, Bridge or Test Years
- Schedule of overall revenue sufficiency/deficiency
  - Numerical schedules detailing the causes of the sufficiency/deficiency
  - Complete and detailed references to the data contained in the detailed schedules and tables shall be provided so that parties can map the summary cost driver information to the evidence supporting it
  - A detailed narrative of the causes of the sufficiency/deficiency highlighting the significant issues.
- An overview of the allocation methodology for assets, costs and revenues to the prescribed and non-prescribed assets, and to the nuclear- and hydroelectric-specific businesses
- Summary and status of Board directives from the EB-2010-0008 and EB-2011-0090 Decisions. OPG should clearly indicate how these have been or are being addressed in the current application.
- Summary or copy of relevant orders from any federal or provincial agency, Ministerial Directives and Shareholder Directives.

2.2.3 Background Financial Information

- Audited OPG financial statements approved by OPG's Board of Directors for each of the Historic Years (or provide the webpage address of the location on SEDAR or EDGAR where these audited financial statements can be found)
- Audited OPG financial statements should be provided as soon as they are available. If the statements are not available at the time of filing, OPG should provide these as an update
- Most recent quarterly OPG financial reports
- Rating agency reports for each of the Historic Years and Bridge Year
- Audited prescribed generation facilities financial statements for the Historic Years
- An overview of how the provisions of O. Reg. 53/05 are reflected in the filing compared to data in the financial statements

- To address the concern of a potentially significant variance between the date of the audited financial statements and the date of filing, a detailed reconciliation of the financial results shown in the audited financial statements and the financial results contained in the filing shall be provided
- OPG Board of Directors approved 2012 – 2014 Business Plan for the regulated components of OPG, for the hydroelectric business, and for the nuclear business. Any previous business plans that include part of the test period should also be filed. If any claim for confidentiality is advanced with regard to any part of the Business Plan, a claim for confidentiality should be made in accordance with Board's *Practice Direction on Confidential Filings*.

2.3 EXHIBIT B RATE BASE

A description of the prescribed generation facilities, and of any financial assets, shall be provided. For nuclear rate base, a separate presentation of asset retirement costs ("ARC") associated with nuclear liability obligations is required.

Items used in the computations or derived shall include opening and closing balances of the net fixed assets, working capital, accumulated depreciation, changes in working capital, accrued deferred earnings, and annual amortization of accrued deferred earnings.

The information presented here shall cover three areas:

1) List of gross assets (property, plant and equipment), including capital budgets and intangible assets (e.g. Computer software) if any, included in rate base;
2) Accumulated depreciation and amortization;
3) Working capital including cash working capital calculation, Fuel Inventory (for the nuclear business), and Materials and Supplies.

For each of these areas there will be some common statements that shall be provided summarizing the rate base. The schedules for rate base should include all Historic Years, Bridge Year (actuals to date, balance of year as budgeted) and Test Years. Additional statements that should be provided for 1 and 2 include:

<u>Continuity statements</u>

The continuity statements must provide year-end balances and include directly attributable costs, for example, capitalized borrowing costs.

<u>Summary variance explanation</u>
A written explanation shall be provided to identify the drivers to the variance for rate base. This applies to OPG's rate base for the following comparisons:

- Board-approved vs. actual for each of the Historic Years
- Board-approved vs. Bridge Year

- Year over year analysis for the six year period

2.3.1 Gross Assets – Property, Plant and Equipment and Intangible Assets

Continuity statements should be provided as indicated above.

- Required statements and analysis should be broken down by function
- A detailed breakdown should be provided by major plant account for each functionalized plant item for each of the Historic Years, Bridge Year and Test Years. For the Test Years, each plant item should be accompanied by a written description
- Mid-year averages should be provided

2.3.2 Accumulated Depreciation and Amortization

Continuity statements and a summary variance explanation shall be provided as indicated above for each of the Historic, Bridge and Test Years by asset account. Continuity statements shall be reconcilable to calculated depreciation costs.

2.3.3 Working Capital Calculation

Working capital shall be provided for the each of the Historic, Bridge and Test Years. The results shall be provided on a single schedule for comparison. The basis for the calculation of cash working capital must be detailed.

2.4 EXHIBIT C COST OF CAPITAL AND RATE OF RETURN

OPG shall ensure that the total capitalization in the filing (debt and equity) equates to the total rate base.

2.4.1 Capital Structure – Amounts & Ratios

The following elements of the proposed capital structure shall be detailed, with the necessary schedules, for each of the Historic, Bridge and Test Years:

- Long-term debt
- Short-term/unfunded debt (to equate total capitalization with rate base)
- Preference shares
- Common equity

Justification for proposed capital structure is required, including an explanation of the following:

- Non-scheduled retirement of debt or preference shares and buy back of common shares
- Long-term debt, preference shares and common share offerings

- Since the establishment of the prescribed asset classes, the assumptions and methodology used:

    - to develop prescribed generation asset valuations
    - to allocate OPG's debt to the prescribed generation facilities as a whole
    - to allocate OPG's debt as between the prescribed nuclear and hydroelectric generation facilities

- A historic accounting of changes to OPG's capital structure including:
    - Non-scheduled retirement of debt or preference shares or buy-back of common shares
    - Issuances of long-term debt, preference shares and common shares
- Discussion of material changes in the capital structure (i.e. increased or decreased equity thickness) of OPG, and the reasons for these changes
- All internal or commissioned reports, studies or analysis, from 2009 to the date of filing, of how to value OPG's assets and how to allocate debt, by business unit or asset class.

2.4.2 Component Costs of Debt

The following shall be provided for each of the Historic, Bridge and Test Years:

- Calculation of the cost of each item
- Justification of forecast costs by item including key economic assumptions
- Profit or loss on redemption of debt
- Consensus Forecasts – latest interest rate forecast based on a selection of forecasters that are common to utilities (e.g., the major banks and the Bank of Canada).

2.4.3 Calculation of Return on Equity

Justification for the proposed return on equity is required, including the filing of supporting documentation, e.g. Global Insight reports.

2.4.4 Nuclear Waste Management and Decommissioning Costs

This section provides a summary of OPG's obligations for nuclear waste management and decommissioning. This exhibit shall also provide the funding responsibilities as described in the Ontario Nuclear Funds Agreement.

Any updates or revisions to the Ontario Nuclear Funds Agreement Reference Plan must be summarized and the financial impacts explained in appropriate detail, including a reconciliation with the Board-approved amounts for 2011 and 2012. If the reconciliation is summarized elsewhere in the application, the reference shall be provided in this section.

The information shall be disaggregated to present Darlington and Pickering separate from Bruce.

The information presented shall cover:

- the revenue requirement treatment of OPG's liabilities for decommissioning its nuclear stations and nuclear used fuel and low and intermediate level waste management
- the revenue requirement treatment of OPG's liabilities for decommissioning Bruce

Further, the exhibit shall include:

- A summary of net book values of OPG's nuclear stations including Bruce, noting amounts of unamortized asset retirement cost, for Historic, Bridge and Test years.
- A summary of the forecast pre-tax charge in OPG's income statement due to the nuclear liabilities and the segregated funds

2.5 EXHIBIT D CAPITAL PROJECTS

<u>Capital Budget - Historic Years, Bridge Year and Test Years</u>

- Policies

  - OPG's capitalization policy and any changes to that policy should be presented as part of the capital budget evidence

  - Proposed accounting treatment, including the treatment of costs of funds for capital projects that have a project life cycle greater than one year, should be provided

- Capital Expenditures – Provide a summary of capital expenditures for the Historic, Bridge and Test years, including the Board-approved amounts for the Historic and Bridge years.

- Capital budget by project

For Capital Projects of:	Detail Required
$20 million or more	Name, description, need, start date, in-service date, and cost for each project Business Case for each project of $20 million or more Provide actual in service dates (month and year) for major capital projects that closed to rate base in historical years and provide projected in service dates (month and year) for the bridge and test years Total cost of all projects in this category
Between $5 million and $20 million	Name, description and cost for each project Provide actual in service dates (month and year) for capital projects between $5 million and $20 million that closed to rate base in historical years and provide projected in service dates (month and year) for the bridge and test years Total cost of all projects in this category
Less than $5 million	Number of projects in this category, total cost of all projects in this category and average cost of the projects in this category Provide the total cost related to projects that will close to rate base in the test years

OPG shall provide an overall summary table of the business cases filed. The summary table should include the title of the business case, date prepared, the project stage, and status of the business case (i.e. full, partial, developmental), for the current case. Where applicable, the table should also indicate the business case's status in the previous proceeding, EB-2010-0008. Note that all of the above is also applicable to OM&A business cases.

- Variance analysis for capital projects of $20 million or more

  - A written explanation of variances should be presented where the variance is 10% or more of the project budget. Variance explanations should be provided for the following comparisons:

- Board-approved vs. actual for each of the Historic Years
- Board-approved vs. Bridge Year forecast

OPG shall provide a summary table for projects $5M and greater that were projected to go into service in 2011 and 2012 in the EB-2010-0008 application. The table should include the project stage as provided in the EB-2010-0008 application and the current status of the project.

2.6 EXHIBIT E PRODUCTION FORECAST

The production forecast and any normalization methodology shall be provided. A description of outage planning processes and production reliability initiatives shall also be provided.

- Explanation of causes and assumptions for the production forecast
- Production for all Historic, Bridge and Test Years
- Weather forecasting and hydrological forecasting methodologies
- All data used to determine the forecast should be presented in **MS Excel spreadsheet format**
- Comparison of historical data with the forecast data in regard to forecasting assumptions
- A variance analysis of energy output shall be provided for the following:

    - Board-approved vs. actual for each of the Historic Years
    - Board-approved vs. Bridge Year forecast
    - Year over year analysis for the six year period

- All economic assumptions and their sources used in the preparation of the production forecast shall be included in this section

- Where available, actual and forecast generation losses due to spill shall be filed.

HYDROELECTRIC INCENTIVE MECHANISM ("HIM")

An analysis of the HIM shall be provided. The analysis shall include an assessment of the benefits of HIM for ratepayers, the interaction between the mechanism and surplus baseload generation, and an assessment of potential alternative approaches.

2.7 EXHIBIT F OPERATING COSTS

This exhibit should include information that summarizes the total operating, maintenance and administration costs, including asset service fees and taxes.

This exhibit shall include benchmarking studies that update studies filed in previous applications or new benchmarking studies. Further, this exhibit shall include a consolidation of the benchmarking information so that comparisons are evident, e.g. TGC, nuclear capacity factors, and other safety, reliability and value for money measures.

The benchmarking shall note whether the basis is a forecast or actual results.

2.7.1 Operating, Maintenance & Administration and Other Costs

The required statements for each of the components of this section include trend data for operating costs by major item.

a) Operating, Maintenance & Administration Costs

Details of the budgets for each of the Historic, Bridge and Test Years shall be provided.

The OM&A statements for each year shall provide:

- A breakdown on a work basis of each major item that meets the threshold of the lesser of 1% of total expenses before taxes or $20 million

- Detailed information is to be provided for each expense incurred through the purchase of services or products that meets the threshold of the lesser of 1% of total expenses before taxes or $20 million. The information is to include, for each such expense:

  - a summary of the tendering process used
  - if a tendering process was not used, an explanation of why that was the case as well as a description of the pricing methodology used
  - the identity of the company transacting with OPG
  - a summary of the nature of the activity transacted

  In addition, the annual dollar value, in aggregate, for all such expenses shall be provided.

- A breakdown of the following by employee group: number of full time equivalents (“FTEs”) including contributions from part time employees; total salaries, wages and benefits; and salaries, wages and benefits charged to O&M. In addition, the following shall also be provided:

- Total compensation by employee group and average level per group
- Details of any pay-for-performance or other employee incentive program
- The status of pension funding and all assumptions used in the analysis

Information shall be presented in terms of FTEs. In some cases, OPG may choose to provide the information in terms of head count as well as FTEs. The basis for each breakout of compensation data will be specified:

- Head count or FTE
- Yearly average, mid year or year end

These data shall be provided in Excel spreadsheet table format.

- Employee benefit programs, including pensions, and costs charged to O&M shall include the following details:

  - historic actuarial reports
  - actuarial evidence to support pension and OPEB expense for the bridge year and test years including any educational notes or articles issued by the Canadian Institute of Actuaries on methods for determining discount rates used for reporting under CICA standards
  - CICA guidance, practice notes, etc. that provide information on approaches to selecting discount rates shall be filed
  - discussion and analysis on discount rates used for calculating pensions and OPEB benefit obligations, cost for the year and liabilities
  - a table that summarizes actual accounting expense compared to Board-approved expense and with amounts actually paid for pensions and OPEBs for the period April 1, 2008 to the end of the historical period
  - the most recent report filed with Financial Services Commission of Ontario
  - discussion on the impacts of the adoption of IFRS

- A variance analysis for OM&A, and components of OM&A (including Regulatory Affairs costs), shall be provided for the following:

  - Board-approved vs. actual for each of the Historic Years
  - Board-approved vs. Bridge Year forecast
  - Year over year analysis for the six year period

  A written explanation is required for any variance greater than or equal to 10% of category expenses.

b) Depreciation/Amortization/Depletion

- An independent depreciation study and summary of changes for depreciation, amortization and depletion by asset group shall be provided

- Details of provision for depreciation, amortization and depletion by asset group for each of the Test Years should be provided, as should comparative data for each of the Historic Years and Bridge Year, including asset amount and rate of depreciation

- An analysis of the impact on depreciation of the change from CGAAP to MIFRS

c) Corporate Cost Allocation

A summary of the corporate cost allocation shall be provided, including information showing the costs incurred at the corporate level, the methodology and assumptions used to allocate these costs to the prescribed and non-prescribed generation facilities and the methodology to allocate these costs to each of the prescribed nuclear and hydroelectric businesses. Details in relation to shared corporate services should include:

- type of service (IT, office space, etc.)
- total annual expense by service
- rationale and derivation of cost allocators used for shared costs, for each type of service (square footage/computers/headcount/etc.)
- any variances in 2011 and 2012 corporate cost allocation.

2.7.2 Taxes

OPG shall file information on its Historic, Bridge and Test years income tax and the detailed calculation supporting the data. The documentation shall include copies of the most recent tax returns and notice of assessment, re-assessment and statements of adjustments.

- A detailed tax calculation shall be provided for each of the Historic, Bridge and Test Years, including derivation of interest deducted, capital cost allowance showing differences from depreciation/amortization expense, all other differences from financial statement income, tax rates and payments in lieu of taxes included in deriving the revenue requirement.
- Details on the gross revenue tax applicable to the hydroelectric business shall be provided either separately or as part of the operating expenses for the hydroelectric business
- All reconciling items shall have supporting schedules and calculations.

2.8 EXHIBIT G OPERATING REVENUE

The revenue forecast, any normalization methodology and sales activities shall be provided here. The information presented shall include other revenue derived from the use of the prescribed generation facilities, broken down by revenue source.

2.8.1 Energy Revenue

This section shall include:

- Production and energy revenues for all Historic, Bridge and Test Years
- Schedule of production showing volumes, total revenues and unit revenues for each of the Historic, Bridge and Test Years

2.8.2 Other Revenues

Details of other revenue, broken down by revenue source, shall be provided. This shall include OPG's revenues and costs associated with the Bruce nuclear generating stations

- A variance analysis of other revenues shall be provided for the following:
    - Board-approved vs. actual for each of the Historic Years
    - Board-approved vs. Bridge Year forecast
    - Year over year analysis for the six year period
- A detailed explanation of how other revenues are attributed to the prescribed generation facilities shall be provided.

2.9 EXHIBIT H DEFERRAL AND VARIANCE ACCOUNTS

As described in Part 1, O. Reg. 53/05 contains a number of provisions regarding the establishment of deferral and variance accounts and the recovery of balances in those accounts. In this section, OPG shall include information necessary to enable the Board to deal with these accounts in the manner contemplated by O. Reg. 53/05, including OPG's proposals regarding the following:

- The end date for entries into the deferral and variance accounts
- Addressing timing differences between the end date for entries into the deferral and variance accounts and the effective date of the Board's order
- The number of years over which balances in the deferral and variance accounts should be recovered (subject to the maximum set out for each in O. Reg. 53/05)
- The interest rate for the nuclear liability deferral account referred to in section 5.2(1) of O. Reg. 53/05

OPG shall also identify any deferral or variance accounts that it may wish to have authorization to establish on and after the date of the Board's order.

In general, this exhibit should include:

- A listing and detailed description (including account definition) of all outstanding deferral and variance accounts - those specified by O. Reg. 53/05 as well as those established by the Board in previous decisions, including:

  - Hydroelectric Water Conditions Variance Account
  - Ancillary services Net Revenue Variance Account – Hydroelectric
  - Ancillary services Net Revenue Variance Account – Nuclear
  - Transmission Outages and Restrictions Variance Account
  - Pickering A Return to Service Deferral Account
  - Nuclear Liability Deferral Account
  - Nuclear Development Variance Account
  - Capacity Refurbishment Variance Account
  - Nuclear Fuel Cost Variance Account
  - Income and Other Taxes Variance Account
  - Bruce Lease Net Revenue Variance Account
  - Hydroelectric Interim Period Shortfall (Rider D) Variance Account
  - Nuclear Interim Period Shortfall (Rider B) Variance Account
  - Tax Loss Variance Account
  - Hydroelectric Deferral and Variance Over/Under Recovery Variance Account
  - Nuclear Deferral and Variance Over/Under Recovery Variance Account
  - Hydroelectric Surplus Baseload Generation Variance Account
  - Hydroelectric Incentive Mechanism Variance Account
  - Pension and OPEB Cost Variance Account

- Continuity statements listing opening balances, transaction details including recoveries where applicable, interest rates and carrying charges, and closing balances. The schedules shall reflect annualized data for the Historic and Bridge years. Notes shall be provided for any unusual transactions.
- A detailed proposal for recovery of the balance in the deferral and variance accounts, where applicable.

2.10 EXHIBIT I DETERMINATION OF PAYMENT AMOUNTS

This exhibit shall include the following:

- Calculation of Revenue Deficiency or Sufficiency
  - Determination of net income
  - Statement of rate base
  - Indicated rate of return
  - Gross and net deficiency or sufficiency in revenue.

- Proposed Payments Schedule and Analysis
  - Proposed payments and revenue adjustments
  - Detailed calculations of revenue under the current payments schedule and the proposed payment schedule
  - Detailed reconciliation of payment revenue and other revenue to the total

revenue requirement.
- Analysis of % change vs. current payment amounts
- Bill impact analysis

- Payment Design

  OPG shall, in addition to providing the existing design of payment amounts, include:

  - Analysis of the existing design of payment amounts and whether the design maximized efficient use of the generation facilities
  - Proposed payment design and rationale
  - Explanation of non-cost factors and their application to payment design.

- Payment Implementation

  OPG shall provide a description of the settlement process with the IESO, including a description of the timelines associated with the requested effective date.

Performance standards for processing applications

For applications filed on or after April 1, 2009

The Board's processes ensure that parties are given the opportunity to fully and fairly present their case. At the same time, subject to the overriding concern for fairness, the Board is committed to processing applications in an efficient and timely manner. A listing of timelines for processing various applications has been provided below. This listing describes typical application types filed with the Board and whether they result in oral or written hearings.

The Board is committed to follow these timelines but it should be noted that they are based upon the full scope of procedural events associated with each application type taking place in a predictable manner. This includes the evidentiary requirements of the applicant and the intervenors. The timely filings of the applicant and intervenors are important requirements if the Board is to achieve greater efficiency in processing applications.

Total period elapsed to board decision (calendar days) for application types

Municipal franchise or certificate	
Oral hearing	205

Municipal franchise or certificate	
Written hearing	90

Leave to construct or gas storage designation	
Oral hearing	210
Written hearing	130

Well drilling	
Oral hearing	210
Written hearing	130

Licence	
Individual application - oral hearing	210
Individual application - written hearing	130
Individual application - written hearing - one step notice	90 (60 days for feed-in tariff applications)

Licence

Total period elapsed to board decision (calendar days) for mergers, acquisitions, amalgamations and divestitures

A review of a SECTION 80 or 81 notice of proposal under SECTION 82 (generation, transmission, distribution ownership prohibition)	
Oral hearing	220
Written hearing	170

Sections 86 (change of ownership or control of systems)	
Oral hearing	180
Written hearing	130

Distribution rates	
Oral hearing	235

Distribution rates	
Standard written hearing	185
Streamlined written hearing	140

Quarterly rate adjustment filings - gas	
Written review	21

General application	
Motion to review - oral hearing	170
Motion to review - written hearing	120

Related information

April 1, 2009 - **Read the letter to Stakeholders**

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2016-0152

Ontario Power Generation Inc.

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

PROCEDURAL ORDER NO. 1
August 12, 2016

Ontario Power Generation Inc. (OPG) filed an application with the Ontario Energy Board (OEB) on May 27, 2016 under section 78.1 of the *Ontario Energy Board Act*, *1998*, S.O. 1998, c. 15, (Schedule B), seeking approval for changes in payment amounts for the output of its nuclear generating facilities and most of its hydroelectric generating facilities. The request seeks approval for nuclear payment amounts to be effective January 1, 2017 and for each following year through to December 31, 2021. The request 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 amount for the period January 1, 2017 to December 31, 2021. OPG filed supplemental evidence on July 29, 2016.

A Notice of Hearing was issued on June 29, 2016. Each of the following parties applied for intervenor status:

- Association of Major Power Consumers in Ontario (AMPCO)
- Canadian Manufacturers & Exporters (CME)
- Canadian Wind Energy Association and Canadian Solar Industries Association (jointly) (CanWEA/CanSIA)
- Consumers Council of Canada (CCC)
- Energy Probe Research Foundation (Energy Probe)
- Environmental Defence Canada Inc. (Environmental Defence)

- Green Energy Coalition (GEC)
- Independent Electricity System Operator (IESO)
- Lake Ontario Waterkeeper (LOW)
- London Property Management Association (LPMA)
- Ontario Association of Physical Plant Administrators (OAPPA)
- Power Workers' Union (PWU)
- Quinte Manufacturers Association (QMA)
- School Energy Coalition (SEC)
- Shell Energy North America (Canada) Inc. (Shell)
- SNC-Lavalin Nuclear Inc. and Aecon Construction Group Inc. (SNC/AECON JV)
- Society of Energy Professionals (Society)
- Sustainability-Journal
- Vulnerable Energy Consumers Coalition (VECC)

The SNC/AECON JV seeks status as an intervenor that is limited to participation in procedural steps that relate to or affect the confidentiality of the SNC/AECON JV confidential information.

AMPCO, CME, CanWEA/CanSIA, CCC, Energy Probe, Environmental Defence, GEC, LOW, LPMA, OAPPA, QMA, SEC, Sustainability-Journal and VECC also applied for cost eligibility.

No objection was received from OPG.

AMPCO, CME, CanWEA/CanSIA, CCC, Energy Probe, Environmental Defence, GEC, IESO, LOW, LPMA, OAPPA, PWU, QMA, SEC, Shell, SNC/AECON JV, Society, Sustainability-Journal and VECC are approved as intervenors. The list of parties in this proceeding is attached as Schedule A to this Procedural Order. Subject to the requirements outlined below with respect to cost eligibility for the participation in the proceeding by any experts retained by intervenors, the OEB has also determined that AMPCO, CME, CCC, Energy Probe, Environmental Defence, GEC, LOW, LPMA, OAPPA, QMA, SEC, Sustainability-Journal and VECC are eligible to apply for an award of costs under the OEB's *Practice Direction on Cost Awards*.

In correspondence filed on August 4, 2016, CanWEA/CanSIA advised the OEB that its cost eligibility request relates to a need to engage a consultant to prepare financial models regarding the cost effectiveness of the proposed extended operation of Pickering in comparison to existing and planned renewables.

For the reasons provided below, the OEB will not grant cost eligibility to CanWEA/CanSIA.

CanWEA and CanSIA are both associations. In assessing the cost eligibility of an association, the OEB has previously stated that it will consider the association's membership rather than considering the association separate and apart from its members.[1]

CanWEA is a national, non-profit association that promotes wind energy in Canada, and represents more than 450 corporate members including wind energy developers, owners and operators, wind turbine manufacturers and component suppliers, as well as a broad range of service providers to the industry.

CanSIA is a national trade association that represents solar energy companies involved with the delivery of solar energy products and services in Canada, or with the delivery of other products and services to Canada's solar energy sector, including manufacturers, installers, project developers, builders, architects, engineers, consultants, and a variety of other companies and organizations who contribute directly to solar projects in Canada.

The memberships of each of CanWEA and CanSIA consist principally of commercial service providers, generators and others (for example, utilities and government agencies).

Generators and utilities are *prima facie* not eligible for an award of costs under section 3.05 of the *Practice Direction on Cost Awards*. It has been the OEB's practice that commercial entities such as commercial service providers are also ineligible for an award of costs by reason that they primarily represent their own commercial interests rather than primarily representing an interest or policy perspective relevant to the OEB's mandate.

The OEB finds that, by virtue of their respective memberships, CanWEA and CanSIA are *prima facie* not eligible for an award of costs.

Under section 3.07 of the *Practice Direction on Cost Awards*, a party that is *prima facie* ineligible under section 3.05 may be found to be eligible for costs where "special circumstances" exist. The OEB is not of the view that there are special circumstances

[1] March 22, 2011 Decision on Issues and Cost Eligibility (EB-2011-0011).

that would justify granting CanWEA/CanSIA cost eligibility pursuant to section 3.07 in the context of this proceeding.

Cost eligible intervenors should be aware that the OEB will not generally allow the recovery of costs for the attendance of more than one representative of any party, unless a compelling reason is provided when cost claims are filed.

If any cost eligible intervenor plans to file expert evidence in this proceeding, the intervenor shall file a letter with the OEB describing the nature of the evidence, whether the expert evidence will be commissioned jointly with other intervernors, and the estimated cost. The estimated cost should include an explanation of any assumptions regarding the purpose and scope of the participation of the expert in the proceeding, and should include an estimate of any incremental time that will be spent by the intervenor's counsel or any other consultant(s) in relation to the expert evidence. The OEB is also making provision for OEB staff to file a letter relating to any expert evidence OEB staff plans to file. After reviewing this material, the OEB will consider whether and to what extent any costs associated with the participation of any expert(s) or the preparation of any expert report(s) will be eligible for cost recovery in accordance with the OEB's Practice Direction on Cost Awards.

Being eligible to apply for recovery of costs is not a guarantee of recovery of any costs claimed. Cost awards are made by way of an OEB order, typically at the end of a hearing. As this proceeding is expected to be lengthy, the OEB may consider a cost award process for interim disposition prior to the end of this proceeding.

Issues List

OPG filed a prioritized draft issues list with its application at Exh A1-10-1. A non-prioritized version of the draft issues list is attached as Schedule B to this Procedural Order.

The OEB is making provision for written submissions on the non-prioritized draft issues list. The parties will have the opportunity to make written submissions on the draft issues list and propose changes for the OEB's consideration. In proposing additional issues parties should provide justification and give consideration to whether the item is already included under one of the proposed issues. Similarly, parties proposing to remove, change or limit the scope of an issue on the draft issues list should provide justification.

After reviewing the submissions, the OEB will issue a final issues list. Only matters that are on the final issues list will be considered in this proceeding.

As noted in correspondence issued on November 11, 2011, with the *Filing Guidelines for Ontario Power Generation Inc. in Setting Payment Amounts for Prescribed Generation Facilities* (Filing Guidelines), the OEB will make provision for interrogatories on all issues. Following the filing of interrogatory responses, the OEB will make provision for submissions on categorizing issues into primary and secondary issues. Generally, any unsettled primary issues will proceed by way of oral hearing. Any unsettled secondary issues will proceed by way of written hearing. The OEB will make a determination on the categorization of issues after considering the submissions filed following the filing of interrogatory responses, and may direct that certain issues be excluded from settlement consideration and proceed by way of oral hearing.

Confidential Filings

OPG is seeking confidential treatment for certain portions of documents it has filed as part of its pre-filed evidence. The documents are the following:

1. The 2016-2018 Business Plan located at Exh A2-2-1, Attachment 1 (Business Plan)
2. The 2016-2018 Business Planning Instructions located at Exh A2-2-1, Attachment 2 (Business Plan Instructions)
3. The revenue comparison tables located at Exh G2-1-1, Table 1 and Exh G2-1-2, Table 1 (Revenue Tables)
4. The engagement letter with Concentric Energy Advisors located at Exh C1-1-1, Attachment 2 for the Cost of Capital Report (the Concentric Cost of Capital Engagement Letter)
5. The nuclear business case summaries found at Exh D2-1-3, Attachment 1 and Exh F2-3 3, Attachment 1 (collectively, the BCSs)
6. The Darlington Refurbishment Program attachments (collectively, the DRP Attachments):
    a. contract summaries at Exh D2-2-3, Attachments 1, 4 and 5 (DRP Contract Summaries)
    b. major DRP contracts at Exh D2-2-3, Attachments 6 to 10 (DRP Contracts)
    c. DRP Reports at Exh D2-2-8, Attachments 2, 3, 4 and at Exh D2-2-9, Attachment 2
    d. The business case summary for Heavy Water Storage and Drum Handling Facility at Exh D2-2-10, Attachment 1, Tab 1

7. OPG's 2014 income tax returns located at Exh F4-2-1, Attachment 1 (the 2014 Income Tax Returns)

OPG requested confidential treatment for two additional documents (considered part of DRP Attachments) that were filed as part of its July 29, 2016 update. These include:

8. The engagement letter with Concentric Energy Advisors, Inc. located at Exh D2-2-11, Attachment 2 for the Updated Assessment of Commercial Strategies Developed for the Darlington Refurbishment Program Retube & Feeder Replacement Work Package (Concentric DRP Engagement Letter)
9. The engagement letter with Pegasus Global Holdings, Inc. located at Exh D2-2-11, Attachment 4 for an assessment of OPG's plan and approach to the execution of the Darlington Refurbishment Program (Pegasus-Global Engagement Letter)

In accordance with the OEB's *Practice Direction on Confidential Filings* (the "Practice Direction"), OPG has provided its reasons for the confidentiality request, including reasons why it considers the information at issue to be confidential and the reasons why public disclosure of that information would be detrimental. OPG has filed redacted versions of the documents as part of its public filing (with the exception of the Steam Generator Contract, discussed below) and un-redacted versions as part of its confidential filing.

OEB Review Only Document

OPG has also requested review by the OEB only of certain business plan information related to OPG's unregulated business. OPG seeks permanent redaction for this information. The OEB will not be accepting submissions on the redactions that are proposed for OEB Review Only and will address this matter at a later date.

2014 Income Tax Returns

The OEB has reviewed the redactions that are proposed in the 2014 Income Tax Returns and has determined that it will grant OPG's request for confidential treatment of this information. The OEB is accepting the request for confidentiality on the grounds the information being redacted in the 2014 Tax Returns largely pertains to OPG's unregulated businesses and that the request qualifies for confidential treatment under Appendix B of the Practice Direction. Later in this order, the OEB has made provision for submissions on other OPG confidentiality requests. However, given that the OEB has granted OPG's request for confidentiality for the tax returns, it will not accept submissions on this matter.

Engineering, Procurement and Construction Services Contract for the Steam Generator Project

OPG has entered into an agreement with Babcock & Wilcox Canada Ltd. (BWXT) and Candu Energy Inc. (Candu) for the provision of Engineering, Procurement and Construction services for the Darlington Refurbishment Steam Generator project (SG EPC Contract).

OPG states that it had originally planned to file a summary of the contract and the redacted contract as part of its public filing, but following notification from Candu that "it was asserting confidential protection over all or parts of the contract", and so as to not prejudice Candu's position, OPG removed both documents from its public filing. An un-redacted version of the contract and a contract summary have been provided as part of the confidential filing.

The OEB understands that OPG is not asking for the entire SG EPC Contract to be treated as confidential. The portions that OPG is requesting be treated as confidential are identified in the un-redacted SG EPC Contract that has been filed as part of its confidential filings. In regards to Candu's position, the OEB does not know whether Candu intends to request confidential treatment for the entire contract or for portions of it, nor does it have an explanation for any such request. Accordingly, the OEB will grant intervenor status to Candu for the limited purpose of addressing the confidentiality of the SG EPC Contract. The OEB requires that Candu immediately notify the OEB whether it intends to participate in this proceeding.

If Candu participates in this proceeding, the OEB requires the following information from Candu. If it is Candu's intention to seek confidential treatment for the entire SG EPC Contract, then pursuant to section 5.1.4(c)(ii) of the Practice Direction, the OEB requires that Candu file a summary of the contract on the public record. On the other hand, if it is Candu's intention to request confidential treatment only for portions of the SG EPC Contract, then pursuant to section 5.1.4(c)(i) of the Practice Direction, Candu and OPG must jointly file a redacted version of the SG EPC Contract, that reflects the redactions that each is proposing, on the public record. An un-redacted version of the SG EPC Contract, identifying OPG's redactions was filed by OPG as part its confidential filings. The OEB will require that Candu also file an un-redacted version of the SG EPC Contract identifying the redactions it is proposing.

Pursuant to section 5.1.4(a) of the Practice Direction, OPG and, if applicable, Candu are also required to provide their respective reasons for the confidentiality request (as it pertains to the portions for which each is requesting confidential treatment), including the reasons why the information should be treated as confidential and the reasons why public disclosure of that information would be detrimental.

By not filing a redacted contract on the public record, OPG's request for confidentiality is not consistent with the requirements in the Practice Direction. Therefore, if Candu does not participate in this proceeding or if the OEB does not receive the stated notification from Candu within 5 days from the date of this Order, the OEB requires that OPG re-file the redacted SG EPC Contract on the public record.

The OEB notes that BWXT, also a party to the SG EPC Contract, has not applied for intervenor status and is not noted in OPG's letter on the matter as having expressed any concerns with OPG's request. The OEB notes that BWXT may have submissions on the matter and will therefore grant to BWXT intervenor status for the purpose of participating in the proceeding in respect of this specific request. If BWXT participates in this proceeding, it must make its request for confidentiality in accordance with the Practice Direction and follow the schedule for filings set out for Candu in this Order. Alternately, if BWXT does not wish to participate in this proceeding, it must notify the OEB of its intention within 5 days from the date of this Order.

The OEB does not have contact information for Candu or BWXT. Therefore, the OEB will require that OPG immediately provide a copy of this Order to Candu and BWXT.

Contracts with SNC Lavalin Nuclear Inc. and Aecon Construction Group Inc.
OPG is seeking confidential treatment for certain portions of the three contracts it has entered into with SNC Lavalin Nuclear Inc. and Aecon Construction Group Inc. Joint Venture (SNC/AECON JV). The three contracts are: (i) the Engineering Procurement and Construction Contract for Retube and Feeder Replacement project, (ii) the Engineering Procurement and Construction contract for Turbine Generators and (iii) the Extended Services Master Services Agreement. OPG has filed redacted and un-redacted versions of the contracts and contract summaries.

OPG states that it has requested certain redactions in these contracts on the basis of a specific request from SNC/AECON JV. Pursuant to section 5.1.4(a), the OEB requires that SNC/AECON JV file with the OEB its reasons for the confidentiality request, including the reasons why the information at issue is considered confidential and the reasons that public disclosure of that information would be detrimental.

Procedural Matters – Confidentiality

As an interim measure and consistent with OPG's request, counsel and consultants for intervenors that wish to review the information (excluding the OEB Review Only document) for which either OPG, Candu, BWXT or SNC/AECON JV are seeking confidential treatment may do so after signing a copy of the OEB's Declaration and Undertaking, filing it with the OEB and providing a copy to OPG and the related counterparties to the subject contract. If any of OPG, Candu, BWXT or SNC/AECON JV has any objections with respect to sharing confidential information with any party that has signed the Declaration & Undertaking it must immediately and within 5 days from the receipt of the signed Declaration and Undertaking file its objections with the OEB and copy the relevant party. If the party to whom the objection is directed wishes to respond to the objection, it must file its reply within 5 days from the receipt of the objection.

Parties may make submissions on whether the information for which OPG, SNC/AECON JV, BWXT or Candu, respectively, are requesting confidential treatment, but excluding the OEB Review Only document and the 2014 Tax Returns, should be treated confidentially in accordance with the steps described below. The OEB will issue a decision on the confidential status of the information once it has considered any submissions.

Application Presentation

OPG requested an opportunity to present an overview of the key strategic and technical aspects of the application in its cover letter to the application.

The OEB is making provision for an untranscribed presentation of the application to the OEB panel, prior to interrogatories as set out in the order below. While parties to this proceeding as well as OEB staff may attend the presentation, the purpose of the presentation is not to provide an opportunity for cross-examination, but rather for OPG to present an overview of its application to the OEB panel and to respond to any questions of clarification.

Untranscribed Technical Conference

At this time, provision is being made for an untranscribed technical conference on the Darlington Refurbishment Program (DRP) and the rate smoothing deferral account. OPG shall make a presentation on the DRP contracts, schedule and cost in the 2017-2020 period as well as for the full DRP, and the mechanics of the rate smoothing deferral account, to the parties as set out in the order below. Parties may request presentation of additional aspects of the DRP and rate smoothing deferral account prior to the conference. The OEB panel hearing the application will be in attendance.

The purpose of the conference is to provide an opportunity for all parties to have a sufficiently robust understanding of these two matters which will focus the examination of this major capital project and new account.

Interrogatories

Written interrogatories and interrogatory responses shall be filed as set out in the order below.

Parties should not engage in detailed exploration of items that do not appear to be material. Parties should use the materiality thresholds documented in the Filing Guidelines for OPG as a guide. In making its decision on cost awards, the OEB will consider whether intervenors made reasonable efforts to ensure that their participation in the hearing was focused on material issues.

Parties must provide evidence references and sort their interrogatories and responses by issue. Parties should consult sections 26 and 27 of the OEB's Rules of Practice and Procedure regarding required naming and numbering conventions and other matters related to interrogatories.

Technical Conference

A technical conference will be held to provide for clarification on interrogatory responses as set out in the order below. In preparation for the transcribed technical conference, the OEB will require parties to file a description of the specific areas that they will be focussing on and an estimate of time required for each area of focus. This will allow a conference schedule to be developed. If parties wish to file specific questions in advance, they may do so.

Schedule of Procedural Steps

The balance of procedural steps, including provision for motions for further and better answers, the filing of OEB staff and intervenor evidence, a settlement conference and the oral hearing are set out in the orders below.

The schedule for all the procedural steps for this proceeding is summarized in a table in Schedule C to this Procedural Order.

While there is some uncertainty with respect to the specific dates in the schedule, the OEB believes that it is helpful to provide this information to all parties at this time as a general guide for planning purposes. Unless otherwise directed by the OEB, parties should plan toward these dates.

The OEB considers it necessary to make provision for the following matters related to this proceeding.

IT IS THEREFORE ORDERED THAT:

Issues List

1. OEB staff and intervenors may make submissions on the draft issues list at Schedule B to this Procedural Order, and shall file any submissions with the OEB and deliver them to all parties no later than **August 31, 2016.**

2. OPG may respond to the submissions of intervenors. Similarly, all other parties may respond to the submission of other parties. Those responses shall be filed with the OEB and delivered to all parties no later than **September 9, 2016**.

Confidentiality

1. Candu and BWXT shall immediately and within 5 days of the date of this Order, inform the OEB if they wish to participate in this proceeding.

2. If Candu is seeking confidential treatment for the SG EPC Contract in its entirety, then pursuant to section 5.1.4 (c)(ii) of the Practice Direction, Candu is directed to prepare a summary of the SG EPC Contract for the public record and to file with the OEB on or before **August 24, 2016.**

3. If Candu is seeking confidential treatment for portions of the SG EPC Contract, then pursuant to section 5.1.4 (c)(i) of the Practice Direction, OPG and Candu are directed to jointly file a redacted version of the SG EPC Contract on the public record, on or before **August 24, 2016**. At that time, Candu shall also file with the OEB an un-redacted version of the SG EPC Contract for the confidential record identifying the redactions it is proposing.

4. Pursuant to section 5.1.4 (a) of the Practice Direction, OPG and Candu shall file with the OEB, on or before **August 24, 2016**, their respective reasons for the confidentiality request pertaining to the SG EPC Contract, including the reasons

why the information should be treated as confidential and the reasons why public disclosure of that information would be detrimental.

5. SNC/AECON JV shall file with the OEB, on or before **August 24, 2016**, its reasons for the confidentiality request pertaining to the information contained in the contracts it has entered into with OPG, including the reasons why the information should be treated as confidential and the reasons why public disclosure of that information would be detrimental.

6. As an interim measure, counsel and consultants for intervenors that wish to review the information (excluding the OEB Review Only document) for which either OPG, BWXT, Candu or SNC/AECON JV are seeking confidential treatment may do so after signing a copy of the OEB's Declaration and Undertaking, filing it with the OEB, and providing a copy to OPG. If any of OPG, Candu, BWXT or SNC/AECON JV has objections with respect to sharing confidential information with any party that has signed the Declaration & Undertaking, it must file its objections with the OEB and provide a copy to the party whom the objection relates, within 5 days from the date the Declaration and Undertaking is filed with the OEB. The party to whom the objection relates must file its reply with the OEB, within 5 days from date the objection is filed with the OEB.

7. Parties wishing to make submissions on the request for confidential treatment requests pertaining to information in the 2016-2018 Business Plan, Business Planning Instructions, Revenue Comparison Tables, Concentric Cost of Capital Engagement Letter, BCSs, and the DRP Attachments, shall file such submissions with the OEB and deliver them to OPG and the party that has requesting confidential treatment and all other parties on or before **August 31, 2016**. Parties are reminded that the OEB is not accepting submissions on the 2014 Tax Returns and the "OEB Review Only" document.

8. If the party (i.e OPG, SNC/AECON JV or Candu) requesting confidential treatment wishes to respond to the submissions directed to it, it shall file such submissions with the OEB and deliver them to the relevant intervenor and all other parties on or before **September 9, 2016**.

Application Presentation

9. An untranscribed presentation of the application will be held on **September 1, 2016** starting at 9:30 a.m. 2300 Yonge Street, 25th floor, Toronto for OPG to present its application to the OEB.

Untranscribed Technical Conference

10. An untranscribed technical conference on the Darlington Refurbishment Program and the rate smoothing deferral account will be held on **September 23, 2016** starting at 9:30 a.m. 2300 Yonge Street, 25th floor, Toronto. OPG shall make a presentation on these matters and intervernors and OEB staff may request presentation of information that is in addition to contracts, schedule and cost in the 2017-2020 period as well as for the full project by **September 16, 2016**.

Interrogatories

11. OEB staff shall request any relevant information and documentation from OPG that is in addition to the evidence already filed, by written interrogatories filed with the OEB and served on all parties by **September 26, 2016**.

12. Intervenors shall request any relevant information and documentation from OPG that is in addition to the evidence already filed, by written interrogatories filed with the OEB and served on all parties by **October 3, 2016**.

13. OPG shall file with the OEB complete written responses to all interrogatories and serve them on all intervenors and OEB staff by **October 26, 2016**.

14. OPG, OEB staff and intervenors may make submission on the prioritization of the issues list and shall file those submissions with the OEB and serve them on all intervenors and OEB staff by **November 9, 2016**.

15. OPG, OEB staff and intervenors may respond to all submissions of other parties. Those responses shall be filed with the OEB and served on all intervenors and OEB staff by **November 14, 2016**.

Technical Conference

16. A transcribed technical conference will be held on **November 14, 2016** starting at 9:30 a.m. 2300 Yonge Street, 25th floor, Toronto. If necessary, the technical conference will continue on November 15, 2016. Intervenors shall file with the

OEB a description of the subject areas they will focus on at the technical conference, and time estimates by **November 10, 2016**.

17. Any technical conference undertakings shall be file with the OEB no later than **November 21, 2016**.

OEB Staff and Intervenor Evidence

18. OEB staff shall inform the OEB by letter of their plans to file expert evidence in this proceeding by **September 14, 2016**. Intervenors shall inform the OEB by letter of their plans to file expert evidence in this proceeding, and the estimated costs including assumptions regarding the participation of the expert in the proceeding and incremental time that will be spent by the intervenor's counsel or any other consultant(s) in relation to the expert evidence by **September 14, 2016.**

19. If OEB staff or any intervenor would like to file evidence that is relevant to this proceeding, that evidence shall be filed with the OEB, and copied to OPG and intervenors, by **November 21, 2016**.

20. If any party is seeking information and material with respect to any evidence filed by OEB staff or any intervenor that is in addition to the evidence filed with the OEB, and that is relevant to this proceeding, that information shall be requested by written interrogatories filed with the OEB, and copied to OPG and intervenors, by **November 30, 2016**.

21. Any party that receives interrogatories on its evidence shall file with the OEB complete responses to the interrogatories and copy the responses to OPG and intervenors by **December 12, 2016**.

Motion Hearing

22. In the event that motions, including for further and better answers, are filed in this proceeding, the motions will be heard on **December 16, 2016** starting at 9:30 a.m. 2300 Yonge Street, 25th floor, Toronto.

Settlement Conference

23. A Settlement Conference among the parties and OEB staff, for those issues that have not been deemed oral hearing issues, will be convened on **January 9, 2017** starting at 9:30 a.m., at 2300 Yonge Street, 25th floor, Toronto. The parties and

OEB staff will only consider those issues that If necessary, the Settlement Conference will continue on January 10 and 11, 2017.

24. Any settlement proposal arising from the Settlement Conference shall be filed with the OEB on or before **January 30, 2017**.

25. Any submission from OEB staff on a settlement proposal shall be filed with the OEB and served on all parties on or before **February 10, 2017**.

Oral hearing

26. The oral hearing for this proceeding will begin on **February 21, 2017** starting at 9:30 a.m., at 2300 Yonge Street, 25th floor, Toronto. Any settlement proposal resulting from the settlement conference will be presented to the OEB on this day. The oral hearing will continue for additional days as determined by the OEB, for unsettled primary issues and for issues deemed oral hearing only. Parties are advised that the OEB will not sit for hearing days on Wednesdays or on any day during the weeks of March 13 and March 20, 2017. The hearing will resume on Tuesday, March 28, 2017 and continue thereafter, as required.

All filings to the OEB must quote the file number, **EB-2016-0152**, be made in searchable / unrestricted PDF format electronically through the OEB's web portal at https://www.pes.ontarioenergyboard.ca/eservice/. 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 http://www.ontarioenergyboard.ca/OEB/Industry. 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 CD in PDF format, along with two paper copies. Those who do not have computer access are required to file 7 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.

With respect to distribution lists for all electronic correspondence and materials related to this proceeding, parties must include the Case Manager, Violet Binette at violet.binette@ontarioenergyboard.ca and OEB Counsel, Michael Millar at michael.millar@ontarioenergyboard.ca.

ADDRESS

Ontario Energy Board
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Attention: Board Secretary

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DATED at Toronto, **August 12, 2016**

ONTARIO ENERGY BOARD

By delegation, before: Kristi Sebalj

Original signed by

Kristi Sebalj
Registrar

Schedule A
Ontario Power Generation Inc.
EB-2016-0152

APPLICANT & LIST OF INTERVENORS

August 12, 2016

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August 12, 2016

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Ontario Association of Physical Plant Administrators	**Scott Walker** President and CEO E2 Energy Inc. 104-6711 Mississauga Rd. Mississauga ON L5N 2W3 Tel: 905-542-2250 Ext: 222 Fax: 905-542-8250 swalker@e2energyinc.com

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August 12, 2016

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August 12, 2016

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Schedule A
Ontario Power Generation Inc.
EB-2016-0152

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Schedule A
Ontario Power Generation Inc.
EB-2016-0152

APPLICANT & LIST OF INTERVENORS

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Schedule A
Ontario Power Generation Inc.
EB-2016-0152

APPLICANT & LIST OF INTERVENORS

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Schedule B

Ontario Power Generation Inc.
2017-2021 Payment Amounts for
Prescribed Generating Facilities
EB-2016-0152

DRAFT ISSUES LIST (NON-PRIORITIZED)

1. GENERAL

1.1 Has OPG responded appropriately to all relevant Board directions from previous proceedings?

1.2 Are OPG's economic and business planning assumptions appropriate for the nuclear assets?

1.3 Is the overall increase in nuclear payment amounts reasonable given the overall bill impact on customers?

2. RATE BASE

2.1 Are the amounts proposed for nuclear rate base appropriate?

3. CAPITAL STRUCTURE AND COST OF CAPITAL

3.1 Are OPG's proposed capital structure and rate of return on equity appropriate?

3.2 Are OPG's proposed costs for the long-term and short-term debt components of its capital structure appropriate?

4. CAPITAL PROJECTS

4.1 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 Are the proposed nuclear capital expenditures and/or financial commitments reasonable?

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

4.4 Are the proposed test period in-service additions for the Darlington Refurbishment Program appropriate?

5. PRODUCTION FORECASTS

5.1 Is the proposed nuclear production forecast appropriate?

6. OPERATING COSTS

6.1 Is the test period Operations, Maintenance and Administration budget for the nuclear facilities appropriate?

6.2 Are the benchmarking results and targets flowing from OPG's nuclear benchmarking reasonable?

6.3 Is the forecast of nuclear fuel costs appropriate?

6.4 Is the test period Operations, Maintenance and Administration budget for the Darlington Refurbishment Program appropriate?

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

Corporate Costs

6.6 Are the test period human resource related costs for the nuclear facilities (wages, salaries, benefits, incentive payments, FTEs and pension costs) appropriate?

6.7 Are the corporate costs allocated to the nuclear businesses appropriate?

6.8 Are the centrally held costs allocated to the nuclear business appropriate?

Depreciation

6.9 Is the proposed test period nuclear depreciation expense appropriate?

Income and Property Taxes

6.10 Are the amounts proposed to be included in the test period nuclear revenue requirement for income and property taxes appropriate?

Other Costs

6.11 Are the asset service fee amounts charged to the nuclear businesses appropriate?

7. OTHER REVENUES

Nuclear

7.1 Are the forecasts of nuclear business non-energy revenues appropriate?

Bruce Nuclear Generating Station

7.2 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 Is the revenue requirement impact of the nuclear liabilities appropriately determined?

9. DEFERRAL AND VARIANCE ACCOUNTS

9.1 Is the nature or type of costs recorded in the deferral and variance accounts appropriate?
9.2 Are the balances for recovery in each of the deferral and variance accounts appropriate?
9.3 Are the proposed disposition amounts appropriate?
9.4 Is the disposition methodology appropriate?
9.5 Is the proposed continuation of deferral and variance accounts appropriate?
9.6 Are the deferral and variance accounts that OPG proposes to establish appropriate?

10. REPORTING AND RECORD KEEPING REQUIREMENTS

10.1 Are the proposed reporting and record keeping requirements appropriate?

11. METHODOLOGIES FOR SETTING PAYMENT AMOUNTS

11.1 Has OPG responded appropriately to OEB direction on establishing incentive regulation?
11.2 Is the design of the regulated hydroelectric and nuclear payment amounts appropriate?
11.3 Is OPG’s proposal for smoothing nuclear payment amounts consistent with O. Reg. 53/05?

12. IMPLEMENTATION

12.1 Are the effective dates for new payment amounts and riders appropriate?

Schedule C

Table of Procedural Steps

Procedural Step	Date
OPG/Candu - filings and reasons re confidentiality	August 24, 2016
SNC/Aecon JV - reasons for confidentiality	August 24, 2016
Submissions on issues	August 31, 2016
Submissions on confidentiality	August 31, 2016
Untranscribed Application Presentation	September 1, 2016
Reply submissions on issues	September 9, 2016
Reply submissions on confidentiality	September 9, 2016
Letter from parties - expert evidence	September 14, 2016
Letter from parties - untranscribed technical conf	September 16, 2016
Untranscribed Technical Conference	September 23, 2016
Interrogatories Issued OEB Staff	September 26, 2016
Interrogatories issued by intervenors	October 3, 2016
Applicant's response to interrogatories	October 26, 2016
Submissions on issue prioritization	November 9, 2016
Letter from parties - tech conf areas and times	November 10, 2016
Transcribed Technical Conference	November 14, 2016
Reply submissions on issue prioritization	November 14, 2016
Technical Conference Undertakings	November 21, 2016
OEB Staff and Intervenor Evidence	November 21, 2016
Interrogatories on Evidence	November 30, 2016
Responses to Interrogatories	December 12, 2016
Motion Hearing	December 16, 2016
Settlement Conference	January 9, 2017
Filing of Settlement Proposal	January 30, 2017
OEB staff submission on settlement proposal	February 10, 2017
Oral Hearing	February 21, 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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2017-2021 Payment Amounts
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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.

IMPACT STATEMENT

1.0 PURPOSE

The purpose of this exhibit is to show the impact of certain material changes that have occurred since OPG submitted its pre-filed evidence in this Application on May 27, 2016, consistent with the requirements of paragraph 11.02 of the OEB's *Rules of Practice and Procedure*. These changes impact the revenue requirement for the nuclear facilities and result from (i) OPG's 2017-2019 business plan (the "2017-2019 Business Plan"), which includes an updated forecast of pension and other post-employment benefit ("OPEB") cash amounts, projected cost impacts of the 2017 to 2021 ONFA Reference Plan approved by the Province in December 2016 (the "2017 ONFA Reference Plan")[1], and new Canadian Nuclear Safety Commission ("CNSC") requirements; (ii) an updated forecast of used fuel and low and intermediate level ("L&ILW") revenues under the Bruce lease and associated agreements ("Bruce Lease") that was finalized subsequent to the approval of the 2017-2019 Business Plan; and (iii) the Return on Equity ("ROE") value of 8.78% published by the Ontario Energy Board ("OEB") on October 27, 2016 for use in 2017 custom IR applications (collectively, the "Drivers").[2]

The Application was filed based on OPG's 2016-2018 Business Plan, which also included a financial projection for the 2019-2021 period (Ex. A2-2-1). The 2017-2019 Business Plan was approved by OPG's Board of Directors ("OPG Board") on November 10, 2016 and includes a financial projection for the 2020-2021 period. The five-year planning information included in the 2017-2019 Business Plan was developed as part of the 2017-2019 business planning cycle, applying a consistent process for all years. A copy of the 2017-2019

[1] See Attachment 4 for a copy of the letter from the Province approving the 2017-2021 ONFA Reference Plan.

[2] See Ontario Energy Board Web Posting, "*Cost of Capital Parameter Updates for 2017 Cost of Service and Custom Incentive Rate-setting Applications*", dated October 27, 2016 at http://www.ontarioenergyboard.ca/oeb/_Documents/2017EDR/OEB_Ltr_Cost_of_Capital_Update_20161027.pdf

Business Plan is provided in Attachment 1[3]. Attachment 1 is being filed in accordance with the requirements of the OEB's practice directions on confidential filings.

2.0 SUMMARY

This update to the Application reflects material changes in costs for the nuclear facilities in the 2017 to 2021 IR period resulting from the Drivers. In determining items to be included as part of this update, OPG evaluated changes with reference to a materiality threshold of an average $10M per year over the IR period. As shown in Chart 2.0 below, the changes in this update result in an overall net increase in the nuclear revenue requirement of approximately $7M in total for the IR period. The updated cost forecasts were determined using the same rigour and, unless otherwise noted in this Impact Statement, using the same methodologies as the original pre-filed evidence. OPG is not updating its nuclear production forecast, as there is no material change to that forecast in the 2017-2019 Business Plan. An updated Revenue Requirement Work Form reflecting the changes identified in this Impact Statement is attached as Attachment 2.

The update to the revenue requirement does not impact OPG's smoothing proposal of a constant 11 percent per year nuclear base rate increase. There are also no changes to the proposed deferral and variance account amortization amounts. As a result, OPG is not updating its request for smoothed nuclear payment amounts or riders, and there is no change to the annualized residential consumer impact of OPG's Application.

In addition to revenue requirement items, OPG is updating its forecast of pension and OPEB accrual costs attributed to the nuclear facilities for the IR period provided in the Application, to reflect the 2017-2019 Business Plan. As discussed in Ex. F4-3-2, OPG proposes to continue recording the difference between actual accrual costs and actual cash amounts for pension and OPEB in the Pension & OPEB Cash Versus Accrual Differential Deferral Account, pending the outcome of the OEB's EB-2015-0040 consultation.

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[3] A copy of OPG's 2017-2019 Business Planning Instructions can be found at Ex. L-1.2-1 Staff-003.

OPG is proposing to update the 2017 to 2021 nuclear revenue requirement in the following five areas, as discussed in greater detail in section 3.0:

- changes to forecast pension and OPEB cash amounts, including the impact of the latest filed pension funding valuation as of January 1, 2016 and an assumed subsequent valuation as of January 1, 2019 (see section 3.1);
- changes to forecast costs associated with OPG's liabilities for nuclear waste management and decommissioning ("nuclear liabilities"), including the projected impact of the 2017 ONFA Reference Plan effective January 1, 2017[4], as well as the income tax impacts of changes to forecast cash expenditures on nuclear waste management and decommissioning and corresponding disbursements from the nuclear segregated funds (see section 3.2);
- changes to Bruce Lease net revenues and related tax effects as a result of an updated forecast of used fuel and L&ILW revenues, under the amended Bruce Lease, for changes in revenue rates reflecting the 2017 ONFA Reference Plan cost estimates and new waste volume forecasts provided by Bruce Power LP (see section 3.3);
- an update to the forecast ROE amounts and related tax effects to reflect the most recent OEB-published Cost of Capital parameters (see section 3.4); and
- an increase in forecast Nuclear base OM&A costs resulting from new Fitness for Duty requirements from the CNSC (see section 3.5).

There are two consequential changes to the nuclear revenue requirements, also presented in Chart 2.0, as a result of the five changes identified above:

- an increase in nuclear stretch factor dollars as a result of the changes in Nuclear OM&A included in this Impact Statement; and
- the elimination of IR period regulatory tax loss carry forwards, as a result of the changes in regulatory taxable income arising from the items included in this Impact Statement (see section 3.6).

[4] Any difference between the projected impacts and the final impacts for the prescribed facilities arising from the approved 2017 ONFA Reference Plan will be recorded in the Nuclear Liability Deferral Account. Any such differences related to the Bruce facilities will be recorded in the Bruce Lease Net Revenues Variance Account.

Chart 2.0

Summary of Changes to Proposed Nuclear Revenue Requirement* ($M)

Line No.		2017	2018	2019	2020	2021	Total
1	Pension and OPEB Cash Amounts	19.1	18.3	53.8	81.0	79.3	251.5
2	Nuclear Liabilities	(40.3)	(57.2)	(21.0)	(121.2)	(156.0)	(395.6)
3	Used Fuel and Waste Services Bruce Lease Revenue	35.1	35.6	36.5	37.6	34.9	179.8
4	Return on Equity Value	(9.0)	(9.4)	(9.2)	(20.1)	(21.3)	(69.0)
5	New CNSC Requirements (Base OM&A)	0.5	0.5	16.7	11.7	11.7	41.0
6	Nuclear Stretch Dollars**	-	(0.0)	(0.1)	(0.1)	(0.2)	(0.5)
7	Tax Carryforwards	6.4	(15.2)	(52.0)	60.8	-	(0.0)
8	**Total Revenue Requirement Change**	11.9	(27.4)	24.6	49.6	(51.6)	7.1

*all amounts shown are inclusive of any income tax impacts; positive values are increases to revenue requirement and negative values are decreases
**reflects changes in Nuclear base OM&A due to new CNSC requirements and changes in nuclear liabilities costs

The updated nuclear requirement is provided in Ex. N1-1-1 Table 1. In order to minimize the impact on the proceeding schedule and to keep the Impact Statement to a manageable size, OPG is limiting the update to the changes described above.

The change in forecast pension and OPEB cash amounts for the nuclear facilities increases the nuclear revenue requirement by approximately $252M over the IR period. This is due to higher payments for pension deficit funding projected in the 2017-2019 Business Plan, primarily as a result of a decrease in discount rates relative to the pre-filed evidence. The forecast nuclear pension and OPEB accrual costs decrease by approximately $21M over the IR period. The 2017 to 2021 forecast excess of pension and OPEB accrual costs over cash amounts decreases to approximately $130M for the nuclear facilities, compared to approximately $403M in the pre-filed evidence.

Changes in forecasts related to nuclear liabilities decrease the IR period nuclear revenue requirement by approximately $396M, which consists of a decrease of approximately $551M related to the changes in nuclear liabilities costs for the Bruce facilities, an increase of approximately $280M associated with the changes in nuclear liabilities costs for the prescribed facilities, and a decrease of approximately $124M in income tax impacts related to changes in forecast cash expenditures on nuclear waste management and decommissioning and associated disbursements from the nuclear segregated funds.

The change in Bruce Lease net revenues as a result of updated used fuel and L&ILW revenue forecasts increases the nuclear revenue requirement by approximately $180M over the IR period, which consists of a $135M reduction in Bruce Lease net revenues and $45M in increased income tax impacts.

OPG is updating its ROE for all years of the IR period using the prevailing 2017 ROE as specified by the OEB[5]. The 2017 ROE value is 8.78%, which is 0.41% lower than the ROE value underpinning the pre-filed evidence. The change in ROE decreases the 2017 to 2021 nuclear revenue requirement by approximately $69M, inclusive of the related income taxes.

The new CNSC Fitness for Duty regulatory requirements will create an obligation for OPG to design and implement a Fitness for Duty program. OPG expects to incur Nuclear base OM&A costs of approximately $41M for implementation of this program during the IR period. Based on the regulatory significance of this new CNSC requirement, OPG has included this item as part of its update. These costs exceed $10M per year, for each year compliance is assumed to be required by the CNSC during the IR period (2019-2021).

As discussed in section 4.0, the above changes impact the nuclear revenue requirement and nuclear rate base approvals sought by OPG in Ex. A1-2-2, as well as the resulting portion of the annual nuclear revenue requirement OPG proposes to defer in the Rate Smoothing Deferral Account over the IR period.

3.0 ITEMS INCLUDED IN THE IMPACT STATEMENT

This section provides additional detail on each of the five changes reflected in the revised nuclear revenue requirement requested for the IR period. In addition, it presents the change in forecast pension and OPEB accrual costs for the period, to provide a forecast of the

[5] See footnote 1.

SECOND IMPACT STATEMENT

1.0 PURPOSE

The purpose of this exhibit is to show the impact of certain material changes that have occurred since OPG filed the first Impact Statement (Ex. N1-1-1) on December 20, 2016, consistent with the requirements of paragraph 11.02 of the OEB's *Rules of Practice and Procedure*. These changes impact the revenue requirement for the nuclear facilities and result from the need to exclude forecast capital in-service amounts for the Heavy Water Storage and Drum Handling Facility Project ("D2O Project") relating to the Darlington Refurbishment Program ("DRP") from the scope of OPG's Application.

2.0 SUMMARY

This update to the Application is required to reflect material changes in costs for the nuclear facilities in the 2017 to 2021 incentive rate-setting ("IR") period. These changes are driven by the fact that OPG is no longer seeking OEB approval of the forecast capital in-service amounts for the D2O Project, which was described in the pre-filed evidence as one of the Facilities & Infrastructure Projects ("F&IP") for the DRP (Ex. D2-2-10, s. 2.4; Tables 1, 2, 4 and 5; and Attachment 1, Tab 1).

The purpose of the D2O Project is to provide a heavy water storage and processing facility for the removal of heavy water from the Darlington units during refurbishment as well as a long-term solution for the management of heavy water during normal operations. In light of the tremendous complexity and scale associated with this first of its kind facility, certain circumstances relating to the detailed engineering design of the D2O Project have recently arisen that are expected to impact the forecast in-service date and may impact the in-service amounts for the project. OPG is actively reviewing the engineering design, including retaining third party expert advisors to assist in this regard.

Given the present uncertainty associated with the D2O Project, OPG is amending its evidence in this proceeding to exclude the capital in-service amounts for the D2O Project forecast to occur during the 2017 to 2021 period, and to revise the revenue requirement accordingly. The actual revenue requirement impact of the D2O Project will be recorded in the nuclear portion of the Capacity Refurbishment Variance Account ("CRVA") once the project enters into productive service. Such entries into the CRVA will continue to be recorded until the OEB-approved D2O Project in-service amount is reflected in the revenue requirement through a subsequent rate setting process. The OEB will have the opportunity to conduct a prudence review in respect of the D2O Project after it has been completed and placed into service. This approach is consistent with the OEB's Decision with Reasons in EB-2013-0321[1]. The prudence review of the D2O Project is expected to occur at the mid-term review in the first half of 2019. The in-service amount determined by the OEB as a result of that review will provide the basis for determining the revenue requirement impacts that will be recorded in the CRVA until the OEB approved unamortized in-service D2O Project amount is reflected in revenue requirements in a subsequent rate setting process.

3.0 ITEMS INCLUDED IN THE IMPACT STATEMENT

This section provides additional detail on the changes reflected in the revised revenue requirement requested for the IR period.

The impact on the nuclear revenue requirement from removing the projected in-service amounts for the D2O Project is $(40.4)M in 2017, $(36.9)M in 2018, $(36.4)M in 2019, $(40.9)M in 2020 and $(40.1)M in 2021, as shown in Chart 1 below.

[1] EB-2013-0321 Decision with Reasons, page 59.

THIRD IMPACT STATEMENT

1.0 PURPOSE

The purpose of this exhibit is to reflect the impact of material changes made to the regulation governing the rate smoothing proposal in this application. This evidence sets out a revised rate smoothing proposal in accordance with O. Reg. 53/05 (the "Regulation") as amended on March 2, 2017.[1] The regulatory changes impact the rate smoothing evidence (section 2 of Ex. A1-3-3), with consequential impacts on OPG's deferral and variance accounts (Ex. H1-1-1), Revenue Requirement Work Form (Ex. I1-1-1, Attachment 1), consumer impact evidence (Ex. I1-1-2) and Nuclear Payment Amounts (Ex. I1-3-1).

Consistent with the previously filed Impact Statements (Ex. N1-1-1 and Ex. N2-1-1), OPG has consolidated the relevant updates to its evidence in this exhibit.

2.0 OVERVIEW OF REVISED RATE SMOOTHING PROPOSAL

Before the amendments, the Regulation required smoothing the annual changes in OPG's <u>nuclear payment amounts</u>.[2] Under the amended Regulation, the objective of rate smoothing is to make more stable the <u>total OPG weighted average payment amounts</u> ("WAPA")[3] during the deferral period[4] by adjusting the nuclear payment amounts within the WAPA. So, while nuclear payment amounts continue to be the aspect of OPG's rates that is adjusted under the amended Regulation, the objective of those adjustments is now to produce a more stable change in the total OPG WAPA. These adjustments to the nuclear payment amounts ultimately determine the annual amounts of nuclear revenue requirement to be deferred and recorded in the rate smoothing deferral account ("RSDA") established pursuant to the Regulation.

---

[1] A copy of the amended Regulation is provided as Attachment 1 to this schedule.
[2] As described in Ex. A1-3-3, Section 2.0.
[3] The WAPA includes both hydroelectric and nuclear payment amounts and payment riders. Section 0.1(1) of the amended O. Reg. 53/05 prescribes how WAPA is to be calculated.
[4] As defined in s. 0.1(1) of O. Reg. 53/05, the deferral period is "the period beginning on January 1, 2017, and ending when the Darlington Refurbishment Project ends".

Under the amended Regulation, rate smoothing continues to be directed at managing the annual impact on customers during the deferral period. Absent smoothing, the rate impact and volatility in the 2017-2021 period are driven by reduced production as Darlington units are taken out of service to be refurbished, partially offset by production at the Pickering generating station in 2021 due to the plan to extend operations, and costs associated with the Darlington Refurbishment Program. The amended Regulation changes the method by which nuclear revenue requirement is distributed throughout the deferral period. Relative to OPG's original proposal (Ex. A1-3-3, section 2.0), rate smoothing based on WAPA will result in a more stable year-over-year change in customers' bills, which OPG believes will benefit customers.

Section 3.0 of this schedule provides a detailed description of the changes in the amended Regulation. Section 4.0 provides changes to the rate smoothing considerations discussed in Ex. A1-3-3, section 2.3. Section 5.0 describes the inputs into the calculation of the WAPA and the customer bill impact calculation.

Section 6.0 sets out OPG's proposal and alternatives considered. OPG proposes that the average annual change in WAPA during the 2017 to 2021 period be 2.5% (the "smoothed rate"), which would result in a cumulative deferred revenue requirement of approximately $1B in that period.[5] This proposal would result in an average annual increase of $0.65 on the typical residential customer's monthly bill during the 2017 to 2021 period, compared to the average annual increase of $1.05 proposed under the previous revision of the Regulation.

Section 7.0 discusses implementation of rate smoothing, and Section 8.0 provides an update to certain interrogatories and undertakings to reflect the revised rate smoothing proposal. Section 9.0 updates the Approvals OPG is seeking, as reflected in the updated version of Ex. A1-2-2 that OPG has filed.

---

[5] Annual deferred amounts are provided in Chart 4. The deferred amount excludes interest of approximately $0.12B based on OPG's annual long-term debt rates as discussed in Ex. C1-1-2.

Ontario Energy Board

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BY E-MAIL

May 19, 2017

Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto ON M4P 1E4

Dear Ms. Walli:

Re: Ontario Power Generation Inc.
2017-2021 Payment Amounts
Ontario Energy Board File Number EB-2016-0152

In accordance with Procedural Order No. 8, please find attached OEB staff's submission in the above noted proceeding. OPG and all intervenors have been copied on this filing.

OEB staff has made every attempt to complete the submission without referring directly to confidential materials. However, there are some confidential materials in the submission, which have been redacted. Schedule B to the submission contains the un-redacted text, and will be circulated to those parties that are eligible to receive it. OEB staff asks that OPG review the materials that OEB staff has redacted and advise if any of this information can be placed on the public record.

Yours truly,

Original signed by

Violet Binette
Project Advisor, Applications

Attach

ONTARIO POWER GENERATION INC.

2017-2021 PAYMENT AMOUNTS

EB-2016-0152

Ontario Energy Board

Staff Submission

May 19, 2017

Again, the figure reflects, for illustrative purposes, the various other recommendations set out in this submission, including disallowances, as though they were approved by the OEB. Depending on what the OEB actually approves on an unsmoothed basis, the specifics regarding smoothing might change. That is, the edges to be rounded off might be different. As OPG notes in its AIC, smoothing depends on a number of interrelated decisions.[520] For that reason, OEB staff supports OPG's suggestion that the OEB hold off on making a decision on smoothing until the payment amount order stage. The OEB could direct OPG to provide an updated smoothing proposal based on the OEB's findings and reflecting whatever smoothing principles the OEB determines are appropriate.

12. IMPLEMENTATION

Issue 12.1 (Primary) - Are the effective dates for new payment amounts and riders appropriate?

The application filed on May 27, 2016, seeks approval for nuclear payment amounts to be effective January 1, 2017 and for each following year through to December 31, 2021. The request 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 amount for the period January 1, 2017 to December 31, 2021. OPG also requested riders, January 1, 2017 to December 31, 2018, to clear 2015 year end balances in certain deferral and variance accounts.

On December 8, 2016, the OEB made OPG's current payment amounts for the regulated hydroelectric and nuclear facilities interim pending the OEB's final decision.

OEB staff submits that a January 1, 2017 effective date for payment amounts is reasonable. The application was filed shortly after audited results for 2015 were available. As OPG states in the AIC, OPG has met the deadlines established by the OEB in Procedural Order No. 1, issued on August 12, 2016.

Should the OEB consider an effective date other than January 1, 2017, OEB staff notes OPG's position described in undertaking J23.1, which is that the difference between the approved nuclear revenue requirement in this proceeding, and the current interim payment amounts would be recorded in the RSDA from January 1, 2017 up to the effective date determined by the OEB. Although OEB staff supports OPG requested effective date of January 1, 2017, to the extent the OEB selects a different date OEB

[520] AIC page 14.

staff does not believe that the RSDA should be used to record any differences between the (now) current rates and new rates for that “stub” period. The purpose of the RSDA (and the regulation that created the RSDA) is to allow for whatever smoothing the OEB deems to be appropriate to make more stable the year over year changes to OPG’s weighted payment amounts. It does not relate to the OEB’s selection of the appropriate effective date. If the OEB selects an effective date other than January 1, it should be clear that any revenues that are forgone on account of the effective date should not be recorded in the RSDA.

As noted in section 11.4 regarding rate smoothing, OEB staff submits that the OEB can consider an effective date other than January 1, 2017 for the deferral and variance account riders.

- All of which is respectfully submitted -

EB-2016-0152

ONTARIO ENERGY BOARD

Ontario Power Generation Inc. 2017 – 2021 Payment Amounts Application
for OPG's Prescribed Facilities

Submissions on Behalf of the
QUINTE MANUFACTURERS ASSOCIATION

May 29, 2017

9.0 PAYMENT AMOUNT SMOOTHING

From a business planning perspective, the general concept of rate smoothing gives some sense of certainty in terms of electricity rates going forward. However, recovering the costs of the of the DRP by delaying rate impacts for the DRP into the future causes a business planning problem for QMA members and the Concentric expert identified the concern:[26]

> *"And what they [OPG] are doing is taking the rate impacts of the Darlington project and smoothing them over a longer period, so that they can lower the impact to rates on the front end over the rate setting period included, but eventually they'll have to be higher at the back end, post this rate setting period, in order to fully account for the project."*
>
> *"But the overall rate impacts are being smoothed over time, so as to tilt the rates to make them lower today than they will be in the future."*

The challenge for QMA members is the reality of ever increasing rates. The QMA supports Board staff's analysis of OPG's payment amount smoothing proposal and agrees that the Board consider staff's alternative smoothing proposal as discussed in their submission dated May 19, 2017. [27]

10.0 IMPLEMENTATION

The QMA does not oppose the effective date for the new nuclear payment amounts beginning January 1, 2017 and hydroelectric amounts on the same date and recognizes OPG's current payment amounts were made interim on December 8, 2016 pending the Boards decision in this proceeding.

11.0 CONCLUSIONS

This was a very large and complex proceeding with a substantial amount of evidence, interrogatories and testimony to review and digest. As a result of this proceeding, the QMA

[26] TR Vol. 18 pg. 59
[27] Board Staff Submission, May 19, 2017, pg. 178

29th May, 2017

Matthew Kellway
Special Assistant to the President & Manager, Central Functions
The Society of Energy Professionals
2239 Yonge St
Toronto, ON M4S 2B5

VIA Canada Post and RESS Filing

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge St.
Toronto, ON
M4P 1E4

Re: EB-2016-0152 Ontario Power Generation Inc.
2017-2021 Payment Amounts Application
<u>The Society of Energy Professionals' Final Submissions</u>

Dear Ms. Walli,

As per the schedule outlined in the OEB's procedural order no. 8 in the subject proceeding, dated the 18th of April, please find attached The Society of Energy Professionals' Final Submissions in the Ontario Power Generation Inc. 2017-2021 Payment Amounts Application, EB-2016-0152.

Two (2) hard copies of this submission have been sent to your attention.

Sincerely,

[Original signed by]

Matthew Kellway
Special Assistant to the President & Manager, Central Functions
The Society of Energy Professionals
kellwaym@thesociety.ca

Copy by email: interested parties

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The Society of Energy Professionals
FINAL SUBMISSIONS

EB-2016-0152 Ontario Power Generation Inc.

2017-2021 Payment Amounts Application

29th May, 2017

As concluded by OEB staff in their submission on their consideration of the CRVA and the X-factor [pp162,163], "it is important to get a plan that is reasonable and realistic and ensures sharing of the plan, overall, between OPG and its shareholder and Ontario electricity consumers, and [OEB staff] is concerned about the possibility of unintended consequences of a subjective and likely arbitrary adjustment". The Society submits that the OEB must take similar considerations into account in taking its decision regarding the setting of hydroelectric rates in the term of this first ever hydroelectric IR period in order eliminate the possibility of unintended consequences of a subjective and likely arbitrary adjustment.

Issue 12.1 Are the effective dates for new payment amounts and riders appropriate?

The Society submits that it agrees with and supports the submissions of both OPG and OEB staff that a January 1, 2017 effective date for payment amounts is reasonable. Specifically, as outlined by OEB staff in their submission [pp180], OPG's application was filed shortly after audited results for 2015 were available, and OPG has met the deadlines established by the OEB in Procedural Order No. 1, issued on August 12, 2016.

ALL OF WHICH IS RESPECTFULLY SUBMITTED ON THIS 29th DAY OF MAY, 2017

Saba Zadeh
Director

Ontario Regulatory Affairs

700 University Avenue, Toronto, Ontario M5G 1X6

Tel: 416-592-2976 Fax: 416-592-8519
saba.zadeh@opg.com

June 19, 2017

VIA RESS AND COURIER

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1 E4

Dear Ms. Walli:

Re: EB-2016-0152 – Ontario Power Generation Inc. 2017-2021 Payment Amounts Application – OPG Reply Argument

Please find attached OPG's Reply Argument for its payment amounts application in EB-2016-0152.

Best Regards,

[Original signed by]

Saba Zadeh

Attach

cc:	Charles Keizer (Torys)	via email
	Crawford Smith (Torys)	via email
	John Beauchamp	via email

EB-2016-0152

OEB Application

for

Payment Amounts for OPG’s Prescribed Facilities

Reply Argument

Ontario Power Generation Inc.

June 19, 2017

submissions in opposition of their proposed off-ramp. OPG submits that the OEB should find OPG's off-ramp proposal to be appropriate on the basis of its written evidence.

13.0 IMPLEMENTATION

13.1 Issue 12.1

Primary: Are the effective dates for new payment amounts and riders appropriate?

OPG has asked for an effective date of January 1, 2017, in respect of the payment amounts associated with the prescribed hydroelectric and nuclear facilities (Ex. A1-2-1, pp.1-2). Moreover, OPG has asked for recovery, by way of rate riders, of the difference between existing payment amounts and the payment amounts approved in this Application from the effective date to the implementation date.

OEB staff, QMA, and SEP support OPG's request.[174] As OEB staff says, "a January 1, 2017 effective date for payment amounts is reasonable. The application was filed shortly after audited results for 2015 were available," and "OPG has met the deadlines established by the OEB in Procedural Order No.1." Where OPG did file updates to its Application, these updates were limited in scope as stated in Ex. N1-1-1, p. 4, to minimize the impact on the processing schedule and to keep the impact statements to a manageable size.

The remaining parties that take a position on this issue oppose OPG's request. SEC, for example, goes so far as to say that staff's position amounts to giving OPG a "free pass" (SEC argument, para. 11.1.8). It argues that the effective date should be the 1st of the month following the final payment amounts order. SEC estimates this date to be 461 days after the Application was filed. SEC and others that adopt its position justify their argument by reference to the OEB's decision in EB-2013-0321 and the time between the filing and effective dates in that case (447 days). Their argument should be rejected.

Filing the Application 461 days in advance of January 1, 2017 would have meant a filing date of approximately mid-October 2015. Realistically, OPG would have had to prepare and compile the Application through the spring and summer of that year. At that time:

[174] See OEB staff argument, p. 180; QMA argument p. 11; SEP argument p. 25.

- financial results for 2015 (audited or otherwise) were not available or known;
- the 2016-2018 Business Plan which underpins the Application had not been prepared or approved;
- the RQE for the Darlington Refurbishment Program and the Business Case for PEO had not been completed by OPG or endorsed by the Province;
- the amended Bruce Lease agreement between OPG and Bruce Power and the amended refurbishment agreement between Bruce Power and the IESO had not been executed; and
- O. Reg. 53/05 had not been amended.

This information, which forms the backbone of the Application and is necessary for the OEB to make a decision as to just and reasonable payment amounts, would not have been included in the initial filing. As a result, OPG would have to have undertaken at least one, if not several, large-scale updates to fundamental elements of the Application. For parties that have expressed that the Application is too complex, this would have made the situation significantly worse, and OPG submits, would have been unhelpful to the OEB and OEB staff.

Parties' reference to the EB-2013-0321 proceeding is also misplaced. There, unfortunately, the case began with an incomplete filing which was only rectified a month before OPG's proposed effective date. As the OEB made clear in its decision, this was a failing on OPG's part and it had opportunities to file a complete application much earlier. This is not that case in this Application. OPG filed a complete, compliant application at the end of May 2016, its first opportunity to do so after all essential information was available.

13.1.1 Effective Date, the RSDA, and Other Deferral and Variance Accounts

Some parties have commented that "if the OEB selects an effective date other than January 1, it should be clear that any revenues that are foregone on account of the effective date should not be recorded in the RSDA" (OEB staff argument, p. 181). SEC in particular has unfairly generalized OPG's response to Undertaking J23.1 on this issue as "OPG claim[ing] that it would use the Rate Smoothing Variance Account ("RSVA") to claw back the entire amount of the deficiency for the period from January 1, 2017 to the effective date ordered by the Board" (SEC argument, para. 11.1.11).

What OPG actually said in Undertaking J23.1 is that if the OEB approves a nuclear revenue requirement effective January 1, 2017 based on this Application but determines a later effective date for the new payment amounts, O. Reg. 53/05 would require the difference between the new revenue requirement and existing payment amounts to be recorded in the RSDA for the period between January 1, 2017 and the effective date of the new payment amounts.[175] OPG's response in Ex. J23.1 made this clear at lines 25-26, where it said "[a]s stated in Tr. Vol. 23, pp.26-27, this scenario assumes that the OEB approves the full year revenue requirement as requested by OPG for 2017-2021" (emphasis added). OPG stands by this position because it reflects the requirements of O. Reg. 53/05.

OPG's position is not a "clawback trick" as SEC has flippantly characterized it (SEC argument, para. 11.17). OPG takes this position because section 5.5 of O. Reg. 53/05 clearly provides that the RSDA will record entries starting with beginning of the deferral period which is defined as beginning January 1st 2017 (O. Reg. 53/05, section 0.1 "definition"), where, per section 5.5(1) such entries are determined as 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. (emphasis added).

The remainder of SEC's claim is easily addressed. Unlike the situation in EB-2013-0321 where large elements of the revenue deficiency were covered by D&V accounts (e.g., the Niagara Tunnel, and Pension and OPEB costs), in this Application none of the largest drivers of the revenue deficiency are subject to variance account treatment (e.g. production and nuclear

[175] To be compliant with O. Reg. 53/05, the specific calculation of the amount recorded in the RSDA for this period would need to consider the fact that Section 5.5(1) of O. Reg. 53/05 references the difference between two revenue requirements rather than a revenue requirement and amounts collected based on actual production, as discussed below.

OM&A expenses) (Ex. A1-3-4, p. 6). SEC is fighting yesterday's battle when it warns that variance accounts may materially reduce the impact of a later implementation date.

13.1.2 A January 1, 2017 Effective Date is Appropriate

There is tension between filing well in advance of a proposed effective date and providing the OEB and parties with the best available information that is reasonably current, upon which to make a decision. OPG respectfully submits that it has struck an appropriate balance in this case, while being mindful and respectful of the OEB's process. An effective date of January 1, 2017 should be approved.

Ontario Energy Board | Commission de l'énergie de l'Ontario

EB-2013-0321

IN THE MATTER OF AN APPLICATION BY

ONTARIO POWER GENERATION INC.

PAYMENT AMOUNTS FOR PRESCRIBED FACILITIES FOR 2014 AND 2015

DECISION WITH REASONS

November 20, 2014

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EB-2013-0321

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

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

BEFORE: Marika Hare
Presiding Member

Christine Long
Member

Allison Duff
Member

DECISION WITH REASONS

NOVEMBER 20, 2014

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Table of Contents

Appendices:

EXECUTIVE SUMMARY

This is the Decision of the Ontario Energy Board (the "Board") regarding an application filed by Ontario Power Generation Inc. ("OPG"). OPG is the largest electricity generator in Ontario. Provincial regulation requires that the Board set the rates that OPG charges for the generation from its nuclear facilities (Pickering and Darlington) and most of its hydroelectric facilities (e.g. Sir Adam Beck I and II on the Niagara River). The rates charged by OPG are referred to as payment amounts and are expressed in dollars per megawatt-hour ($/MWh). These payment amounts are included in the electricity costs which are shown as a line item on the electricity bill from a customer's distributor, and make up about half the total of an average household bill.

Payment amounts for electricity generated from OPG's two nuclear facilities and six of its hydroelectric facilities (on the Niagara, Welland and St. Lawrence Rivers) were last set for the period 2011 and 2012. These amounts remained in place for 2013 as OPG did not file a payment amounts application for 2013. Payment amounts are set by the Board in accordance with provincial regulations which stipulate, among other matters, which facilities are included in the payment amounts. As of July 1, 2014 these facilities include 48 hydroelectric plants that were not previously covered by the regulation. These hydroelectric plants are referred to as the "newly regulated" hydroelectric facilities in this Decision.

If the payment amounts were approved by the Board as proposed by OPG, the bill impact on a typical residential customer would be an increase of $5.31 per month, or a 23.4% increase over current payment amounts. However, this Decision adjusts numerous elements that factor into the calculation of the resulting payment amounts. These include elements such as costs, revenues, taxes and production forecasts. The approximate impact on the payment amounts as a result of this Decision is an increase of 10% over the payment amounts that OPG is currently paid, a significant reduction over the increase requested by OPG. This is an approximation only, as the exact number cannot be determined until OPG reflects all aspects of this Decision that factor into the calculation of the resulting payment amounts.

OPG filed an incomplete application at the end of September 2013. The proceeding leading to this Decision was extremely lengthy, due to the delay in the filing of a complete application, several updates to the evidence from December 2013 to July

2014, and complexities associated with the amount of information for which confidential treatment was sought.

In reaching its findings, the Board was aided by the participation of 20 parties, representing diverse customer interests and policy matters, and Board staff. The Board also took note of 41 letters of comment received from customers and numerous independent consultant reports. In addition, the Auditor General's report[1] was filed in this proceeding and provided context to OPG's human resources issues.

This Decision of the Board addresses issues in the detail required to set the payment amounts for 2014 and 2015. The Decision is organized into the following major sections: introduction, regulated hydroelectric facilities, nuclear facilities, corporate matters, design of payment amounts and implementation of the Decision. Key highlights of this Decision include:

- Reduction in OPG's proposed Operations, Maintenance and Administration budget in both the nuclear and hydroelectric sides of the business mainly due to excessive compensation. The reductions total $100 M per year.
- Approval of a $1,364.6M addition to rate base due to the completion and in-service addition of the Niagara Tunnel, a reduction of $88M from what OPG had requested to be included.
- Approval of the in-service additions associated with the Darlington Refurbishment project for 2014 and 2015.
- Denial of the request for approval of commercial and contracting strategies with respect to the Darlington Refurbishment project.
- Rejection of the accrual method of accounting for determining pension and other post-employment benefit costs for ratemaking in 2014 and 2015.
- Adjustment of the debt:equity ratio from 53:47 to 55:45.
- Direction to OPG to undertake independent and comprehensive benchmarking studies for the hydroelectric business and for corporate support costs, and to undertake a comprehensive compensation study.
- Effective date for the commencement of these new payment amounts will be November 1, 2014.

[1] Annual Report of the Auditor General of Ontario, Chapter 3.05 OPG Human Resources, December 10, 2013 (Exh KT2.4)

1 INTRODUCTION

Ontario Power Generation Inc. filed an application with the Ontario Energy Board on September 27, 2013. The initial application was deemed by the Board to be incomplete, and the complete application was not filed until December 5, 2013. The application was filed under section 78.1 of the *Ontario Energy Board Act, 1998*, S.O 1998, c. 15 (Schedule B) (the "Act"), seeking approval for payment amounts for OPG's previously regulated hydroelectric facilities and nuclear facilities for the test period January 1, 2014 through December 31, 2015, to be effective January 1, 2014. The application also seeks approval for payment amounts for newly regulated hydroelectric facilities to be effective July 1, 2014. The Board assigned the application file number EB-2013-0321.

OPG requested, and the Board issued, an order declaring the current payment amounts interim for the previously regulated hydroelectric facilities and nuclear facilities as of January 1, 2014 and for the newly regulated hydroelectric facilities as of July 1, 2014, pending the Board's final decision.

1.1 Legislative Requirements

Section 78.1(1) of the Act establishes the Board's authority to set the payment amounts for the prescribed generation facilities. Section 78.1 can be found at Appendix A of this Decision. 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 Board 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 Appendix B.

On November 27, 2013, O. Reg. 53/05 was amended to require regulation by the Board of 48 additional hydroelectric stations.

1.2 The Prescribed 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 six previously regulated hydroelectric generating stations and two nuclear generating stations. As amended in November 2013 and set out in section 2 and the schedule of O. Reg. 53/05, the newly regulated hydroelectric facilities are comprised of 48 stations. OPG operates these stations in 4 plant groups, as shown in the table below. The regulated facilities produce more than half of the electricity consumed in Ontario.

Table 1: Prescribed Generation Facilities

Previously Regulated Hydroelectric		Newly Regulated 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 Board 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.

OPG has entered into a Memorandum of Agreement with its shareholder. This Memorandum sets out the shared expectations of OPG and its shareholder regarding OPG's mandate, governance, performance and communications. Included in its provisions related to the nuclear mandate are expectations related to continuous improvement, benchmarking, and improved operations. The Memorandum is reproduced at Appendix C.

1.3 Previous Proceedings

The current application is OPG's third cost of service application. The previous proceedings were assigned file numbers EB-2007-0905 and EB-2010-0008.[2]

In 2012, OPG filed an application, EB-2012-0002, seeking approval to adopt Generally Accepted Accounting Principles of the United States ("USGAAP") for regulatory accounting purposes and to clear 2012 year-end deferral and variance account balances for all accounts except for four. Parties to the proceeding achieved settlement and the Board accepted the settlement proposal. The EB-2012-0002 decision established payment amount riders for 2013 and 2014 to clear the 2012 account balances. In this proceeding OPG proposes disposition of the four accounts not previously cleared in EB-2012-0002.

1.4 The Application

The application filed on September 27, 2013 was underpinned by OPG's 2013-2015 business plan. The application, as filed, was deemed by the Board to be incomplete and OPG filed additional evidence on December 5, 2013 to meet the Board's filing

[2] The EB-2010-0008 decision was appealed by OPG. The appeal was dismissed at the Divisional Court. OPG was successful before the Ontario Court of Appeal. The Court of Appeal's decision has now been appealed to the Supreme Court of Canada, and that appeal is expected to be heard in December 2014.

requirements. If approved, the application would result in an increase of $5.36 on the monthly total bill for a typical residential customer consuming 800 kWh per month. This information was published in the Notice of Application in 88 newspapers throughout the province.

OPG filed an impact statement on December 6, 2013 (Exhibit N1) that updated the application to reflect material changes in costs and production forecasts for the 2014-2015 period which were included in OPG’s 2014-2016 business plan. As the bill impact resulting from the Exhibit N1 update would result in an increase of $5.94 on the monthly total bill, the Board determined that further notice was required.

A second impact statement was filed on May 16, 2014 (Exhibit N2) to update the application to reflect material changes in costs and production forecasts that had arisen since the first impact statement was filed in December 2013. The bill impact of the subsequent Exhibit N2 update was proposed to be an increase of $5.31 per month. Based on the Exhibit N2 update, OPG is seeking an increase of 23.4% on payment amounts.

The proposed revenue requirement, as updated on May 16, 2014, is summarized in the following table.

Table 2: Proposed Revenue Requirement

$million	Previously Regulated Hydroelectric		Newly Regulated Hydroelectric		Nuclear		
	2014	2015	2014 [1]	2015	2014	2015	TOTAL
Expenses OM&A[2]	145.1	140.0	117.5	237.3	2,401.4	2,419.8	5,461.1
Gross Revenue Charge/Nuclear Fuel	267.2	280.8	37.8	77.5	266.5	260.5	1,190.3
Depreciation	82.1	81.9	31.1	63.1	273.7	288.5	820.4
Property Tax	0.3	0.3	0.1	0.1	15.9	16.4	33.1
Income Tax	49.7	64.2	15.0	42.7	108.3	16.8	296.7
Cost of Capital Short-term Debt	3.6	4.6	0.9	2.3	1.6	2.1	15.1
Long-term Debt	127.0	126.2	31.1	62.7	57.4	58.3	462.7
Return on Equity	225.6	227.7	55.3	113.2	101.9	105.3	829.0
Adjustment for lesser of UNL or ARC[3]					74.6	70.3	144.9
Other Revenue	(34.0)	(34.6)	(11.4)	(23.1)	(33.2)	(30.5)	(166.8)
Bruce Net Revenue					(39.7)	(40.6)	(80.3)
Revenue Requirement	866.6	891.1	277.3	575.8	3,228.4	3,166.9	9,006.1
Deferral and Variance Accounts		70.6				62.2	132.8
Note 1: The newly regulated hydroelectric revenue requirement reflects July 1, 2014							
Note 2: OM&A - Operations, Maintenance and Administration Costs							
Note 3: UNL - unfunded nuclear liability, ARC - asset retirement cost							

To achieve the revenue requirement and disposition of balances in the four deferral and variance accounts, OPG requested the payment amounts and riders shown in the following table, which also provides the current payment amounts and riders.

Table 3: Payment Amounts and Riders

$/MWh	Previously Regulated Hydroelectric	Newly Regulated Hydroelectric	Nuclear
Current			
Payment Amount	35.78		51.52
Rider (2013)[1]	3.04		6.27
Rider (2014)[1]	2.02		4.18
Proposed			
Payment Amount	42.75	47.57	67.60
Rider (2015)	3.36		1.35

Note 1: Payment Amount Riders established by EB-2012-0002

A summary of the approvals that OPG is seeking in the current application is found at Appendix D.

1.5 The Proceeding

Details of the procedural aspects of the proceeding are provided at Appendix E.

In the EB-2010-0008 decision, the Board stated that it “will explore with OPG and stakeholders how best to identify issues in the next proceeding to ensure that the highest priority issues are identified early.” The Board also expressed concern that “an inordinate focus on lower priority issues diminishes the time and resources available to pursue the more substantive, higher priority issues.” As a result, the Board established a process for categorizing primary and secondary issues in this cost of service proceeding and made provision for a settlement process for certain issues. Any unsettled primary issues would proceed to oral hearing and any unsettled secondary issues would proceed to written hearing.

The Board convened a settlement conference between OPG and the parties on May 21 to 26, 2014. No settlement was achieved. The Board established the final prioritized issues list for the proceeding in June, 2014. That issues list is found at Appendix F.

The Board received 41 letters of comment in response to the Notices of Application. The Board has reviewed each of these letters. The letters raise a variety of issues, many of which are dealt with in this Decision. Many of the letters of comment expressed concern about the request to increase payment amounts and the difficulty customers faced in paying current electricity bills without any additional increase. Although the Board will not address each letter specifically, the comments have been taken into account in the Board's deliberations.

Two parties applied for, and were granted, observer status. Twenty parties applied for and were granted intervenor status. The submissions of the following parties are referred to in this Decision: 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, Green Energy Coalition ("GEC"), Independent Electricity System Operator ("IESO"), Lake Ontario Waterkeeper ("Waterkeeper), London Property Management Association ("LPMA"), Power Workers' Union ("PWU"), School Energy Coalition ("SEC"), Society of Energy Professionals ("Society"), Sustainability-Journal and Vulnerable Energy Consumers Coalition ("VECC").

During the proceeding, confidential treatment was sought for a large number of documents.

This Decision addresses issues in the detail required to set the payment amounts for 2014 and 2015. The Decision is organized into the following major sections: the regulated hydroelectric facilities, nuclear facilities, corporate matters, design of payment amounts and implementation of the Decision.

2 REGULATED HYDROELECTRIC FACILITIES

2.1 Hydroelectric Production Forecast

(Issues 5.1 and 5.2)

At the highest level, OPG's payment amounts result from a simple equation: OPG's reasonably incurred costs divided by the number of megawatt-hours it is expected to produce (i.e. the production forecast). The production forecast put forward by OPG, therefore, is a major input in the calculation of final payment amounts. OPG proposed for the Board's approval a production forecast of 32.5 TWh[3] for 2014 and 33.5 TWh for 2015.

OPG's historical hydroelectric production and production forecast for 2014 and 2015 are summarized in the following table. The production includes the Niagara Tunnel Project which went into service in March 2013.

Table 4: Hydroelectric Production Forecast

TWh	2010 Actual	2011 Approved	2011 Actual	2012 Approved	2012 Actual	2013 Budget	2013 Actual	2014 Plan	2015 Plan
Niagara	12.4	12.9	12.6	12.9	11.9	12.2	12.4	12.8	13.5
Saunders	6.5	7.0	6.9	7.0	6.5	6.2	6.5	6.3	6.7
Sub-Total	**18.9**	**19.9**	**19.5**	**19.9**	**18.4**	**18.4**	**18.9**	**19.1**	**20.2**
Newly Regulated	10.0		11.5		10.9	12.4	12.5	12.4	12.5
Total	**28.9**		**31.0**		**29.3**	**30.8**	**31.4**	**31.5**	**32.7**
Exhibit N1 Update - Previously Regulated only, no change for Newly Regulated								**32.5**	**33.5**
Source: Exh E1-1-2, Exh L-1-Staff-2, Exh N1-1-1									

OPG uses computer models to predict water flow and production forecast for the previously regulated hydroelectric facilities and the larger of the newly regulated hydroelectric facilities. The production forecast for the 27 smaller newly regulated hydroelectric facilities is based on historical production.

The hydroelectric water conditions variance account captures the impact of the difference between forecast and actual water conditions for the previously regulated hydroelectric facilities. OPG proposes that the variance account also apply to the larger of the newly regulated hydroelectric facilities.

[3] One terawatt-hour = 1,000,000 megawatt-hours

OPG's production forecast did not include an adjustment for surplus baseload generation. This condition occurs when electricity production from baseload facilities (such as nuclear and hydroelectric) exceeds Ontario demand. When OPG is unable to store water in a surplus baseload generation situation, the financial impact of the foregone revenue is recorded in the surplus baseload generation variance account.

CME observed that the balances in the variance account are large and submitted that the Board should embed some level of surplus baseload generation into the payment amounts by adjusting OPG's production forecast. In reply, OPG submitted it did not disagree with CME's proposal, but chose to maintain the Board-approved approach in EB-2010-0008, utilizing a variance account rather than including a forecast production adjustment.

Board staff observed that actual surplus baseload generation in 2011 and 2012 was significantly lower than forecast for those 2 years. Board staff and several other parties submitted that the production forecast, without surplus baseload generation adjustment, was appropriate.

Board Findings

The Board accepts the hydroelectric production forecast as filed. The forecast methodology was based on the methodology used in EB-2010-0008 for the previously regulated hydroelectric production forecast. The same production forecast methodology was applied to the larger of the newly regulated hydroelectric assets. The hydroelectric production forecast of 66.0 TWh (32.5 TWh for 2014 and 33.5 TWh for 2015) is reasonable.

OPG provided estimates of surplus baseload generation in 2014 and 2015 for information purposes only, not for the purpose of adjusting its hydroelectric production forecast and revenue requirement calculation. As a result, the Board does not find it necessary to comment on the 2014 and 2015 estimates provided, as the actual revenue implications will be captured in the surplus baseload generation variance account.

The Board will not implement CME's proposal to include a forecast production adjustment given the uncertainties in any surplus baseload generation forecast for the previously regulated or the newly regulated hydroelectric facilities.

2.1.1 Hydroelectric Incentive Mechanism (Issues 5.3 and 5.4)

OPG has the ability to store water at its pump generating station, and at some of its other hydroelectric facilities. Water can be "held back" during periods of low demand (and low market prices), and then released during periods of higher demand (and consequently higher market prices). Shifting production of relatively low cost hydroelectric power from periods of low demand to periods of high demand will generally benefit all consumers by lowering the market price during high demand periods.

OPG could be paid the same amount for production no matter what the market price is, however, OPG would have no built in monetary incentive to shift its regulated hydroelectric generation from periods of low demand to periods of high demand. For this reason, starting with the incentive in O. Reg. 53/05, OPG has been provided with an incentive to shift its hydroelectric production from times of low demand to times of high demand.

In OPG's last payments proceeding (EB-2010-0008) the Board found that a revised hydroelectric incentive mechanism for production from OPG's regulated hydroelectric assets was appropriate. The approved hydroelectric incentive mechanism was based on sharing 50% of the hydroelectric incentive mechanism revenues through revenue requirement adjustments, retention by OPG of an equal amount and sharing of any additional net revenues.

The EB-2010-0008 decision also directed OPG to undertake an analysis of the interaction between the hydroelectric incentive mechanism and surplus baseload generation. OPG's analysis indicated that as a result of surplus baseload generation reducing the monthly average hourly production threshold for the hydroelectric incentive mechanism, there was an unintended benefit to OPG. The 2011-2013 unintended benefit to OPG has been determined to be $6.8M.[4]

In the current proceeding, OPG has proposed an enhanced hydroelectric incentive mechanism that is based on a forecast of consumer benefits and which it considered to be administratively simpler. The mechanism would apply to both previously and newly regulated hydroelectric facilities. OPG estimates the consumer benefits resulting from

[4] Undertaking J4.7

the enhanced hydroelectric incentive mechanism to be $36M in each of 2014 and 2015 and proposes X-factor adjustments to the hydroelectric incentive mechanism and surplus baseload generation monthly calculations such that the benefits are shared and the unintended benefit to OPG is corrected. OPG's proposal also included elimination of the revenue requirement adjustment and no further additions to the hydroelectric incentive mechanism variance account.

OPG indicated that it would not change how the previously and newly regulated hydroelectric facilities are operated under the enhanced hydroelectric incentive mechanism. Under that premise, the IESO submitted that the enhanced hydroelectric incentive mechanism is acceptable from a market efficiency perspective.

Board staff submitted that the enhanced hydroelectric incentive mechanism is based on OPG's forecast of benefits and could generate results that are one-sidedly beneficial to OPG. However, OPG argued that actual benefits could be lower, so the proposal is symmetric.

Board staff submitted that the current hydroelectric incentive mechanism should be retained with revenue requirement adjustments of $22M in 2014 and $37M in 2015 to reflect the addition of the newly regulated hydroelectric facilities. While the current mechanism provides for 50:50 revenue sharing, Board staff submitted that the Board could consider a graduated sharing such that more was returned to ratepayers at higher revenue levels. Board staff submitted that an after-the-fact adjustment to the monthly average hourly production threshold that corrects for surplus baseload generation impacts should be processed. The staff submission was supported by most parties.

OPG stated that the Board staff submission is inferior to the enhanced hydroelectric incentive mechanism proposed by OPG. However, if the Board adopts the approach put forward by Board staff, the hydroelectric incentive mechanism variance account should be symmetrical, protecting both ratepayers and OPG. OPG also argued that there is no need for a graduated sharing mechanism as it would have the effect of reducing the amount of time shifting that OPG performs.

CME and VECC submitted that the December 31, 2013 balance in the surplus baseload generation account should be adjusted by the $6.8M unintended benefit. This matter is also noted in the deferral and variance account section of this Decision.

Board Findings

The Board finds that the current incentive mechanism has encouraged appropriate use of the regulated hydroelectric facilities to supply energy in response to market prices. OPG's witnesses testified that they are incented to move production from periods of low value to periods of high value, based on market signals.

The Board does not approve OPG's proposed new enhanced hydroelectric incentive mechanism. OPG failed to demonstrate to the Board that the enhanced mechanism was superior to the current mechanism in terms of incentives for OPG or benefits to ratepayers.

OPG's enhanced hydroelectric incentive mechanism proposal is predicated on forecasts of consumer cost changes and cost reductions, resulting from its customer benefits analysis. The Board finds that OPG's enhanced hydroelectric incentive mechanism proposal fundamentally shifts from a revenue sharing concept to an estimate of forecast consumer benefits.

Further, the enhanced hydroelectric incentive mechanism is dependent upon OPG's forecasts and estimates, as OPG proposes to close the variance account established by the Board in the last proceeding to any further additions. The purpose of the variance account was to enable the sharing of actual revenues above the hydroelectric incentive mechanism threshold, between OPG and ratepayers.

Board staff recommended the Board maintain the current hydroelectric incentive mechanism and direct OPG to change its monthly average hourly production threshold calculation to address any unintended benefit in 2014 and 2015. OPG has the information required to make the calculation as it provided the unintended benefit from March 2011 to December 2013. The Board sees merit in Board staff's proposal for the following reasons:

- It provides ratepayers with a revenue sharing potential beyond the forecast in the revenue requirement adjustment.
- It provides OPG with the incentive to maximize actual revenues beyond the forecast, in responding to market prices.
- It is very similar to the existing incentive, yet provides a simple way to correct for the unintended surplus baseload generation benefit.

The Board finds the structure of the current variance account appropriate as a mechanism for sharing actual revenues beyond the threshold implicit in the revenue requirement adjustment. The Board will not change the structure of the variance account and will maintain its asymmetrical structure for 2014 and 2015. The Board reiterates its findings in the EB 2010-0008 decision that this incentive is a premium paid by ratepayers to OPG so OPG will operate in a way which is of greater benefit to ratepayers. With the addition of the newly prescribed assets to the hydroelectric generating business, the forecast of benefits arising from the hydroelectric incentive mechanism has increased significantly. For this reason, the Board will change the threshold levels for sharing given OPG's forecast of benefits. A second change from the previous mechanism is to utilize 50% of the forecast in the revenue requirement.

The Board finds no compelling reason to change the revenue sharing ratio from the current 50:50 split. Alternative proposals were made in submissions only, and therefore not explored in the hearing.

As a result, the Board finds the revenue requirement will be adjusted by $39M in 2014 and $48M in 2015, which is 50% of the forecast hydroelectric incentive mechanism revenues of $78M and $96M for the previously regulated and newly regulated hydroelectric assets.[5] The next $39M of hydroelectric incentive mechanism revenues in 2014 and $48M in 2015 will be retained by OPG. Therefore, the $78M and $96M will be the new thresholds, with any additional revenues beyond those amounts shared equally between OPG and ratepayers enabled by the variance account.

OPG shall allocate the revenue requirement adjustment between the previously regulated and newly regulated hydroelectric assets as appropriate.

2.1.2 Energy Storage
(Issue 5.1(a))

Sustainability-Journal submitted that the use of energy storage to meet peak demand instead of peak generation systems would reduce cost and emissions. Examples of energy storage include the Enwave Toronto District Heating system and ground source systems. Sustainability-Journal submitted that, while the OPA and IESO have plans to enter into contracts to build storage systems, the consideration of long term storage

[5] Exh L-5.4-SEC-73

options has been limited. Sustainability-Journal argued that OPG and other organizations regulated by the Board, should be required to produce public reports that consider energy storage options.

OPG replied that it does not have the type of energy storage facilities described by Sustainability-Journal and has no plans to build such facilities. Its view was that it is not necessary for OPG to produce reports on the matter.

Board Findings

The Board will not direct OPG to undertake a study of energy storage facilities and opportunities as described by Sustainability-Journal. OPG has indicated it does not intend to pursue such projects, and therefore, the further study of energy storage would not be a wise use of ratepayer money. The government's Long-Term Energy Plan discusses energy storage technologies. The Board will not prescribe a role for OPG in developing those technologies; however, the Board encourages OPG to keep abreast of new technologies in energy storage.

2.2 Hydroelectric OM&A and Benchmarking
(Issues 6.1 and 6.2)

OPG seeks approval of operating costs of $494.7M in 2014 and $503M in 2015 for the previously regulated hydroelectric facilities. OPG seeks approval of operating costs of $372.9M in 2014 and $378M in 2015 for the newly regulated hydroelectric facilities.

Hydroelectric facility operating costs include OM&A costs, an allocation of corporate support and centrally held OM&A, gross revenue charges (taxes and water rental component governed by legislation), and depreciation and taxes. This section of the Decision addresses hydroelectric OM&A and benchmarking. The other components of hydroelectric operating costs are discussed later in this Decision.

OPG's historical and forecast OM&A for the previously regulated hydroelectric facilities are summarized below.

Table 5: Previously Regulated Hydroelectric OM&A

$million	2010 Plan	2010 Actual	2011 Approved	2011 Actual	2012 Approved	2012 Actual	2013 Budget	2013 Actual	2014 Plan	2015 Plan
Base	61.8	59.4	68.7	50.1	62.1	60.2	71.9	61.6	74.6	68.6
Project	5.3	5.4	9.7	6.6	10	13.6	13	14.7	13.5	17.9
SubTotal Operations	67.1	64.8	78.4	56.7	72.1	73.8	84.9	76.3	88.1	86.5
Corporate Costs	25.1	22.4	24.8	22.0	26.3	24.5	29.7	26.1	29.8	26.9
Centrally Held Costs	20.3	19.6	22.9	15.9	25.5	19.6	25.1	20.7	26.1	26.0
Asset Service Fee	2.0	2.1	2.1	1.6	2.0	1.8	1.7	1.6	1.5	1.7
SubTotal Other	47.4	44.1	49.8	39.5	53.8	45.9	56.5	48.4	57.4	54.6
Total OM&A	**114.5**	**108.9**	**128.2**	**96.2**	**125.9**	**119.7**	**141.4**	**124.7**	**145.5**	**141.1**
Exhibit N1 Update									**149.2**	**144.2**
Exhibit N2 Update									**145.1**	**140.0**

Sources: Exh F1-1-1 Table 1, Exh L-6.1-CCC-17, Exh L-1-Staff-2 Table 15, Exh N2-1-1 Attachment 5

OPG's historical and forecast OM&A for the newly regulated hydroelectric facilities are summarized below.

Table 6: Newly Regulated Hydroelectric OM&A

$million	2010 Plan	2010 Actual	2011 Plan	2011 Actual	2012 Plan	2012 Actual	2013 Budget	2013 Actual	2014 Plan	2015 Plan
Base	93.7	100.0	103.7	106.0	108.8	102.9	113.2	103.5	113.4	113.7
Project	37.1	39.8	27.3	21.6	20.6	20.3	16.0	23.1	24.5	32.1
SubTotal Operations	130.8	139.8	131.0	127.6	129.4	123.2	129.2	126.6	137.9	145.8
Corporate Costs	N/A	31.4	N/A	32.3	N/A	36.6	38.8	35.2	42.1	39.6
Centrally Held Costs	N/A	19.0	N/A	25.1	N/A	33.1	47.2	31.8	49.6	48.7
Asset Service Fee	N/A	3.6	N/A	3.4	N/A	3.3	3.1	3.0	2.9	3.0
SubTotal Other		54.0		60.8		73.0	89.1	70.0	94.6	91.3
Total OM&A		**193.8**		**188.4**		**196.2**	**218.3**	**196.6**	**232.5**	**237.1**
Exhibit N1 Update									**239.3**	**242.6**
Exhibit N2 Update									**234.9**	**237.3**

Sources: Exh F1-1-1 Table 2, Exh L-6.1-CCC-18, Exh L-1-Staff-2 Table 16, Exh N2-1-1 Attachment 5

There were several submissions on base and project OM&A variances. Parties observed a trend of historical under-spending versus forecast but no operational repercussions as a result of the under-spending. Board staff submitted that base and project OM&A costs should be reduced by $8.2M for each test year on the basis of OPG's updated 2014 year end forecast. SEC and LPMA proposed reductions on the basis of their analysis of historical variances.

As OPG only provided an updated 2014 year end forecast for base and project OM&A, Board staff also proposed reductions of an additional $27.2M, allocated to other OM&A

costs for each test year, on the basis of over-forecasting expenses. The submissions of other parties on these costs are noted in the corporate support cost section of this Decision.

As the application is based on a forward test period, OPG submitted that consideration should be given to forecast events in the business plan for 2014 and 2015. OPG submitted that the Board staff reference to the updated 2014 year end forecast for base and project OM&A is cherry picking and that the historical under-spending means that work was reprioritized to deal with unfilled vacancies and that OPG overcame these issues with only minor impacts to the business.

Benchmarking

OPG filed reliability, cost and safety performance benchmarking for the hydroelectric business with its application. Board staff observed that OPG purchases raw databases and submitted that the benchmarking provided in the application is not done independently. OPG's witnesses stated that they have not commissioned any independent hydroelectric benchmarking and they do not have plans to do any.[6] OPG indicated that EUCG and Navigant are third parties who act independently to define, collect and verify the raw data reported by OPG, although these third parties do not produce any reports.

OPG confirmed that only base OM&A costs are benchmarked. SEC submitted the benchmarking results should be of little comfort to the Board as significant costs have been excluded from the analysis. OPG replied that some costs are excluded as the North American hydroelectric utilities that provide the data want the benchmarking data framed without corporate costs.

The Society argued that the Board does not possess the necessary expertise to make any prudent judgment on hydroelectric OM&A. In the Society's view, benchmarking has limited practical value as there are no comparable organizations with regard to scale, diversity and complexity of OPG hydroelectric operations.

Both Board staff and SEC submitted that the Board should direct OPG to conduct a fully independent and fully allocated OM&A benchmarking exercise so that there is an appropriate structure for the hydroelectric incentive regulation framework.

[6] Tr Vol 4 page 3

Board Findings

OPG has historically over-forecast hydroelectric base and project OM&A. The variance analysis of the base and project OM&A for the historical period 2010 to 2013 clearly indicates that actual spending has been consistently less than OPG had forecast. While OPG argues that the approved OM&A should be based on test period events and the business plan underpinning the application, OPG's forecasting methodology in the current proceeding is similar to that described in previous proceedings. In these prior periods, OPG has managed its hydroelectric operations with a lower than forecast base and project OM&A envelope, with only one year being a minor exception. OPG has confirmed that this trend of under-spending relative to forecast is likely to materialize in 2014 as well.[7] The pre-filed evidence and the testimony of OPG's witnesses confirm that the hydroelectric facilities have been operated safely, reliably and meet environmental standards.

When using a forward test year methodology, historical actuals are informative. In this case, the Board is influenced by OPG's consistent historic under spending but is still mindful of OPG's submissions with respect to the need for its proposed OM&A levels for the 2014 and 2015 period. In considering these factors, the Board finds that a base and project OM&A reduction of 4.2% for the regulated hydroelectric assets is appropriate. The reduction would be $9.5M in 2014 and $9.8M in 2015. As the majority of hydroelectric OM&A expense is related to compensation, this reduction to the hydroelectric OM&A budget for each of the two years will be subsumed into the disallowances for compensation discussed later in this Decision.

The Board finds the hydroelectric benchmarking to be inadequate. The analysis of externally provided OM&A, reliability and safety databases and the reporting is done by OPG, not an independent third party. Further, in the two previous cost of service applications and the current application, OPG has provided OM&A benchmarking information that only considers base OM&A which is only 50% of total OM&A expenses. The Board observes that OPG's nuclear business benchmarking is further advanced than its hydroelectric business benchmarking. The Board notes that OPG responded to Board direction from EB-2007-0905 regarding the benchmarking of the nuclear business. In 2009, ScottMadden Inc., assisted by OPG, identified key performance metrics for benchmarking and identified the peer groups for comparison. The nuclear cost benchmarking includes the allocation for corporate costs. OPG has adopted the

[7] Undertaking J3.13

ScottMadden methodology and format in full for its annual nuclear benchmarking reporting.

The Board orders OPG to have a comparable fully independent benchmarking study undertaken of the hydroelectric operations as soon as possible. The results of this study will be important in developing the incentive regulation methodology for OPG. Data used in the study should be as recent as possible (i.e. not older than 2013), without creating delays in the completion and dissemination of the study.

With respect to the Society's view that little weight should be placed on any benchmarking, the Board reminds the Society that the Act and O. Reg. 53/05 provide the Board with the authority to set payment amounts for OPG's regulated facilities. In addition the Memorandum of Agreement between OPG and the Shareholder requires that OPG's regulated assets be subject to public review and assessment by the Board. The Memorandum of Agreement also requires OPG to establish operating and financial results and measures that will be benchmarked against the performance of the top quartile of electricity generating companies in North America.

2.3 Hydroelectric Capital Expenditure and Rate Base

(Issues 2.1, 4.1, 4.2 and 4.3)

OPG seeks Board review of the capital expenditures proposed for 2014 and 2015. These capital expenditures have no impact on the payment amounts for 2014 and 2015 unless the projects are completed and go into service during this period. Board acceptance of the budget does however provide guidance to OPG with respect to the reasonableness of the budget.

OPG's historical and forecast capital expenditures for the previously regulated and newly regulated hydroelectric facilities are summarized below.

Table 7: Hydroelectric Capital Expenditures (excluding Niagara Tunnel)

$millions	2010 Budget	2010 Actual	2011 Approved	2011 Actual	2012 Approved	2012 Actual	2013 Budget	2013 Actual	2014 Plan	2015 Plan
Niagara Plant Group	36.2	28.5	30.7	27.2	30.9	27.1	28.8	20.9	24.8	34.3
Saunders GS	17.3	11.8	9.2	8.1	5.9	2.7	5.0	5.8	9.7	3.9
Newly Regulated *	80.2	68.6	76.7	61.4	91.4	80.1	71.4	60.5	91.0	100.0
Total	**133.7**	**108.9**	**116.6**	**96.7**	**128.2**	**109.9**	**105.2**	**87.2**	**125.5**	**138.2**

Source: Exh D1-1-1 table 2 and Exh L-1-Staff-2 Attachment 1 Table 8

* Note: Amounts for Newly Regulated shown under the Board Approved columns are OPG Budget amounts.

Board staff submitted that a $38M reduction to test period capital was appropriate on the basis of the regulatory delays and economic considerations for the Ranney Falls project. Board staff noted that this reduction would not impact rate base since the planned in-service date is after the test period. OPG replied that there is nothing to suggest that regulatory approvals will not be forthcoming for the Ranney Falls project.

To assess whether test period capital expenditure was reasonable, AMPCO analyzed historical expenditures and determined that for the period 2010 to 2013, OPG spent 81% of the previously regulated hydroelectric facilities budget and 85% of the newly regulated hydroelectric facilities budget. On this basis, AMPCO proposed that reductions to the proposed hydroelectric capital expenditures in the test period in the amount of $43.4M were appropriate. OPG argued that applying historical variances to the test period ignores the evidence filed in support of capital spending in the test period.

OPG is also seeking approval of regulated hydroelectric in-service additions to rate base of $119.9M, $86.1M and $151.6M for 2013, 2014 and 2015, respectively. OPG's historical and proposed rate base for the test period is set out in the following table.

Table 8: Hydroelectric Rate Base

$millions	2010 Budget	2010 Actual	2011 Approved	2011 Actual	2012 Approved	2012 Actual	2013 Budget	2013 Actual	2014 Plan	2015 Plan
Niagara Plant Group excluding NTP	2,489.7	2,452.5	2,482.5	2,437.1	2,474.3	2,422.0	2,405.0	2,404.6	2,391.4	2,378.1
Niagara Tunnel	-	18.3	-	18.1	-	17.8	1,143.6	1,140.4	1,473.6	1,457.7
Saunders GS	1,301.7	1,300.1	1,298.8	1,294.4	1,291.0	1,281.7	1,260.5	1,261.3	1,240.5	1,226.4
NPG Cash Working Capital	23.6	26.4	21.5	21.5	21.5	21.7	21.7	21.7	21.7	21.7
NGP Materials & Supplies	0.7	0.7	0.6	0.8	0.6	0.8	0.7	0.5	0.7	0.7
Newly Regulated *							2,507.0	2,518.4	2,502.6	2,519.2
Newly Reg. Cash Working Capital *							0.7	8.3	8.3	8.3
Newly Reg. Materials & Supplies *							8.3	0.6	0.7	0.7
Total	**3,815.7**	**3,798.0**	**3,803.4**	**3,771.9**	**3,787.4**	**3,744.0**	**7,347.5**	**7,355.8**	**7,639.5**	**7,612.8**

Source: Exh B1-1-1 Table 1 and Exh B2-2-1 Table 1 and Exh L-1-Staff-2 Attachment 1 Table 2
* Note: Amounts for Newly Regulated shown for 2013 are for illustrative purposes.

Based on Board staff's analysis of historical in-service additions for projects greater than $5M, staff observed the forecast additions were generally overstated in the period 2010 to 2013 and proposed a $13M per year reduction for the test period.

SEC reviewed in-service additions for the previously regulated hydroelectric facilities and determined that in aggregate 72.8% of forecast was placed in-service. The following table was filed in the SEC submission.

Table 9

In-Service Capital Additions (excluding NTP) ($M)					
	2010	**2011**	**2012**	**2013**	**Average**
Previously Regulated Plan	60.9	42.9	51.5	44.3	49.9
Previously Regulated Actual	20.0	63.5	15.5	46.4	36.4
Variance (%)	***32.8%***	***148.0%***	***30.1%***	***104.7%***	*72.8%*
Source: D1/1/2/Table 5. L/1.0/Sch 1 Staff-002/Attach 1/Table 2 (2013 Actuals).					

On the basis of SEC's analysis, LPMA proposed that the Board approve 72.8% of the proposed rate base additions for the test period. SEC's analysis of historical capital expenditure for both the previously and newly regulated hydroelectric facilities indicated that 83.3% of plan went into service. SEC proposed that the Board approve 83.3% of the proposed rate base additions for the test period.

Project delays can contribute to in-service addition variances; however, OPG pointed out that there is a cyclical pattern to the variances for the previously regulated hydroelectric facilities. OPG stated that the 2013 variance is minor and an indication of improved forecasting. Further, the major drivers of variances are projects subject to section 6(2)4 of O. Reg. 53/05 which provides for the recording of variances between actual and forecast costs, and are addressed by the capacity refurbishment variance account.

Board Findings

The Board finds that the hydroelectric capital budget for projects coming into service during the test period is reasonable. The projects are supported by business cases approved by the appropriate level of authority within OPG. The Board is providing no explicit approval in this Decision for the capital budget associated with multi-year hydroelectric projects which do not come into service during the test period. As a result, the Board will not reduce OPG's capital budget based on historic budgets exceeding actual expenditures as proposed by certain intervenors and Board staff. The Board is satisfied with OPG's evidence regarding the delays in prior projects to explain historical under spending.

Regarding OPG's proposed in-service capital additions, the evidence indicates no clear pattern of historical variances which can be used to predict actual rate base additions for 2014 and 2015. OPG failed to meet its in-service capital addition budget (or approved level) for its previously regulated hydroelectric facilities in 2010 and 2012, however the budget was exceeded in 2011 and 2013. In the case of additions being lower than budgeted, OPG's witnesses testified that issues arose on specific projects that led to in-service date delays beyond the year in which they were proposed to be in-service. The Board notes that in years in which capital additions exceeded the budget, the amount of overage was much less than the years when the capital additions were below the budgeted level. Over the four year period (2010 to 2013) SEC put forward that the average capital additions were only about 73% of the planned in-service additions.

The Board finds that some level of reduction to the in-service capital additions is required. OPG has not satisfied the Board that it will meet its in-service capital addition budget for 2014 and 2015. Rather than the $13M reduction per year suggested by Board staff, the 17% reduction suggested by SEC or the 27% reduction proposed by LPMA (the latter both based on the four year average additions variance), the Board finds it appropriate to reduce the capital in-service additions by 10% in 2014 and 2015. This amount represents a relatively minor reduction but reflects the fact that the Board is not satisfied by the evidence provided that there will not be in-service delays in 2014 and 2015. The capital additions approved by the Board are therefore $119.9 M in 2013 (actuals), $77.5M in 2014 and $136.4M in 2015.

2.4 Niagara Tunnel Project

(Issues 4.4 and 4.5)

The Niagara Tunnel Project is a 10.2 km long tunnel constructed by OPG with a diameter of 12.7 metres which runs under the City of Niagara Falls. Its purpose is to increase the flow of water to the Niagara plant group, and thereby increase generation by 1.6 TWh annually. After several years of construction, the asset was placed in service in March 2013 at a cost about 50% greater than originally budgeted.

In this application, OPG is seeking the Board's approval to close $1,452.6M in capital expenditures (in-service) (see line 5 of Table 10) to the test period rate base. OPG states that the cost above the original budget arose entirely from the fact that the rock conditions encountered during construction were worse than OPG reasonably anticipated.[8]

The Board's consideration of the costs of the Niagara Tunnel Project is guided by section 6(2)4 of O. Reg. 53/05, which states:

> The Board shall ensure that Ontario Power Generation Inc. recovers capital and non-capital costs, and firm financial commitments 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.

The OPG Board of Directors approved the expense of $985.2M in 2005, prior to the Board's first order in 2008. OPG states that the issue before the Board is whether the $491.4M in expense beyond the $985.2M was prudently incurred. None of the parties have disputed this assertion.

The PWU submitted that the geological investigations and studies undertaken were appropriate and that OPG's conduct during and after the differing subsurface condition dispute was appropriate. PWU states the $491M additional cost was incurred reasonably and prudently. However, a number of parties found fault with OPG's management of the Niagara Tunnel Project, and argued for a range of disallowances to the amount closing to rate base.

Background

The initial budget for the project approved by OPG's Board of Directors in 2005 was $985.2M. There were a number of delays and cost over-runs resulting from

[8] Argument-in-Chief page 23

unanticipated subsurface conditions. Ultimately the total cost of the Niagara Tunnel Project was $1,476.6M of which OPG is seeking to close $1,452.6M to rate base in this application.[9] A summary of project costs is provided in the table below.

Table 10: Niagara Tunnel Project

	$ millions*	Pre- 2008 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Test Year	2015 Test Year	Total
1	Budget Approved/Revised by OPG Board	985.0	985.0	1,600.0	1,600.0	1,600.0	1,600.0	1,600.0	1,600.0	1,600.0	
2	Capital Expenditures	300.2	131.3	213.5	231.8	264.2	231.2	86.6	13.0	0.4	
3	Accumulated Capital Expenditures	300.2	431.5	645.0	876.8	1,141.0	1,372.2	1,458.8	1,471.8	1,472.2	
4	Gross Plant in-service (Opening Balance)	19.2	19.2	19.2	19.2	19.2	19.2	19.2	1,458.4	1,471.4	
5	Gross Plant additions	-	-	-	-	-	-	1,439.2	13.0	0.4	1,452.6
6	Gross Plant in-service (Closing Balance) **	-	-	-	-	-	-	1,458.4	1,471.4	1,471.8	

Source: OPG Reply Argument p.26 & Exh L-4.5-Staff-25

*Numbers may not add up due to rounding

** To calculate the total cost of the Niagara Tunnel Project, $4.6M in removal costs (treated as operating expenses) is added to the $1,472.2M in total capital(in-service) expenditures. This results in a Niagara Tunnel Project total cost of **$1,476.6M**. The $4.6 M is recorded in the Capacity Refurbishment Variance Account.

OPG's preparatory geotechnical investigation for a Niagara Tunnel began in 1983. The tunnel passes through geologically challenging conditions, including the Queenston shale formation. OPG's initial investigations included 59 boreholes and an exploratory adit (a test tunnel).

OPG undertook a request for proposal process in 2004/2005. The request for proposal mandated a tunnel boring process, which was a requirement of the environmental assessment. The request for proposal was based on OPG's geotechnical investigations and OPG's risk assessment analysis. Strabag AG of Austria and its wholly owned subsidiary Strabag Inc. ("Strabag") were the successful bidders.

Strabag's bid was based on a "design-build" approach, whereby OPG would hire a single firm (i.e. Strabag) to design and build the project to OPG's pre-established specifications.[10] The OPG Board of Directors approved the release of $985.2M, of which $112M was contingency. The business case presented to the OPG Board of Directors stated that the project economics compared favourably against other renewable generation options. The Design Build Agreement with Strabag was signed in August 2005. The new tunnel was projected to be in service by June 2010 and was

[9] The $24M difference is comprised of amounts added to rate base prior to 2008 and an amount attributed to OM&A.
[10] The other common approach is design-bid-build, whereby OPG would hire a firm to design the tunnel, issue a request for proposal on the basis of the design, and then select a firm to construct it.

expected to increase generation by 1.6 TWh. The initial cost of the tunnel itself, as reflected in the Design Build Agreement, was $622.6M to be paid to Strabag.

The terms of the Design Build Agreement were based in part on a Geotechnical Baseline Report. The purpose of the Geotechnical Baseline Report was to establish a contractual baseline for subsurface hydro-geological conditions. Initially OPG prepared a geotechnical baseline report which was included with the request for proposal and bidders including Strabag provided geotechnical baseline reports (based on OPG's report) with their bids – these are referred to in the evidence as Report A and Report B respectively. The final Geotechnical Baseline Report (sometimes referred to in the evidence as Report C) was negotiated jointly by OPG and Strabag as part of the Design Build Agreement. Unless otherwise specified, references to the Geotechnical Baseline Report in this Decision refer to this final Report C.

In the event that the actual subsurface conditions were found to be materially different from the conditions anticipated in the Geotechnical Baseline Report, the Design Build Agreement provided a number of potential remedies. If OPG agreed that there was a "differing subsurface condition", the parties could negotiate changes to the schedule and price. If OPG did not agree that there was a differing subsurface condition, the Design Build Agreement outlined a dispute resolution process, which included recourse to a third party Dispute Review Board.[11]

One of the subsurface issues addressed in the Geotechnical Baseline Report was "overbreak". Overbreak is the cracking and loosening of rocks above the tunnel boring machine[12] as it moves through the rock to create the tunnel. It was recognized by both OPG and Strabag that overbreak could be an issue, particularly in the Queenston shale formation through which portions of the tunnel were expected to pass. OPG's original assessment was that there would be approximately 45,000 m^3 of overbreak, whereas Strabag estimated only 15,000 m^3. In the final Geotechnical Baseline Report (which was part of the Design Build Agreement), the parties agreed to a figure of 30,000 m^3.

Construction began in September 2005. Excavation by the open tunnel boring machine commenced in September 2006. Starting in spring 2007, significant quantities of overbreak were reported, which resulted in delay and additional expense to Strabag. Strabag considered this excessive overbreak to be due to a differing subsurface

[11] Exh D1-2-1 Attachment 6, Design Build Agreement, sections 5.5-5.7.
[12] Exh D1-2-1 page 72

condition more significant than had been previously identified, and attempted to negotiate changes to the Design Build Agreement with OPG. By February 2008, it was clear that the parties would be unable to resolve the issue on their own, and the dispute was referred to a Dispute Review Board.

Strabag argued before the Dispute Review Board that one or more differing subsurface conditions existed based on five issues of dispute, including the excessive amount of overbreak. OPG's position was that no differing subsurface condition existed and that Strabag was at fault for the overbreak because it substantially modified its tunnel boring machine design and rock support from the original proposal.

The Dispute Review Board held that for three of the issues identified (large block failures, insufficient "stand-up" time, and an issue related to tunneling under the buried St. Davids Gorge) there was no differing subsurface condition. For the other two issues (excessive overbreak and the table of rock conditions and rock characteristics) the Dispute Review Board found that there was a differing subsurface condition. With respect to the differing subsurface conditions, the Dispute Review Board report stated:

> Since the development of the [Geotechnical Baseline Report] was the mutual responsibility of both Parties, we recommend that the Parties negotiate a reasonable resolution based on a fair and equitable sharing of the cost and time impacts resulting from the overbreak conditions that have been encountered and the support measures that have been employed. [13]

Following negotiation, OPG agreed to pay Strabag an extra $40M to resolve all issues to November 30, 2008 (Strabag had claimed additional costs of $90M). After considering several options, OPG determined that the best way to ensure the completion of the Project was to renegotiate the Design Build Agreement. The excessive amount of overbreak required tunnel profile restoration (infill to restore tunnel profile to a circular shape), realignment of the tunnel route, and additional cost and time. An Amended Design Build Agreement, based on target cost instead of fixed price, was approved by the OPG Board of Directors in May 2009. The total project cost estimate was revised to $1.6 billion, of which $985M was now allocated to Strabag for constructing the tunnel. The Amended Design Build Agreement moved the completion date for the project from June 2010 to June 2013. The supporting business case stated

[13] Exh D1-2-1 Attachment 7 page 18

that completing the tunnel was still economic when compared with alternative energy supply options.

Ultimately the tunnel was completed in March 2013, for less than the $1.6 billion revised cost. The final total cost for the Niagara Tunnel Project was $1,476.6M (see footnote to Table 10). Strabag earned a number of incentives for completing the project ahead of the revised schedule and for less than the revised budget.

As part of its application, OPG filed a report by Mr. Roger Ilsley, a geotechnical and tunnel expert. The report concluded that OPG's site investigations were appropriate and completed to professional standards. Similarly Strabag's design work was completed to professional standards.[14] Mr. Ilsley also appeared as a witness at the oral hearing.

Geotechnical Baseline Report

The submissions of Board staff, AMPCO, CME and SEC criticized the Geotechnical Baseline Report. OPG was solely responsible for the initial Report A which was the basis for the request for proposal and subsequent reports. The bidders provided Report B, a supplemented version of Report A, with their bids. The final Report C was agreed to by OPG and the successful bidder, Strabag. It was submitted that the contractually binding Report C was ambiguous and not in compliance with the *Geotechnical Baseline Reports for Construction – Suggested Guidelines*. AMPCO submitted that the ambiguity in the original Report A misled Strabag to propose open tunnel boring instead of closed tunnel boring and that OPG's expert, Mr. Ilsley, agreed in cross examination that Report C was ambiguous.[15]

As summarized in the Dispute Review Board's report:

> The [Dispute Review Board] agrees that the Table of Rock Conditions and Rock Characteristics is inadequate to be used for the identification of [Differing Subsurface Conditions] and, further, that the inclusion of such terms as the "closest match" and "all other conditions" essentially renders the concept of [Differing Subsurface Conditions] meaningless and makes the [Geotechnical Baseline Report] defective.[16]

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[14] Exh F5-6-1
[15] Tr Vol 2 page 53
[16] Exh D1-2-1 Attachment 7 page 18

OPG spent $57M on geotechnical investigations. OPG asserts that this was a considerable amount of investigation, and the results were unchallenged by five contractors who did not seek additional geotechnical data to submit their bids. Further, the geotechnical investigation and results were supported by Mr. Ilsley. The guidelines for geotechnical baseline reports recognize that it is not always possible to describe geologic conditions precisely. OPG stated that AMPCO's criticism that the geotechnical baseline report was misleading to bidders is incorrect as Strabag considered both closed and open tunnel boring.

In OPG`s view, the parties have not pointed to a single action that OPG took that was unreasonable in developing the Geotechnical Baseline Report.

Risk Management

The submissions of Board staff, AMPCO and SEC find fault with OPG's risk assessment process and the risk OPG assumed in the project. Some parties noted that OPG's contracting approach was a risk since tunnels in North America have traditionally been constructed using Design-Bid-Build contracts instead of Design Build. SEC observed that of the 59 borehole tests conducted, only 20 were located along the proposed route. SEC also questioned OPG's decision to rely on 1993 borehole data as testing methods and instrumentation had likely improved in the interim.

In OPG`s view the Design Build approach was selected to appropriately allocate project risk and to obtain as much upfront price certainty as possible. OPG stated that the criticisms of the vintage of borehole data are contrary to the evidence of Mr. Ilsley, who testified that while the electronic methods to record geotechnical results have improved, the tests themselves are unchanged.

OPG submitted that all the project risks identified by OPG were mitigated to low risk except subsurface conditions which remained at medium risk. OPG`s mitigation activity to move the risk from high to medium was the extensive field investigation over 10 years, the 3 stage geotechnical baseline report process and contingency for the tunneling work. While total project contingency was $112M, the contingency for the tunneling portion of the project was $96M. OPG stated that to mitigate to low risk would be costly. As OPG assumed full responsibility for geological conditions in design build, the parties submitted that OPG assumed too high a risk.

OPG replied that, "While it is clear in hindsight that OPG underestimated the potential severity of the rock conditions encountered, particularly the nature and extent of the overbreak, this occurred because the rock conditions were much more challenging than OPG, its experts and Strabag expected based on extensive geotechnical sampling and analysis, and not because OPG's risk identification and quantification efforts were deficient."[17]

Contract Renegotiation

Several parties submitted that OPG was not prudent in its renegotiations with Strabag and that the Amended Design Build Agreement did not reflect sharing of responsibility for losses as determined by the Dispute Review Board. SEC observed that few options were presented to the OPG Board of Directors and that the Amended Design Build Agreement was for all intents and purposes final when it was presented to the OPG Board.

When Strabag filed its claim for $90M, tunneling had advanced to the 3 km point. OPG had paid Strabag $40M, or $13.3M/km. CME observed that the Amended Design Build Agreement provided for an additional $243M for the remaining 7 km, or $34.7M/km. CME submitted that OPG should not have paid Strabag more than $13.3M/km for the remaining 7 km, and that the difference would result in a $149M disallowance.

A number of parties submitted that OPG could have achieved a better result through the Amended Design Build Agreement. OPG stated that the understanding of the parties with respect to sharing of risk is incorrect. At the end of three years of work, Strabag had a loss of $90M, which was settled by a $40M payment. Strabag finished the tunnel with what OPG characterized as a very small profit after an additional four years of work. OPG argued that CME`s understanding of additional costs per km are incorrect as the $90M claim did not include tunnel profile restoration, which had to be undertaken in addition to completion of the remaining 7 km.

OPG also argued that there would have been significant costs for terminating the Strabag contract. Mr. Ilsley referred to the Seymour-Capilano project in Vancouver which was rebid at 1.8 times the original cost for the remaining 40% of the work with potential litigation by the original contractor.[18]

[17] Reply Argument page 52
[18] Tr Vol 1 page 80

Disallowances Proposed by Parties

Board staff and the parties have proposed reductions to the rate base addition ranging from $50M to $407.4M:

- Energy Probe submitted that a $50M rate base addition reduction was appropriate as OPG's use of the design build model limited its ability to terminate Strabag.
- Board staff listed 7 items to deduct from rate base additions totaling $105M, including the $40M paid to Strabag pursuant to its claim, design costs, overhead costs and carrying charges.
- In addition to $149M related to contract renegotiation, CME agreed with several of the items that Board staff proposed for disallowance, and proposed a $208.5M total disallowance.
- SEC proposed that rate base additions should be reduced by $245.7M, i.e. half of the amount in excess of the originally approved $985.2M
- AMPCO's submission listed 9 items, including the entire diversion tunnel expense beyond the original estimate of $280.3M and $10.8M paid to OPG's representative, Hatch. AMPCO submitted that $407.4M should be removed from OPG's proposed rate base additions.

OPG replied that all of these disallowances should be rejected, and that the analysis of Board staff and parties is inadequate. Other than Mr. Ilsley, there were no expert witnesses that gave evidence related to the Niagara Tunnel. OPG argued that the parties did not fully understand the evidence and the arguments are selective reviews based on hindsight. Although the parties claimed imprudence, in OPG's view the parties failed to identify a single action that OPG took or failed to take that was unreasonable at the time.

OPG stated that the Niagara Tunnel Project costs are reasonable and that "if the rock conditions had been known in advance with perfect foresight, the tunnel would have cost at least what OPG paid and may have cost more."[19]

[19] Reply Argument page 39

Board Findings

The Board finds that $1,364.6M in Niagara Tunnel Project capital expenditures (in-service) should close to rate base in the test period. This represents a disallowance of $88.0M (or approximately 6%) from the $1,452.6M proposed by OPG. The disallowances are based primarily on OPG's response to the Dispute Review Board's decision and recommendations, in particular OPG's decision to pay $40M for claims prior to December 2008, and the terms negotiated with Strabag in the Amended Design Build Agreement.

The Board accepts OPG's argument that the Board's review of the Niagara Tunnel Project is a "prudence review", and that the Board is not permitted to use hindsight when considering OPG's actions. The Board also accepts OPG's assertion that, pursuant to section 6(2)4 of O. Reg. 53/05, only the $491.4M in expenses incurred after 2008 are subject to review. As a result, the Board will not opine on the actions of OPG prior to the commencement of the Board's regulation of OPG in 2008.

Settlement of Strabag's $90M Claim

In its report, the Dispute Review Board recommended "that the Parties negotiate a reasonable resolution based on a fair and equitable sharing of the cost and time impacts resulting from the overbreak conditions that have been encountered and the support measures that have been employed. Both Parties must accept responsibility for some portion of the additional cost, but at the same time the Contractor must have adequate incentives to complete the Work as soon as possible."[20]

Based in part on this recommendation, OPG decided on two courses of action. First, it agreed to settle all of Strabag's pre-December 2008 claims for $40M (Strabag had claimed $90M). Second, OPG determined that the best solution moving forward was to renegotiate the Design Build Agreement with Strabag. The resulting Amended Design Build Agreement target cost was $985M plus incentives (compared with the Design Build Agreement contract cost of $622.6M).

The Project was completed pursuant to the terms of the Amended Design Build Agreement. Strabag earned the incentives described in the Amended Design Build

[20] Exh D1-2-1 Attachment 7 pages 18-19

Agreement. Overall OPG estimates that Strabag earned a profit of approximately $26M on the Project as a whole.[21]

Several parties questioned whether the Amended Design Build Agreement appropriately allocated responsibility for the additional costs between OPG and Strabag. OPG's witnesses testified that absent a successfully renegotiated Design Build Agreement, Strabag would have likely walked away from the Project. OPG would then have been forced to find a new contractor to complete the Project. OPG expected that the costs of finding a new contractor at that stage of the Project would have greatly exceeded the cost of renegotiating the Design Build Agreement with Strabag.

The Board is not satisfied that paying Strabag $40M for its claims up to December 2008 was prudent. This Board finds that the non-binding recommendations of the Dispute Review Board were reasonable, and that some level of shared responsibility between OPG and Strabag was appropriate. However, paying a $40M settlement (44% of Strabag's $90M claim) is excessive in the Board's view. There were five issues of dispute that were referred to the Dispute Review Board. The Dispute Review Board found that OPG was not responsible for three of the five issues and that OPG had only joint responsibility for the remaining two issues. No evidence was filed on the relative value or cost of the five issues. OPG's witnesses testified that the individual issues were not quantified.

As a result of the contract renegotiation with Strabag, OPG had the right to audit Strabag's claimed losses of $90M. To the extent that the $90M was not substantiated in the audit, the $40M payment could be reduced proportionately. OPG's witnesses testified that OPG's internal auditors conducted the audit and found that a total of $12.6M was not associated with legitimate expenses, resulting in a loss of only $77.4M.[22] The auditors did not recognize inter-company transfers within Strabag's organization, thereby reducing the amount from $90M to $77.4M.[23] OPG's evidence was that they could reduce the $40M settlement proportionately based on the audit, but did not do so.[24]

The Board is unable to find that a $40M settlement of Strabag's claim was prudently incurred. In the absence of information regarding the costs attributable to each of the

[21] Tr Vol 2 page 124
[22] Exh L-4.5-SEC-41 Attachment 16
[23] Tr Vol 2 page 149
[24] Exh D1-2-1 page 106

five issues, the Board must use its judgment of what is a reasonable amount. In determining the amount, the Board has decided to utilize the findings of the Dispute Review Board. As a result, the Board finds that OPG's ratepayers should not pay any amount for the three issues which OPG was not responsible, but should pay 50% of two issues for which OPG was jointly responsible. In addition, the Board is persuaded by the results of OPG's audit and considers the $77.4M to be the appropriate starting point for the Board's calculation, not the $90M claim by Strabag. There was no evidence or testimony provided supporting Strabag's claimed amount. As a result, the Board finds that ratepayers should only pay 20% of the $77.4M audited amount, or $15.5M. In addition, the Board denies the associated carrying costs of the disallowed $24.5M,[25] which results in a reduction of another $3.5M.[26] The Board finds this disallowance of $28.0M reasonable given the evidence provided.

Terms of the Amended Design Build Agreement

The Board finds that not all of the costs associated with the Amended Design Build Agreement should be passed on to ratepayers.

The Board accepts that absent a revised Design Build Agreement, there was a possibility that Strabag would have abandoned the Project. Had that occurred, the cost of completing the Project with a new contractor might well have exceeded the costs of the Amended Design Build Agreement. In the Board's view, however, the possibility of project abandonment and the speculation of the financial impact of this does not justify the level of incentives offered to Strabag in the Amended Design Build Agreement. The question is not: Would it have cost OPG more had Strabag walked away? Instead, the salient question is: Could OPG have achieved better terms than it did in negotiating with Strabag to move forward after the Dispute Review Board findings?

The risk of the contractor abandoning the Project was recognized in the original 2005 Business Case. The project risk profile identified this risk as "medium" before mitigation, and "low" after mitigation. The mitigation activity described in the project risk profile was a requirement for the contractor to provide bonds and/or letters of credit as security, and to provide a parental guarantee. As part of the Design Build Agreement, Strabag was required to post a letter of credit for $70M, and provide a parental indemnity guaranteeing Strabag's performance of the contract and indemnifying OPG

[25] $40M – (20% x $77.4M)
[26] $24.5M x 5.25% x 33/12 months

for any damages resulting from a breach by Strabag.[27] The Indemnity Agreement provided that Strabag's parent company "irrevocably and unconditionally agrees to indemnify and save harmless OPG from and against all costs, damages, expenses, losses, liabilities, demands, claims, suits, actions, proceedings, judgments and obligations (including, without limitation, legal fees and expenses) arising in respect of any breach" of the Design Build Agreement. The Indemnity Agreement further allowed OPG to make credit inquiries about the parent company, and provided OPG with three years of financial statements.[28]

OPG's witnesses further confirmed that Strabag would suffer serious repercussions were it to walk away from the Project, including being sued by OPG for breach of contract, and suffering a serious blemish on its business reputation.[29]

Strabag, therefore, had very strong incentives to reach an agreement with OPG to find a way to complete the Project. Walking away from the Project would have been an extremely expensive and unpalatable option for Strabag, and for its parent company.

Under these circumstances, the Board finds that the incentives offered to Strabag through the Amended Design Build Agreement were excessive. OPG understood that a contractor default was a potential risk, and indeed it took steps that should have mitigated that risk through a letter of credit and a comprehensive parental indemnity. However, when it came time to renegotiate the Design Build Agreement, OPG did not properly use its leverage to secure a more favourable deal. The Board will disallow recovery of $60M.[30] The Board is mindful of the Dispute Review Board's recommendation that Strabag have appropriate incentives to complete the work. However, in the Board's view the Amended Design Build Agreement provided adequate "incentive" even without the specific incentive clauses. OPG agreed to pay Strabag hundreds of millions of extra dollars more than was provided for in the original Design Build Agreement. In the Board's judgment, the provision for incentives above this was not necessary and not prudent.

The total disallowance related to the capital expenditures of the Niagara Tunnel Project is $88.0M, which the Board finds to be imprudently incurred. The Board approves

[27] Exh D1-2-1 page 37
[28] Indemnity Agreement – Appendix 4.1(e) to the Design Build Agreement.
[29] Tr Vol 2 pages 122-123
[30] Exh D1-2-1 Attachment 9 - $40M schedule and cost performance incentive, $10M interim completion fee, and $10M substantial completion fee

$1,364.6M as the amount of Niagara Tunnel Project capital expenditures (in-service) to close to rate base in the test period.

2.5 Hydroelectric Other Revenue

(Issue 7.1)

OPG earns revenue from a number of sources other than through the regulated payment amounts for hydroelectric generation. These sources of other revenue include ancillary services, segregated mode of operations and water transactions.

The historical and forecast other revenues for the previously regulated and newly regulated hydroelectric facilities are summarized in the following table.

Table 11: Hydroelectric Other Revenue

$million	2010 Actual	2011 Actual	2012 Actual	2013 Budget	2013 Actual	2014 Plan	2015 Plan
Previously Regulated Ancillary Services	26.2	22.2	20.8	17.8	37.1	18.1	18.5
Seg Mode of Operation	-0.9	1.7	-0.8	1.6	4.1	0.0	0.0
Water Transactions	5.5	7.5	1.6	6.0	1.0	1.7	1.7
HIM Adjustment				6.5	6.5		
Total	**30.8**	**31.4**	**21.6**	**31.9**	**48.7**	**19.8**	**20.2**
Total: Exhibit N1 Update (Ancillary Services: $32.2M - 2014, $32.9M - 2015)						**33.9**	**34.6**
Newly Regulated Ancillary Services	**26.4**	**26.1**	**25.9**	**22.2**	**35.7**	**22.7**	**23.1**
Source: Exh G1-1-1, Exh L-1-Staff-2, Exh N1-1-1							

The IESO purchases the following ancillary services from OPG: black start capability, reactive support/voltage control service, automatic generation control and operating reserve. A forecast of the revenues from ancillary services is applied as an offset to the hydroelectric revenue requirement. Differences between the forecast and actual revenues are recorded in the Ancillary Services Net Revenue Variance Account – Hydroelectric. OPG has proposed that the account also apply to the newly regulated hydroelectric facilities.

The Exhibit N1 update is the result of higher forecast revenue for operating reserve and a new contract for regulation service, resulting in an increase in ancillary services revenue forecast for the previously regulated hydroelectric facilities of $14.1M in 2014 and $14.4M in 2015.

In the current application OPG has applied an escalation factor of 2% to the 2013 ancillary services budget amount to determine the forecast for 2014, which was escalated to determine the 2015 forecast. Both AMPCO and LPMA submitted that the forecast should be based on 2013 actuals and then escalated as proposed by OPG. CME submitted that the forecast should be based on the average of 2011-2013 actuals and then escalated as proposed by OPG. In response, OPG stated that some of the services are market based and some are contractual, and that forecasting requires more rigor than reference to historical values.

Segregated mode of operation transactions occur at the Saunders GS. Units at Saunders can be segregated, when pre-arranged, to serve the Hydro Quebec control area. OPG has forecast revenue from segregated mode of operation on the basis of a three year rolling average (2010-2012). AMPCO, CME and LPMA have proposed test period forecasts based on a three year rolling average that includes 2013 actuals. OPG argued that these submissions are opportunistic and would not have been made if the 2013 actuals reduced the average.

Water transactions between OPG and the New York Power Authority allow the two parties to use a portion of the other's share of water for electricity generation. In the previous proceedings, water transaction forecasts were based on the average of the three historical years. In the current application, water transaction volumes are forecast to decrease by 65% due to the diversion capability of the Niagara Tunnel which went into service in March 2013. OPG's forecast is based on the 2010-2012 average actual water transactions reduced by 65%. CME submitted that the forecast should be based on 2011-2013 average actuals.

Board staff observed that the historical other revenue variances were mainly due to ancillary services, for which there is a variance account. Board staff submitted that the proposed hydroelectric other revenues were appropriate.

Board Findings

The Board accepts the Exhibit N1 forecast revenues of $32.2M in 2014 as a result of ancillary services from previously regulated assets and $22.7M from the newly regulated assets, and $32.9M and $23.1M respectively in 2015 for these assets. The Board notes that the Ancillary Services Net Revenue Variance Account will continue throughout this period, accounting for any changes in revenues from the activities.

With respect to revenues from Segregated Mode of Operation, the Board will continue with the methodology established by the Board in EB-2007-0905 which uses a three-year historical average for the forecasting of 2014 and 2015. However, the Board will use the most recent historical actuals in calculating this average, thus the three years will be 2011, 2012 and 2013. This results in net revenue of $1.7M from segregated mode of operation for each of 2014 and 2015.

For net revenue from water transactions the Board accepts a departure from the methodology approved by the Board in EB-2007-0905 and EB-2010-0008, as the evidence is compelling that water transactions will be decreased as a result of the Niagara Tunnel being in-service. Similar to the determination of the segregated mode of operation forecast, the Board will use the most recent historical actuals for 2011, 2012 and 2013. As the Niagara Tunnel came into service in March of 2013, the 65% reduction is only applied to one quarter of the 2013 water transaction revenue. Hydroelectric Other Revenue of $1.3M related to water transactions will be included in each of 2014 and 2015. Once further actual data is available with the Niagara Tunnel in-service, this reduction by 65% should prove to be unnecessary and the previous methodology of the three year historical average may again be applicable.

As per the Board's findings in this Decision with respect to a revised methodology for the hydroelectric incentive mechanism, additional other revenues of $39M and $48M shall be appropriately allocated by OPG between the previously and newly regulated hydroelectric facilities and included in the revenue requirement determination for 2014 and 2015.

3 NUCLEAR FACILITIES

3.1 Nuclear Production Forecast

(Issue 5.5)

A key component of this Decision is the Board's determination of the appropriate nuclear production forecast for the determination of the payment amounts. OPG used the same methodology to determine the production forecast as in the previous proceeding. This resulted in a forecast of 48.5 TWh for 2014 and 46.1 TWh for 2015. OPG's historical nuclear production and test period production forecast are summarized in the following table.

Table 12: Nuclear Production Forecast

TWh	2010 Plan	2010 Actual	2011 Approved	2011 Actual	2012 Approved	2012 Actual	2013 Budget	2013 Actual	2014 Plan	2015 Plan
Darlington	27.8	26.5	28.9	29.0	29.0	28.3	26.9	25.1	28.4	26.1
Pickering	20.3	19.2	22.0	19.7	23.0	20.7	21.1	19.6	21.3	21.9
Total		**45.7**	**50.9**	**48.7**	**52.0**	**49.0**	**48.0**	**44.7**	**49.7**	**48.0**
Exhibit N1 Update - Darlington									28.1	24.7
Exhibit N1 Update - Pickering									20.9	21.3
Total - revised N1									**49.0**	**46.1**
Exhibit N2 - Darlington (no change from N1)									28.1	24.7
Exhibit N2 Update - Pickering									20.4	21.3
Total - revised N2									**48.5**	**46.1**
Sources: Exh E2-1-2, Exh L-1-Staff-2, Exh N1-1-1, Exh N2-1-1										

OPG's test period forecast includes a 0.5 TWh adjustment (a reduction) in each year for major unforeseen events. This level of adjustment was approved for the first time for the 2011-2012 test period in the Board's previous decision.

The Exhibit N1 update is based on selected updates from the 2014-2016 business plan. The number of planned outage days at Pickering increased by 86.6 days which reduced the test period production forecast by 1.0 TWh. Darlington's production forecast was reduced by 1.6 TWh due to an increase in planned outage days and a reduction of 0.28 TWh related to higher lake water temperature.

The Exhibit N2 update is based on a further increase of 21 planned outage days at Pickering and a higher forecast of forced loss rate at Pickering resulting in a production forecast decrease of 0.5 TWh in 2014.

No party proposed changes to the Pickering production forecast.

Board staff submitted that the 61.9 day increase in outage days at Darlington is responsive to OPG senior management business planning direction to consider the significant historical variances. The major 2015 Darlington outage is related to moving the planned vacuum building outage from 2021 to 2015. OPG states that the length of the 2015 vacuum building outage is dependent on emergency service water piping work and emergency coolant injection valve replacement. Board staff questioned why this critical path work was not identified in the initial application. Board staff submitted that a production forecast reduction of only 0.28 TWh related to higher lake water temperature was appropriate for the test period.

The Board staff submission was supported by most parties. However, AMPCO submitted that the Darlington production reduction related to higher lake water temperatures should not be approved. In AMPCO's view the 2014-2016 business plan is based on the actuals prior to 2013. The actual production losses due to high lake water temperature in 2013 are much lower than 2012, and AMPCO submitted that the Board should not approve the 0.28 TWh reduction.

The challenge of the nuclear production forecast by OPG senior management is part of the review that all production forecasts are subject to, and the process surrounding the update was not different. OPG submitted that the adjustment was the result of rigorous reassessment and lessons learned from recent outages. While the specific tasks on the critical path are not discussed in detail in the pre-filed evidence, the complexity of the vacuum building outage is discussed. OPG observed that the Board staff submission focused on the tasks during the vacuum building outage but ignored the updated evidence that 22 of the 61.9 outage day increase is related to other Darlington outages.

Production losses related to lake water temperature are based on reviewing historical performance. OPG submitted that the evidence is based on the best information available and that AMPCO's submission should be given no weight.

Board Findings

The Board approves a nuclear production forecast of 49.0 TWh for 2014 and 46.6 TWh for 2015 to be used in the calculation of payment amounts.

OPG's forecast as filed in the updated impact statements (Exhibits N1 and N2) is accepted with one exception as discussed later in this Decision. The forecast as amended by updates filed in December 2013 and May 2014 was based on the business plan for 2014 to 2016. This business plan addresses the historically large and persistent gap between forecast and actual nuclear production. The revised forecast is in response to Senior Management's direction and was to ensure that the planned outage days recognize the scope and complexity of the proposed work. The revised forecast in Exhibit N2 reflects a more complete understanding of the work required at the Pickering units. As a result, the Board agrees with OPG that the nuclear production forecast represents "OPG's most complete and accurate forecast for 2014 and 2015".[31]

The decrease in production forecast for 2015 is the result of the decision to combine work at Darlington to include a vacuum building outage, a station containment outage and critical path work related to emergency service water piping work and emergency coolant injection valve replacement. The Board finds that OPG has demonstrated that combining this work results in net positive benefits and has been already approved by the Canadian Nuclear Safety Commission. The Board accepts that this work should be undertaken in 2015 and will result in a reduced forecast of nuclear production [32]

The one exception to accepting the nuclear production forecast as proposed by OPG is that the Board will remove the adjustment for major unforeseen events of 0.5 TWh for each of 2014 and 2015. This adjustment is tied to the Board's acceptance of OPG's evidence that the forecasts are based on OPG's best evidence which explains the technical and operational reasons for its updates to the production forecast, and that the resulting forecast is as accurate as possible. It follows then, that with the confidence OPG has in its forecast and the more detailed scrutiny which was undertaken in producing this forecast, that an allowance for unforeseen events is no longer required.

The Board finds that the argument of some parties for further adjustments to the forecast, for example due to water temperatures, is not compelling.

[31] Argument-in-Chief page 63
[32] Argument in Chief page 63

The quantity of nuclear production of 49.0 TWh in 2014 is equal to the highest amount over the period 2008 to 2013 and is therefore considered by the Board to be achievable and reasonable. The forecast amount of 46.6 TWh for 2015 is also considered by the Board to be reasonable.

3.2 Nuclear OM&A and Benchmarking

(Issues 6.3 and 6.4)

OPG seeks approval of operating costs of $2,957.5M in 2014 and $2,985.2M in 2015 for the nuclear facilities. The nuclear facility operating costs include base, project and outage OM&A, Darlington Refurbishment and New Nuclear OM&A, an allocation of corporate support and centrally held OM&A, nuclear fuel costs, Pickering Continued Operations costs, and depreciation and taxes. This section of the Decision addresses nuclear OM&A costs and benchmarking. The other components of nuclear operating costs are discussed later in this Decision.

OPG's historical and forecast OM&A for the nuclear facilities are summarized below. OPG applied for a total OM&A budget $2,401.4M for 2014 and $2,419.8M for 2015. The compound annual growth rate from 2010 actual to 2015 forecast is 3.5%.

Table 13: Nuclear OM&A

$million	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Plan	2015 Plan
Base	1,181.4	1,249.1	1,102.6	1,127.7	1,151.1	1,154.0
Project	142.7	111.6	111.5	105.7	113.9	106.4
Outage	278.2	215.0	214.3	277.5	262.7	330.7
SubTotal Operations	1,602.3	1,575.7	1,428.4	1,510.9	1,527.7	1,591.1
Darlington Refurbishment	3.2	2.6	2.8	6.3	19.6	18.2
Darlington New Nuclear	23.2	15.7	24.7	25.6	-	-
Corporate Costs	226.5	233.1	408.4	428.3	433.9	417.4
Centrally Held Costs	161.6	267.1	342.7	409.9	418.2	419.8
Asset Service Fee	24.5	22.1	23.0	22.7	23.3	26.8
SubTotal Other	439.0	540.6	801.6	892.8	895.0	882.2
Total OM&A	**2,041.3**	**2,116.3**	**2,230.0**	**2,403.7**	**2,422.7**	**2,473.3**
Exhibit N1 Update					**2,491.8**	**2,531.3**
Exhibit N2 Update					**2,401.4**	**2,419.8**
Sources: Exh L-1-Staff-2 Table 19, Exh N2-1-1						

Some parties proposed reductions to the OM&A forecast. These reductions ranged from $100M in the test period (Board staff), $100M per year (SEC and LPMA), $150M per year (CME), to $1.225 billion (GEC). The supporting rationale for the reductions was poor benchmarking results or excessive compensation. Part of Board's staff's proposed reduction was also based on excessive corporate support cost. OPG replied that the proposed reductions are punitive and that none of the parties challenged specific evidence related to base, project and outage OM&A.

Environmental Defence submitted that $1 billion of the test period OM&A expense is related to Pickering. It argued that this amount is unreasonable as other power sources, for example, conservation and imports from Quebec, are more cost-effective. Environmental Defence submitted that the operation of Pickering will also curtail renewable power generation. OPG argued that it is improper to determine payment amounts on the basis of the cost of other sources of power. Further, there is an insufficient record to assess cost and practicality of other sources of power.

Benchmarking

Benchmarking of the nuclear facilities is mandated by the August 17, 2005 Memorandum of Agreement between OPG and the Shareholder.[33]

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

The Memorandum of Agreement further requires that:

> OPG will annually establish 3 –5 year performance targets based on operating and financial results as well as major project execution. Key measures are to be agreed upon with the Shareholder and the Minister of Finance. These performance targets will be benchmarked against the performance of the top quartile of electricity generating companies in North America.

[33] Appendix C of this Decision

In the first cost of service proceeding, the Board found that the benchmarking filed was insufficient. As a result, the Board directed OPG to retain an expert to prepare a comprehensive benchmarking analysis of OPG's nuclear operations. OPG filed benchmarking reports that assessed 2008 performance prepared by ScottMadden Inc. for the EB-2010-0008 proceeding. OPG has adopted the ScottMadden reporting format and annually benchmarks its nuclear performance against "20 performance metrics and then sets operational, financial and generation performance targets that will move OPG nuclear closer to top quartile industry performance over the business planning period as part of top-down business planning process adopted in response to ScottMadden's work."[34]

The results of OPG's benchmarking of three key metrics for the nuclear facilities for the period 2008 to 2013, and the targets for 2014 and 2015 are summarized in the following table.[35] The three key metrics identified by ScottMadden are World Association of Nuclear Operators Nuclear Performance Index, Unit Capability Factor and Total Generating Costs per MWh. Note that Pickering A and B were combined by OPG after 2010, and therefore the units are not ranked separately by OPG after that time (though ScottMadden had created separate targets for Pickering A and B in its 2009 report). OPG has performed very poorly on all three of the key metrics.

[34] Reply Argument page 139
[35] Undertaking J5.2

Table 14 – Summary of Nuclear Benchmarking

	---Rolling Actual Results---						---Annual Target ---		
	a	b	c	d	e	f	g	h	i
Darlington	2008	2009	2010	2011	2012	2013	**2014** "Scott Madden" Phase 2 Report	**2014** 2013-2015 Business Plan	**2015** 2013-2015 Business Plan
WANO NPI (Index)	95.67	95.10	94.10	92.80	96.30	90.75	98.60	97.90	96.10
2-Year Unit Capability Factor (%)	91.99	90.20	89.40	89.60	92.00	90.44	93.30	93.50	86.30
3-Year Total Generating Costs ($/New MWh)	30.08	32.77	33.55	33.05	31.67	34.42	36.75	36.21	42.78
Pickering									
WANO NPI (Index)	60.90	67.17	64.30	66.10	64.70	67.52	77.83	72.00	74.20
2-Year Unit Capability Factor (%)	67.65	74.47	74.57	72.50	75.62	75.77	82.10	79.90	82.10
3-Year Total Generating Costs ($/New MWh)	67.05	66.42	65.62	65.86	67.16	67.18	66.84	66.08	60.25
Pickering A									
WANO NPI (Index)	60.84	61.10	47.70				70.90		
2-Year Unit Capability Factor (%)	56.60	68.00	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 (Scott Madden Phase 1)
Column b - EB-2010-0008 Undertaking J3.5 Attachment 1 page 4
Column c - Exh L-6.4-SEC-92
Column d - Exh F2-1-1 Attachment 1 page 3
Column e - Exh L-6.4-SEC-92
Column f - Vol 5 Oral Hearing Transcript June 18, 2014
Column g - EB-2010-0008 Exh F2-1-1 Attachment 1 (Annual Targets agreed based on Scott Madden for inclusion in 2010-2014 Business Plan)
Column h- EB 2013-0321 Exh F2-1-1 page 15 (Annual Targets)
Column i - Exh F2-1-1 Attachment 2 (2013-2015 Nuclear Business Plan - Annual 2015 Target)

OPG Nuclear	2008	2011
WANO NPI (Index)	17th out of 20	24th out of 27
2-Year Unit Capability Factor (%)	18th out of 20	25th out of 28
3-Year Total Generating Costs ($/New MWh)	16th out of 16	12th out of 14

Table 14 was initially prepared by Board staff for cross examination and subsequently reviewed by OPG and filed as undertaking J5.2.

Column g of Table 14 lists the 2014 targets OPG established with ScottMadden in 2009. It was recognized at the time that the targets would not result in best quartile performance but that achievement of the targets would close the gap. Board staff submitted that OPG's performance to date and the test period targets fall short of these targets. During the oral hearing, OPG's witness indicated that achieving top quartile is not an objective.[36] Board staff submitted that the Memorandum of Agreement could have referred to benchmarking without referring to top quartile, and that it is clearly the shareholder's expectation that OPG set targets to achieve top quartile. CME submitted that OPG's performance as set out in Table 14 falls far short of what ratepayers should reasonably expect. CME noted that in the previous proceeding, the Board sent a signal that OPG must take responsibility for improving its performance by reducing the nuclear payment amounts by $145M.

Using data in the benchmarking report for 2011 filed with the application,[37] Board staff estimated that annual nuclear costs would be reduced by $300M if OPG's total generating costs were at the midpoint for the comparators. Board staff did not propose disallowances of this magnitude, but submitted that it would be reasonable for the Board to expect that OPG's efficiency and productivity should be improving. Recognizing that total generating cost includes OM&A, fuel and some capital costs, CME submitted that an OM&A reduction of $150M per year was appropriate.

The Pickering units, in particular units 1 and 4, perform poorly compared to the targets established. GEC submitted that, while OPG and the shareholder may want to run uneconomic plants, the issue before the Board is whether it is appropriate to allow full recovery of the costs OPG proposes. GEC estimated that test period OM&A requirements would be reduced by $1.225 billion based on industry median levels for Pickering, and reduced by $322M if Pickering operated at OM&A levels similar to Darlington. GEC submitted that OPG should be required to study the economics of a range of Pickering shutdown scenarios for the next proceeding.

OPG stated that there have been positive developments in benchmarking and cited Pickering unit-specific forced loss rate and unit-specific capability factor improvements. It is premature to state that OPG will not meet 2014 targets for the key metrics. OPG expects that Darlington 2014 total generating cost will be marginally below best quartile and that the total generating cost gap at Pickering has narrowed. OPG argued that the disallowances proposed by Board staff and CME should be rejected as the benchmarking report for 2011 does not reflect the impact of the Business Transformation initiative. OPG also referred to the Goodnight Consulting Inc. staffing study. OPG indicated that Goodnight determined that due to technology differences,

[36] Tr Vol 6 pages 119-120
[37] Exh F2-1-1 Attachment 1

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

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

Board Findings

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

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

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

[38] Reply Argument page 134

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

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

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

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

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

[39] Tr Vol 6 page 13

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

3.3 Nuclear Fuel

(Issue 6.5)

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

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

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

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

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

[40] Exh F5-2-1

appropriate and that Longenecker found to be “good utility practice” in its study. Board staff suggested OPG should also provide details regarding planning for lower nuclear fuel inventory requirements for when Pickering will cease operations. OPG argued that the Longenecker study was completed in 2012 and as Board staff had no issues with the findings, there was no need for a new study.

Board Findings

The Board finds that OPG met the directive in the EB-2010-0008 decision when it commissioned Longenecker, an independent consultant, to conduct a review of OPG’s uranium procurement program.

The Board accepts the findings in the Longenecker & Associates report which concludes that OPG’s procurement is undertaken in a professional manner and that its strategy is prudent. The Board is encouraged that three of the four recommendations made in the report have been accepted and are being implemented. The one recommendation not being pursued by OPG is with respect to “off-market” transactions. The Board agrees this recommendation is inconsistent with OPG’s policy and the government’s procurement guidelines to which it is subject.

The Board will not make any changes to OPG’s proposed inventory target levels, which will be achieved by the end of 2015. The observation that the reduced inventory levels may be achieved by the end of 2014 is unsupported.

The Board does not agree that a study to examine various nuclear fuel cost management options in anticipation of the changes once the Pickering station is closed should be undertaken at this time. Given the station is not proposed to close until 2020, the Board agrees with OPG that undertaking such a study would not be a reasonable expenditure of time and money.

Although several parties put forward suggestions for reducing the nuclear fuel cost expenditures, there was no substantial evidence provided regarding the options proposed. As OPG points out, fuel expenses are a function of production, so a simple comparison of costs in the previous three years is not a suitable predictor of future costs.

The Board finds OPG's proposed costs of $266.5M for 2014 and $260.5M for 2015 to be reasonable and are therefore accepted. However the final nuclear fuel cost will increase due to the increased nuclear production forecast the Board has set. OPG shall confirm the final test period nuclear fuel costs in the payment amounts order process.

3.4 Pickering Continued Operations

(Issue 6.6)

Pickering Continued Operations will extend the life of Pickering units 5 to 8 from 2015/2016 to 2020. OPG seeks approval of 2014 OM&A expense of $38.9M for the project which would bring the total project cost to $192M.

OPG filed an updated 2012 business case for the project.[41] OPG reported that the net system benefit of Pickering continued operations is $520M. An OPA letter filed with the application suggested that the cost advantage of Pickering continued operations is $100M. The OPA did not provide oral testimony in the proceeding, but did file written responses on July 25, 2014 to questions raised by GEC relating to Pickering continued operations.

Board staff submitted that the test period expenditures are appropriate and that for the test period, the Board should rely on the Long-Term Energy Plan which states;

> The continued operation of Pickering facilitates the refurbishment of the first units at Darlington and Bruce by providing replacement capacity and energy without greenhouse gas emissions while managing prices. However, an earlier shutdown of the Pickering units may be possible depending on projected demand, the progress of the fleet refurbishment program, and the timely completion of the Clarington Transformer Station.[42]

AMPCO submitted that the net present value of continued operations is high, as the analysis did not consider sunk costs of $140M, a low demand scenario and risk related to pressure tube and calandria contact. AMPCO did not support any continued operations expenditure as it believes that the net present value of continued operations is a cost not a benefit. OPG argued that the business case included contingency for the issue of the potential risk associated with the pressure tube and calandria contact.

[41] Exh F2-2-3 Attachment 1
[42] Exh KT2.2 page 30

GEC observed that there is a considerable difference between the continued operations benefit determined by OPG and the OPA. GEC questioned the factors analyzed in the sensitivity analysis. In particular, GEC questioned whether the full cost of surplus baseload generation was considered by OPG and the OPA. In GEC's view, the Board should not approve payment amounts that have a perverse effect on ratepayers. As the economic benefit of continued operations is questionable, GEC submitted that the incremental cost of running Pickering in the test period ($126M in 2014 and $310M in 2015) should be disallowed.

OPG argued that OPA analysis did consider potential surplus energy and that this was confirmed in the written responses filed by the OPA on July 25, 2014.

GEC recognizes that operation of some Pickering units has system planning benefits, however, as units 1 and 4 (formerly Pickering A) under-perform on all benchmarking indicators versus units 5 to 8 (formerly Pickering B), GEC submitted that the Board should not "reward" OPG for the continuing losses with respect to units 1 and 4. OPG replied that it operates Pickering as one station and that the Long-Term Energy Plan includes Pickering in-service beyond the test period.

GEC submitted that $6.6M of test period expense allocated to Pickering for the fuel channel life extension project should be allocated to Darlington as the additional fuel channel life is not required for Pickering station life of 2020. However, OPG argued that an objective of the fuel channel life extension project is to operate all Pickering units to 2020 without a life management outage on any unit.

In the event the Board is not prepared to implement cost reductions related to Pickering, GEC submitted that the Board should require OPG to provide, in the next payment application, a detailed analysis of the net benefits of continued operation of Pickering units. GEC further submitted that the analysis should consider shutdowns of either the A or B units or all units, including staffing considerations. OPG argued that the study should not be ordered and that the Board should rely on the Long-Term Energy Plan.

Board Findings

The Board approves the OM&A costs in the amount of $38.9 M to enable the completion of the initiative to extend the operating life of Pickering units 5 to 8 to the year 2020. The Board finds these costs to be prudent and notes that this initiative is on time and on budget to be completed by the end of 2014.

The 2014 costs to complete the continued operations initiative include Fuel Channel Life Extension costs. The Board does not accept GEC's argument that these should be disallowed or reallocated to Darlington. OPG's evidence demonstrates that these costs are related to Pickering continued operations.

It is important to recognize that the extension of the Pickering units is consistent with the Province of Ontario's Long-Term Energy Plan. Further, benefits from Pickering continued operations were confirmed by the OPA. Lastly, the continued operations of Pickering has been reviewed by the Canadian Nuclear Safety Commission resulting in the renewal of Pickering's power reactor operating license to August 31, 2018.

Challenges to the value and economic merits of the Pickering continued operations were made by GEC and AMPCO, including whether the analysis was incorrect as the assessment omitted the impact of surplus generation. The Board accepts OPG's evidence that surplus baseload generation was included in the OPA's analysis.

The Board reiterates its view that the project is consistent with government direction, and that benefits (while significantly reduced from OPG's estimate) were determined by the OPA to be positive. The OPA also brought to the Board's attention the non-economic benefits of Pickering Continued Operations. For these reasons, the Board does not see the value of directing OPG to complete a detailed analysis of the net benefits of continued operation of Pickering units.

3.5 Nuclear Capital Expenditure and Rate Base

(Issues 2.1, 4.6, 4.7 and 4.8)

OPG has applied for total capital expenditures of $196.3M in 2014 and $143.9M in 2015, excluding the Darlington Refurbishment Project. The proposed capital expenditure for 2014 represents a decrease over 2013 actuals. OPG states that the decrease in 2015 is due to a reduction in the number of capital projects. OPG also seeks Board approval for nuclear in-service additions of $158.3M for 2014 and $141.7M for 2015.

OPG's historical and forecast capital expenditures for the nuclear facilities, excluding Darlington Refurbishment, are summarized in the following table.

Table 15: Nuclear Operations Capital Expenditures (excluding Darlington Refurbishment Project)

$millions	2010 Budget	2010 Actual	2011 Approved	2011 Actual	2012 Approved	2012 Actual	2013 Budget	2013 Actual	2014 Plan	2015 Plan
Darlington NGS	24.3	33.8	12.8	47.9	5.6	50.5	68.8	76.4	20.6	9.5
Pickering NGS	22.6	93.0	1.5	56.1	0.5	78.7	67.2	90.6	22.2	2.2
Nuclear Support	58.0	30.1	3.9	31.2	0.7	16.7	13.0	24.0	4.2	1.3
Total Portfolio Projects (Allocated)	104.9	156.9	18.2	135.2	6.8	145.9	149.0	191.0	47.0	13.0
Facility Projects (to be Released)	36.6	-	74.0	-	55.0	-	-	-	0.0	0.0
Portfolio Projects (Unallocated)	30.4	-	79.8	-	110.3	-	1.4	-	128.0	109.2
Total Portfolio Projects	171.9	156.9	172.0	135.2	172.1	145.9	150.4	191.0	175.0	122.2
P2/3 Isolation	8.8	5.9	-	-	-	-	-	-	0.0	0.0
Minor Fixed Assets	20.2	15.4	19.7	12.9	19.5	15.5	19.9	10.2	21.3	21.7
Total Nuclear Operations Capital	**200.9**	**178.2**	**191.7**	**148.1**	**191.6**	**161.4**	**170.3**	**201.2**	**196.3**	**143.9**
Source: Exh D2-1-2 Table 4 & Exh L -1-Staff-2 Attachment 1 Table 11										

Based on historical overestimating of capital budgets and approvals, Board staff proposed that a 10% reduction to the requested amounts would be a more reasonable level of forecast expenditure. Several parties agreed with the Board staff submission. CME observed that a historical comparison of Board approved amounts with actuals results in a difference of 20%.

OPG submitted that the analysis of historical trends is not a review of reasonableness of the test period nuclear capital project forecast.

With respect to nuclear rate base additions excluding Darlington Refurbishment, a summary of historical and forecast additions is provided below.

Table 16: Nuclear Operations In-Service Additions (excluding Darlington Refurbishment Project)

	2010		2011		2012		2013		2014	2015
$millions	Budget	Actual	Approved	Actual	Approved	Actual	Budget	Actual	Plan	Plan
Darlington NGS	43.1	31.2	32.9	32.3	90.1	52.9	89.9	183.7	43.9	7.7
Pickering NGS	103.1	166.8	4.5	27.4	17.9	41.0	53.6	97.1	48.8	12.5
Nuclear Support Divisions	25.1	35.6	67.9	30.6	12.5	22.5	17.4	30.7	6.4	0.7
Supplemental in-Service Fcst	-	-	50.5	-	47.6	-	-		37.9	99.1
Minor Fixed Assets	20.2	15.4	19.7	12.9	19.5	15.5	19.9		21.3	21.7
TOTAL	**191.5**	**249.0**	**175.5**	**103.2**	**187.6**	**131.9**	**180.8**	**311.5**	**158.3**	**141.7**
Source: Exh D2-1--3 Table 4 & Exh L-1-Staff-2 Attachment 1 table 2										

In the previous payments case, the Board expressed concern with the forecasting of nuclear in-service additions. The EB-2010-0008 decision states, “In the next proceeding, the Board will re-examine the issue of rate base additions and the accuracy of OPG’s forecasts in this area.”[43]

Board staff submitted that OPG has a recent history of over estimating in-service additions by 12% in the period 2010 to 2012, and submitted that the rate base should be adjusted to reflect a reduction of $18M and $17M from the proposed in-service amounts for 2014 and 2015 respectively. AMPCO and CME supported Board staff’s submission.

OPG argued that Board staff’s analysis was incorrect as the 2013 variance was not factored into the analysis.

Board Findings

The Board finds that OPG’s proposed capital expenditure budget for projects coming into service during the test period is reasonable. The projects are supported by business cases approved by the appropriate level of authority within OPG. The Board is providing no explicit approval in this Decision for the capital budget associated with multi-year nuclear projects (excluding the Darlington Refurbishment Project) which do not come into service during the test period. Although OPG has underspent during the three year period from 2010 – 2012 relative to its approved or budgeted capital expenditures, this is not true of 2013. The Board notes variation in the actual capital expenditures ranging from $148.1M in 2011 to $201.2 in 2013. The requested capital expenditures for 2014 and 2015 fall in the range of previous actual expenditures.

With respect to in-service additions, the Board has reviewed the data over a longer term period (2010-2013). The Board notes that the actual additions to rate base vary, with 2013 actual in-service additions significantly higher than previous years. OPG’s proposed in-service additions for the test period fall well within the range of historical actuals. The Board approves the proposed test period in-service additions for nuclear projects (excluding the Darlington Refurbishment Project) of $158.3M in 2014 and $141.7M in 2015.

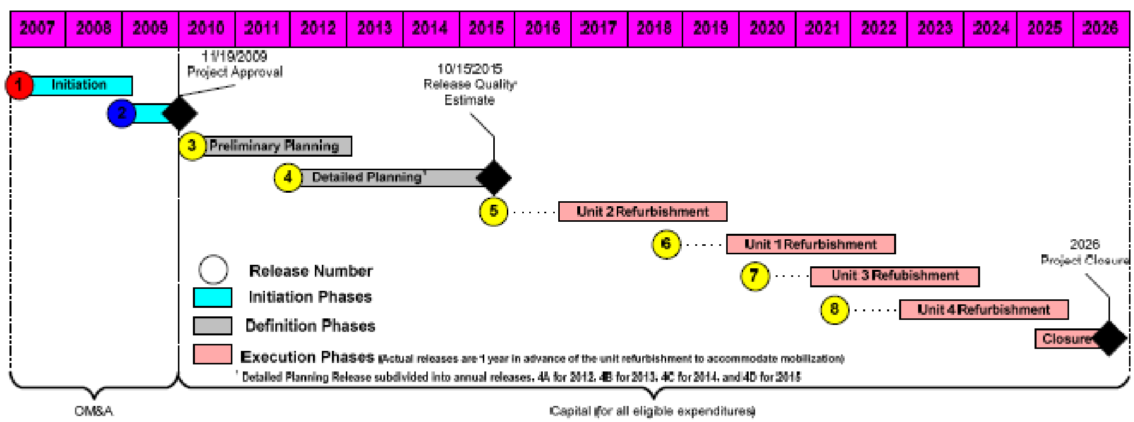
[43] Decision with Reasons, EB-2010-0008, page 59

3.6 Darlington Refurbishment Project

In February 2010, OPG announced it was proceeding with Darlington Refurbishment to extend plant life by 30 years to 2045-2050. OPG continues to have high confidence that the project will cost less than $10 billion (in terms of 2013 dollars) or $12.9 billion including capitalized interest and future escalation.

The refurbishment project phases are presented in the figure below.[44] This strategy was approved by OPG's Board of Directors in November 2013. The project is currently in the detailed planning and definition phase. A major milestone is the release quality estimate expected in October 2015, followed by refurbishment of Unit 2 in October 2016.

Figure 1: Overview of the Darlington Refurbishment Release Strategy



In the current proceeding OPG seeks:

- Approval of OM&A expenditures of $6.6M in 2014 and $18.2M in 2015.
- Approval of in-service additions to rate base of $5.0M in 2012, $104.2M in 2013, $18.7M in 2014 and $209.4M in 2015.
- A finding that proposed capital expenditures of $839.9M in 2014 and $842.5M in 2015 are reasonable.
- Recovery of capital cost portion of the Capacity Refurbishment Variance Account December 31, 2013 balance in the amount of $5.7M.
- A finding that commercial and contracting strategies are reasonable.

[44] Exh D2-2-1 Attachment 5 page 27

3.6.1 OM&A Expenditures (Issue 6.7)

Only Lake Ontario Waterkeeper ("Waterkeeper") made submissions on OM&A related to the Darlington Refurbishment Project. Waterkeeper submitted that the Board needs to ensure that adequate provision has been made for the environment, and that such a finding would fall under the Board's public interest mandate. Waterkeeper asked that the Board put two conditions on the approvals contained within this application.

First, that OPG be required to provide updates concerning the progress and actual costs of the Environmental Assessment Follow-up studies, other refurbishment project environmental monitoring studies and any adaptive management projects.

Second, Waterkeeper asked that the Board require OPG to provide detailed updates to show how its environmental oversight bodies have taken account of the environmental effects of the Darlington Refurbishment Project. Specifically, OPG should be able to demonstrate how they can prevent, mitigate and learn from environmental accidents or contingencies.

OPG argued that environmental regulatory oversight of OPG rests with the Canadian Nuclear Safety Commission, and that providing environmental assessment related filings to the Board is not required.

Board Findings

The Board approves OM&A expenditures of $6.6M in 2014 and $18.2M in 2015 for the Darlington Refurbishment Project.

The Board acknowledges that environmental regulatory oversight for the Darlington Refurbishment Project falls within the jurisdiction of the Canadian Nuclear Safety Commission. However, the Board is responsible for considering the costs that will ultimately flow through to payment amounts and will be borne by ratepayers. Accordingly, the Board will require OPG to file at its next cost of service proceeding updates of actual costs of environmental assessment follow-up studies, costs of environmental monitoring studies and costs of any adaptive management projects. The Board will impose the first condition on OPG as described by Waterkeeper. This condition relates directly to the Board's mandate to consider costs. The Board will not require OPG to provide the information contained in the second condition proposed by Waterkeeper. This information falls within the mandate of OPG's environmental regulatory authorities.

3.6.2 In-Service Additions to Rate Base (Issue 4.9)

As filed on September 27, 2013, OPG requested approval for Darlington Refurbishment Project in-service additions of $18.7M and $209.4M in 2014 and 2015 respectively.

OPG filed two updates to the Darlington Refurbishment Project evidence:

- As reported in Exhibit N1 filed on December 6, 2013, Darlington Refurbishment Project in-service additions were revised to $26.1M in 2014 and $310.0M in 2015.
- As noted in Exh D2-2-2 filed on July 2, 2014, in-service additions were revised to $67.2M in 2014 and $222.7M in 2015.

The original filing and the two updates for 2014 and 2015 in-service additions are summarized below.[45] The in-service additions are related to campus plan projects i.e. facilities and infrastructure, to support current operation, the refurbishment and operation after refurbishment. As the revenue requirement impact was not material, OPG did not propose any changes to its request for in-service amounts.

$ millions	Originally Filed Exhibit D2-2-1			As updated Exhibit N1-1-1 and D2-2-1 Attachment 5			As Updated Exhibit D2-2-2		
	Final In-Service Date	2014	2015	Final In-Service Date	2014	2015	Final In-Service Date	2014	2015
Darlington OSB Refurbishment	Jul-15	-	29.7	Oct-15	-	37.7	Aug-15	-	45.1
D2O Storage Facility	Apr-15	-	83.5	Oct-15	-	94.2	Jan-17	15.5	1.0
DN Auxiliary Heating System	Mar-15	-	36.3	Apr-15	-	43.5	Mar-15	-	75.3
Water & Sewer	Nov-14	12.2	-	Nov-13	-	-	Nov-15	22.6	6.6
Elec Power Distribution System	Apr-15	4.4	6.2	Jun-14	10.0	-	Nov-14	12.0	-
Darlington Energy Complex	Jul-13	-	-	Jul-14	6.0	-	Jul-15	2.1	4.1
RFR Island Support Annex	Apr-16	-	-	May-15	-	25.4	Apr-16	-	-
Other Campus Plan projects	various	-	-	various	10.2	-	various	15.1	7.6
Safety Improvement Opportunities	various	-	42.7	various	-	90.5	various	-	83.0
Other Station Modifications	various	2.1	11.1	various	-	18.7	various	-	-
Total		**18.7**	**209.4**		**26.1**	**309.9**		**67.2**	**222.7**

[45] Exh D2-2-2 page 6 Table 1

Environmental Defence submitted that the in-service additions are not appropriate as OPG has not established that the assets are required "but for" the Darlington Refurbishment. The assets will only provide benefit to ratepayers as part of the overall Darlington Refurbishment Project and should not be included in rate base until the refurbished units are in-service. One of the reasons that the Board rejected construction work-in-progress for the Darlington Refurbishment Project in the EB-2010-0008 proceeding was that it was still in the definition phase. Environmental Defence observed that the project is still in the definition phase.

Several parties sought clarification from OPG at the technical conference and oral hearing about its request with respect to Darlington Refurbishment in-service additions. Parties sought to understand the extent of project completion in the test period. In particular, the evidence filed in July 2014 indicated that the D2O (heavy water) storage facility and Auxiliary Heating System project were delayed and/or projected to be over-budget.

OPG indicated that costs and timelines for the D2O storage facility have changed as the scope of work was not well understood initially and there were new seismic requirements from the Canadian Nuclear Safety Commission. Similarly, OPG indicated there were scope changes arising from the contractor's original underestimation of scope complexity for the Auxiliary Heating System project.

Based on its review of the evidence, which included reports of consultants retained by OPG to provide external independent oversight of the Darlington Refurbishment, GEC submitted that OPG has not demonstrated prudence in expenditure decisions, project planning or expenditure management. Even though some of the projects may be in-service, similar to Environmental Defence, GEC submitted that the projects are not required but for Darlington Refurbishment. Both Environmental Defence and GEC referred to an Alberta Court of Appeal decision that found that the used and useful principle requires that the facilities be required, not merely in use. However, in reply, OPG argued that the Alberta Court of Appeal decision was related to a provision of an Alberta statute that is not established law in Ontario.

Board staff and several other parties expressed some concern with OPG's proposal to retain its original in-service addition request despite updated information about the status of individual campus plan projects. The parties proposed revisions to OPG's request.

PWU submitted that OPG's proposal could be problematic for the Board to apply the principle of used and useful and to make a determination of what amounts should be added to rate base. The PWU's preference is for the Board to make a determination based on the updated in-service addition amounts.

In SEC's view, the rate base additions should be limited to $34.6M in 2014 and $6.6M in 2015 related to the water and sewer project and the electrical distribution project. There is insufficient evidence for some of the other projects and the remaining proposed additions should not be approved until the refurbished units are running. For projects for which there is insufficient evidence, SEC proposed additions to the Capacity Refurbishment Variance Account and review in a future application when supporting evidence was available. This matter is also noted in the Deferral and Variance Account section of this Decision.

Board staff recommended that the Board accept the amounts that OPG seeks to close to rate base, but that the approval should not be considered a finding of prudence for the D2O storage facility. CME agreed with staff, but submitted that a 10-20% reduction was appropriate to redress management failures identified by OPG's external consultant. VECC submitted that until the cost of managerial errors and remedial expenditures was independently determined, no additions to rate base should be approved.

It is OPG's view that all the campus plan projects will be used or useful when placed in-service and useful to the station generally, not wholly related to Darlington Refurbishment. There is sufficient evidence for all the projects and explanation for scope changes that led to cost increases for projects.

Board Findings

The Board will approve OPG's proposed test period in-service additions of $18.7M in 2014 and $209.4M in 2015.

Proposed in-service amounts represent assets that will come into service in the test period. OPG has sought to include some test period amounts which represent part of the larger Darlington Refurbishment Project. OPG submitted that the campus plan projects related to the proposed in-service additions are not wholly related to the Darlington Refurbishment Project, but are useful to the on-going operations of

Darlington as well. The Board has considered this evidence and agrees that the campus plan projects described are useful to the on-going operations of Darlington. The Board finds OPG's proposal to be reasonable in the specific circumstances in this case.

While Board staff agreed with the proposed amounts to be added to rate base for 2014 and 2015, they cautioned that the D2O project will not be fully complete until January 2017. Board staff agreed that a portion of the costs should be included in rate base but took the position that the Board's approval should not be considered to be a finding of prudence for the entire D2O project. The Board agrees. OPG has confirmed its understanding that the inclusion of test period amounts related to a portion of a project does not mean that the entire project is being accepted by the Board. A prudence review should take place when the D2O project is completed and fully in-service which it is expected will be OPG's next payment case.

The Board also considered the argument put forward by CME that a reduction of between 10-20% be made to the in-service additions related to the D2O project and the Auxiliary Heating System project. The Board accepts OPG's evidence that the increased costs represent more accurate project costs and therefore the Board will not require a reduction.

3.6.3 Test Period Capital Additions (Issue 4.10)

As originally filed in September 2013, Darlington Refurbishment Project capital expenditure was forecast to be $837.4M in 2014 and $631.8M in 2015. While the project is in the detailed planning and definition phase, facility and infrastructure projects to support or extend Darlington station life have commenced.

OPG updated its forecast of capital expenditure twice during the proceeding resulting in an increase of the proposed capital expenditures to $839.9M in 2014 and $842.5M in 2015.

Both Environmental Defence and GEC argued that the levelized unit energy cost analysis for Darlington Refurbishment is flawed and submitted that the capital expenditure request is not reasonable. Criticisms included consideration of externalities and limited costing of alternatives.

Board staff recommended that the Board not make a finding on the reasonableness of proposed capital expenditures as most of the projects would not go into service in the test period. Board staff indicated that the evidence was not complete regarding the amount comprising the updated capital expenditures for 2014 and 2015. OPG did not clarify or produce a list of projects in its reply argument. CME agreed with Board staff, noting that there was significant uncertainty around the estimates for projects making up the Darlington Refurbishment Project.

SEC also agreed with Board staff, noting that although there was a lot of evidence filed, it was not sufficient to allow the Board to make a binding determination on test period capital for Darlington Refurbishment. SEC noted that the independent reports on the campus plan projects were critical of the cost overruns, and submitted that the $1.7 billion proposal was unlikely to be correct and unlikely to be prudently incurred. OPG argued that the overall impact of the campus plan project overruns was minimal and that OPG has been responsive to the independent oversight of the project.

Board Findings

The Board indicated in an earlier ruling in this proceeding that it will not consider, as a threshold issue, whether the Darlington Refurbishment Project should proceed.[46] The Board maintains that the decision to refurbish Darlington is a decision that has been made by the provincial government and forms a key component of the Long-Term Energy Plan. As such, at this time the Board needs only to focus on the test period capital expenditures.

The Board notes that the majority of the capital expenditures proposed will not be added to rate base within the test period. The Board will not determine whether the amounts are reasonable or not, deferring that decision until OPG seeks to add these capital expenditures to rate base.

[46] Decision and Order on Issues List and Procedural Order No. 3, February 19, 2014, page 10, "…the examination of cost effectiveness of capital expenditure in the test period is within scope in this proceeding. Parties are reminded that the Board's jurisdiction is the setting of payment amounts and not the management of OPG's activities or the selection of generation options."

3.6.4 Commercial and Contracting Strategies (Issue 4.11)

OPG sought the Board's approval of its commercial and contracting strategies for the Darlington Refurbishment Project. OPG is utilizing a "multi-prime contractor model" where there is more than one prime contractor and the owner has a separate contract with each prime contractor. As the integrator between contractors, OPG retains project management responsibility and design authority. OPG has engaged external technical and project management experts to assist with this project management. The benefits of this model are that OPG retains control over the project, including deliverables, costs and schedules. OPG filed an Assessment of its Commercial Strategies prepared by Concentric Energy Advisors, dated September 2013.[47]

Many of the contracts will be target priced contracts. Under this model contractors receive incentives to meet cost and timeline targets. If the targets are missed, contractors will receive less incentive, but will receive payment for reasonably incurred expenses.

The strategies for the five major work packages (Re-tube and Feeder Replacement, Turbines and Generators, Fuel Handling, Steam Generators, and Balance of Plant) were reviewed by Concentric Energy Advisors. The Concentric reports filed with the application concluded that the strategies were reasonable and prudent.

In support of its application, OPG presented Mr. John Reed, a principal from Concentric Energy Advisors as a witness in the oral hearing. Mr. Reed stated in his evidence that for each of the major work packages for which Concentric offered an opinion, Concentric concluded that the company's conduct was within a range of "reasonable behaviour" and did represent "acceptable risk."[48]

It was not clear to Board staff or the parties what OPG was seeking from the Board related to commercial and contracting strategies or why such a finding was necessary. Board staff submitted that any decision on this matter would be a form of project management and that no specific approval should be provided.

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[47] Exh D2-2-1 Attachment 7
[48] Tr Vol 13 pages 148-149

In SEC and CME's view, OPG's request is an attempt to "buy insurance" and to insulate OPG from commercial and contractual risks and from criticism in future proceedings. Approval of contracting and commercial strategies is neither necessary nor desirable.

OPG argued that a finding of reasonableness by the Board does not eliminate the need for future prudence review, but will enable the review to be assessed in the appropriate context.

Both GEC and Environmental Defence submitted that OPG's commercial and contracting strategies are contrary to the Long-Term Energy Plan as they expose ratepayers to too much risk. The evidence suggests that OPG bears the primary risk for overruns with respect to 93% of the project costs.[49] Environmental Defence was critical of cost overruns on previous projects including most recently the Niagara Tunnel Project and the Darlington Refurbishment campus plan projects. Environmental Defence submitted that there is no ratepayer protection for replacement power associated with project delays.

OPG clarified that the 93% of project costs includes OPG internal costs, and that only 27% of the $10 billion estimate is on a target price basis.[50]

GEC submitted that the project risk will not be monetized until the release quality estimate is complete; therefore, it is premature to structure the commercial arrangements and contract strategy. While OPG has stated that allocating more risk to contractors would have significant cost, GEC submitted that the commercial and contracting strategy should be informed by an understanding of the risks. Optimal allocation of those risks will enable compliance with the principles of the Long-Term Energy Plan.

OPG argued that GEC and Environmental Defence have taken a narrow view of risk. There is a multi-faceted risk minimization approach including OPG's retention of project management responsibility, a significant testing effort in advance of the release quality estimate and continuous internal and external oversight. While the parties claim that a fixed price turnkey arrangement is the only means to minimize risk, this is not possible for a mega project like Darlington Refurbishment as there are risks that contractors would not be willing to take on.

[49] Tr Vol 15 page 56
[50] Reply Argument page 107

Board Findings

The Board will not make a finding that the commercial and contracting strategies used by OPG in the Darlington Refurbishment Project are reasonable.

OPG proposed this issue in the draft issues list filed with the application. However, during the oral phase of the hearing it was unclear how a finding of reasonableness would be defined and why such an approval by the Board was necessary. On the last day of the hearing, in response to the Board's questioning as to what the Board would be approving if it determined that the contracting strategy was reasonable, OPG clarified that the Board would not be approving the contracts, it would not be approving the conduct of the contract negotiations, and it would not be approving the procurement process. The Board would not be approving any prices established through the contracting process, nor would the Board be approving the selection of the winning proponent(s).[51]

In OPG's view, the Board would be making a finding of reasonableness in respect of the guiding principles forming the contracting strategy which OPG described as including;

1. A multi-prime contractor model in which OPG retains overall project management and design authority responsibility;
2. The division of the work into 5 work packages;
3. A model where the prime contractor is responsible for some combination of engineering, procurement and construction within each of the 5 work packages; and
4. The means by which risk would be allocated.[52]

The Board will not make the finding requested by OPG for two reasons.

First, the application before the Board is an application for payment amounts for the years 2014 and 2015. The Board is of the view that the commercial and contracting strategies approval sought by OPG extends beyond a determination of those payment amounts. While there may be a tangential link between a contracting strategy and the rates requested, the Board finds that the link in this case is not direct enough. The Board agrees with Board staff that the request, as defined by OPG, is tantamount to an

[51] Tr Vol 16 page 5
[52] Tr Vol 16 page 4 (all subject to available contract options in the market place)

approval of project management which is not the role of the Board. Project Management and project execution are the responsibility of OPG.

If the Board were to make a finding on the reasonableness of the commercial and contracting strategies, the onus would be on OPG as the applicant to provide the Board with sufficient evidence to satisfy the Board that the commercial and contracting strategies are reasonable. Given the guiding principles articulated by OPG, the Board would have required far more evidence than was presented to reach those conclusions. On July 2, 2014, OPG filed reports that independently assessed the execution of some infrastructure projects related to the refurbishment. The reports prepared by Burns & McDonnell and Modus Strategic Solutions were critical of project execution and raised concerns including the impact on Darlington Refurbishment schedule and costs. In fact, the Board had to take a two-week recess from the proceeding to provide parties with the opportunity to review and analyze the reports filed on July 2, 2014.

The Board, in order to make any determination, must be satisfied that a thorough and complete hearing of this issue has taken place. The Board is not satisfied that this has occurred.

3.6.5 Darlington Refurbishment and Long-Term Energy Plan (Issue 4.12)

In Board staff's view, the Darlington Refurbishment is aligned with the Long-Term Energy Plan, however, the other parties submitted that it was premature to make a finding. OPG observed that the province has very clearly indicated that Darlington Refurbishment is a key part of the Long-Term Energy Plan and that no concerns have been raised with respect to compliance.

The Board will not opine on whether OPG's nuclear refurbishment process for Darlington aligns with the Government of Ontario's Long-Term Energy Plan. The Board considers this review to be outside of its mandate. A key component of the principles outlined in the Long-Term Energy Plan is the appropriate allocation of risk as it relates to nuclear refurbishment. The Board is of the view that for the reasons previously stated, the amount of evidence related to appropriate risk allocation would be insufficient for the Board to reach such a finding.

3.7 Nuclear Other Revenue

(Issue 7.2)

OPG receives revenue from non-energy businesses and that revenue is applied as an offset to the nuclear revenue requirement. These businesses are heavy water services, isotope sales and inspection and maintenance services. The nuclear facilities also provide ancillary services as described in the Hydroelectric Other Revenue section of this Decision. Variances between forecast and actual ancillary services revenue are recorded in the Ancillary Service Net Revenue Variance Account – Nuclear.

The table below sets out the actual and forecast levels for other revenue.

Table 17: Nuclear Other Revenue

$million	2010 Actual	2011 Actual	2012 Actual	2013 Budget	2013 Actual	2014 Plan	2015 Plan
Heavy Water Sales and Processing	26.7	80.9	55.1	18.9	34.8	26.3	20.4
Isotope Sales	10.1	4.8	11.5	11.1	7.0	11.6	11.9
Inspection & Maintenance Services	36.0	7.1	4.1	0.0	0.0	0.0	0.0
Helium 3 Sales	0.0	0.0	0.0	0.0	0.0	0.0	4.0
Costs	-31.5	-10.7	-8.7	-7.2	-5.9	-6.8	-7.8
Sub-total	41.3	82.1	62.0	22.8	35.9	31.1	28.5
Ancillary Services	2.6	2.4	1.8	1.9	1.7	1.9	1.9
Third Party Training	0.8	0.6	0.1	0.1	0.0	0.1	0.1
Total	**44.7**	**85.1**	**63.9**	**24.8**	**37.6**	**33.1**	**30.5**
Source: Exh G2-1-1 Table 1, Exh L-1-Staff-2 Table 35							

Board staff observed that OPG regarded its 2013 budget as "a return to more normal conditions for sales of heavy water, heavy water detritiation services and isotope sales."[53] However, the 2013 actual total other revenue was $12.8M or 51% higher than 2013 budget. OPG subsequently described the lower test period forecast as "a return to a more normal level of revenues for heavy water sales and processing."[54] Board staff submitted that the Board should consider the 2013 actual nuclear other revenue as the normal level for the test period and approve $37.6M for each of 2014 and 2015. OPG argued that heavy water sales and processing are subject to services provided to

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[53] Exh G2-1-2
[54] Argument-in-Chief page 122

external parties and maintenance of the tritium removal facility and that it is not appropriate to consider just historical levels.

AMPCO submitted that OPG's 2014 and 2015 forecasts for Heavy Water Sales and processing are too low based on historical actuals, and proposed that a 4 year average be used to forecast the test period. LPMA proposed that a 3 year average be used. OPG argued that there is no pent up demand for heavy water sales and processing. The 2011 and 2012 revenues were related to the restart of Bruce and Point Lepreau reactors. OPG submitted that forecasting is more complex than relying on the past.

Board Findings

The Board accepts OPG's arguments that higher historic revenues in 2011 and 2012 from Nuclear Other Revenues may have been impacted by one-time events such as the increased sales to Bruce Power and Point Lepreau and may not be indicative of future revenues in the test period. The Board finds however that OPG has not substantiated its forecast decline for Nuclear Other Revenues. As a result, the Board finds the 2013 actual Nuclear Other Revenues of $37.6M to be appropriate for 2014 and for 2015.

4 CORPORATE COSTS

4.1 Compensation

(Issue 6.8)

Compensation is one of OPG's largest expenses. Compensation costs include salaries, wages, current pension expenses and other post-employment benefit ("OPEB") expenses and are expected to be $1,604.2M in 2014 and $1,618.1M in 2015; for a total of $3,222.3M in the test period. This amount is approximately 35% of OPG's annualized requested revenue requirement of $9.28 billion. There is no single "line item" for OPG's compensation costs. These costs are spread throughout various OM&A budgets and to some minor extent, are included in capital budgets.

The majority of OPG's compensation costs relate to its unionized work force in the PWU and the Society. Approximately 86% of compensation costs in 2014 are for employees represented by these two unions. OPG is required to collectively bargain with the PWU and the Society. The current collective agreement for the PWU covers the period April 1, 2012 to March 31, 2015. The Society collective agreement covers the period January 1, 2013 to December 31, 2015. OPG's position is that the requirement to bargain collectively with its unions places restrictions on its ability to control its compensation costs. The 2013-2015 business plan assumes no PWU increase for the period beginning April 1, 2015 other than a one per cent increase for step progression. For the Society the 2013-2015 business plan assumes a zero per cent increase over the test period, again with a one per cent increase for step progression.[55]

Broadly speaking, OPG's total compensation costs are the function of two things: the number of employees, and the amount that employees are paid, including pension expenses and benefits. Efforts to control costs can focus on either of these elements, or both.

Many parties argued that OPG's compensation costs are excessive, and that the Board should disallow recovery for a portion of the costs. CME argued that the evidence was clear that OPG is both overstaffed, and that its compensation levels significantly exceed industry benchmarks. It proposed disallowances of $146M in 2014 and $144M in 2015. SEC argued that although OPG had made significant progress in addressing its

[55] Argument-in-Chief page 4

overstaffing issues, its compensation levels remained excessive and that there were serious concerns regarding a lack of management oversight and accountability. SEC recommended disallowances of $100M in each of the test years. Both LPMA and CCC argued for the same reductions, on largely the same basis. Staff argued for OM&A reductions totaling $170M over 2 years, of which the majority would be attributable to compensation.

OPG submits that its compensation costs should be accepted by the Board as filed. It argued that there is no evidence that OPG could have reached a more favourable result through its collective bargaining and arbitration processes. OPG submits that it achieved very positive results in its most recent collective agreements: a "net zero" result for the PWU, and a modest wage increase for the Society, which was imposed by an arbitrator. OPG argues that it is legally required to collectively bargain within the confines of the Ontario *Labour Relations Act*, and that it achieved the best results possible under that framework. It relies on the evidence[56] of Dr. Richard Chaykowski, who testified that general compensation benchmarking studies are of limited value in a collective bargaining environment. The PWU and Society made similar arguments.

Board Findings

The Board has determined that it will disallow $100M from OPG's proposed total OM&A expenses in each of 2014 and 2015. This OM&A reduction relates directly to what the Board finds to be excessive compensation, and it applies to both the nuclear and hydroelectric businesses.

OPG's high total compensation costs have been a matter of concern for the Board for many years. In OPG's first payments proceeding (EB-2007-0905) the Board disallowed $35M in OM&A costs related to poor performance at Pickering A. The Board also found that OPG had not been responsive to benchmarking recommendations. The Board ordered OPG to conduct additional benchmarking studies for its next application.

The Board revisited compensation issues in OPG's second payments proceeding (EB-2010-0008). In that decision, the Board stated that it was "of the view that OPG has opportunities to reduce the overall number of employees further as a means of controlling total costs and enhancing productivity."[57] The Board also found that, "the

[56] Exh F4-3-1 Attachment 1
[57] Decision with Reasons, EB-2010-0008, page 85

[compensation] analysis provides sufficient evidence to conclude that for a significant proportion of OPG's staff the compensation is excessive based on market comparisons." The Board disallowed $145M in nuclear compensation costs over the two year test period. The Board further directed OPG to retain an expert to conduct benchmarking studies on its nuclear staffing and on its overall compensation levels.

Since the last payments case, OPG undertook a number of measures in an attempt to control its overall compensation costs. In 2011, OPG introduced a Business Transformation initiative to reduce staff levels in response to expected decreases in capacity and energy production in the coming years. The Business Transformation initiative has resulted in a steady decline in the number of employees in both the regulated and unregulated sides of its business. From 2011 to 2015, OPG will reduce its staff numbers by approximately 1,300 in its regulated businesses, which is more than 10% of its complement. OPG estimates that these staff reductions result in savings of approximately $550M – i.e. absent the Business Transformation initiative OPG would have incurred $550M more in costs for the period 2011 to 2015.[58]

Despite OPG's reduction of 10% of its workforce in the regulated business, total compensation amounts are forecast to go up over the test period: from $1,581M in 2010 to a forecast of $1,618.1M in 2015. This is due to higher average compensation per employee. The large average increases are driven in part by increased pension costs resulting from changes to the discount rate.[59]

The Board is not the only body that has expressed concern regarding OPG's compensation levels. On December 10, 2013, the Auditor General of Ontario released its annual report which included a review of OPG human resources polices over a 10 year period. The Auditor General noted that "OPG's generous compensation and benefits negatively impact electricity costs."[60] The Auditor General stated that despite the Business Transformation process, there are still many areas relating to compensation and benefits practices that need further improvement.[61]

[58] Exh A4-1-1
[59] Tr Vol 8 page 40 - MS. LADAK: Yes, in terms of total compensation, wages are going down as a result of headcount reductions. But as a result of pension increases, due to, largely, discount rate changes, total compensation is going up.
[60] News Release, Office of the Auditor General of Ontario, December 10, 2013
[61] Exh KT2.4, Annual Report of the Auditor General, page 153

There is significant evidence on the record that OPG's overall compensation costs are higher than they should be. This evidence includes the Auditor General's annual report (the details of which were reviewed with OPG in the hearing), the Goodnight Consulting report and the AON Hewitt report. The nuclear benchmarking reports based on the ScottMadden methodology further details OPG's poor overall cost effectiveness. These reports are discussed below. The Board observes a number of factors that drive these excessive compensation costs: too many staff and management, too much compensation (including pensions) for many of OPG's unionized employees, and a lack of management oversight with respect to performance management and overtime.

4.1.1 Staffing Levels

The following table summarizes historic and test period staffing levels.

Table 18: Staffing Levels

Full Time Equivalent ("FTE")	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Plan	2015 Plan
Nuclear	8,445.4	8,215.1	6,761.8	6,554.2	6,579.7	6,519.9
Previously Regulated Hydroelectric	359.7	369.4	343.8	321.5	343.1	340.9
Newly Regulated Hydroelectric	584.3	617.4	600.9	584.0	599.5	582.2
Allocated Corporate Support	1,091.4	1,072.4	2,299.0	2,142.7	2,043.8	1,952.6
TOTAL	**10,480.8**	**10,274.3**	**10,005.5**	**9,602.4**	**9,566.1**	**9,395.6**
Management	1,101.7	1,099.2	1,095.6	1,091.0	1,101.0	1,076.3
Society	3,269.0	3,254.6	3,112.6	2,909.2	3,043.3	2,965.6
PWU	6,012.9	5,840.7	5,711.0	5,542.0	5,371.7	5,300.3
EPSCA	97.2	79.8	86.3	60.2	50.1	53.4
TOTAL	**10,480.8**	**10,274.3**	**10,005.5**	**9,602.4**	**9,566.1**	**9,395.6**

Source: J9.7, EPSCA - Electrical Power Systems Construction Association

The area where OPG has made the most progress is with respect to staffing levels, as demonstrated by the staff reductions they have achieved through the Business Transformation initiative. At the Board's direction, OPG retained Goodnight Consulting Inc. ("Goodnight") to conduct a staffing benchmarking study for the nuclear business specifically.[62] Goodnight compared OPG's nuclear staffing levels against the 16 largest

[62] Exh F5-1-1

nuclear stations in the United States. Goodnight made certain adjustments to exclude activities specific to CANDU technology (which is not used in the United States), and to account for OPG's shorter work week. Goodnight was able to find suitable comparators for 5,574 positions. Goodnight was not able to benchmark 2,101 positions, mostly CANDU specific, due to lack of comparable benchmarks. Of the support functions, only corporate support dedicated to the nuclear business was considered.[63]

Goodnight concluded that, for the positions surveyed, OPG was 17% (866 positions) above the comparable benchmark as of July 2011. By February 2013 the situation had measurably improved: 7.6% (394 positions) over the benchmark. An update as of March 2014 showed additional improvement: 4.7% (244 positions) over the benchmark. By the end of the test period, OPG will likely be close to the benchmark level for the positions surveyed.

Although the Board recognizes that OPG has made progress in reducing its staffing numbers to approach industry standard levels, the Board finds that OPG remains overstaffed in the test period.

Several parties critiqued the Goodnight study, arguing that it was faulty because it did not include a large number of staff positions (and thereby likely underestimated the amount of overstaffing). They also argued that it failed to sufficiently recognize the unique features of OPG's CANDU technology (and thereby did not present a proper comparison for benchmarking). The Board is aware of the limitations of benchmarking, and recognizes that the Goodnight study cannot be expected to provide a precise "number" by which OPG is over (or under) staffed. The Board is satisfied, however, that Goodnight's methodology was sound and that its analysis is directionally correct. The Board finds that OPG is still moderately overstaffed with respect to the positions surveyed by Goodnight in the test period.

Several parties further noted that, although total employee numbers are down significantly, the number of management staff has barely moved: 1,101.7 in 2010 versus 1,101 and 1,076.3 forecast for 2014 and 2015 respectively. As a result, the percentage of employees that are managers has increased from approximately 10.5% in 2010 to 11.5% in 2015. The number of senior management and executive positions, the highest paid managers, has in fact increased significantly in recent years. The Report of the Auditor General revealed that from 2005-2012, the number of executives

[63] Exh F5-1-1 page 16

increased 74% and that the number of senior managers increased by 47%.[64] Many vice presidents and directors (40 as of 2012) do not have specific job titles or job descriptions. OPG stated that the duties and responsibilities of these vice presidents and directors would be set by their direct supervisors, but that there was no document describing what their job was.[65] OPG further stated that some of the increases in the number of senior management related to Business Transformation (5 directors) and the Darlington Refurbishment Project (13 directors).[66]

The Board finds that OPG has not sufficiently justified the number of its management positions. Business Transformation will result in the reduction of 1,300 positions for OPG's regulated business by the end of 2015, but the number of management positions is essentially unchanged. Although the Board accepts that there is not a perfect straight line correlation between decreases in non-management headcount and management headcount, the Board would expect a level of corresponding reduction for management positions. OPG submitted that increases in managers were necessary for Business Transformation and the Darlington Refurbishment Project. The Board finds that required increases in management associated with these incremental activities, are not sufficient to justify the total complement of management positions.

The costs related to excessive numbers of managers are significant. Had management positions been reduced in proportion to the reduction in overall staffing numbers, test period compensation would be lower. OPG's witness also confirmed that the Auditor General's report indicated there was an increase in senior management positions without formal job descriptions.[67] The Board finds this unacceptable. Management positions generally have the highest salary, pension and benefit costs. Basic controls must be utilized to justify each position on a needs basis and approvals must be documented. There is a cost associated with each position, and the needs and benefits must be clearly understood to justify the cost.

4.1.2 Compensation Per Employee

OPG's compensation package includes base salary, incentives, pensions and benefits. OPG's forecast average compensation per employee for 2015 is $205,914 for

[64] Exh KT2.4, Annual Report of the Auditor General, page 159
[65] Tr Vol 8 pages 106-107
[66] Undertakings J9.1 and J9.2
[67] Exh KT2.4, Annual Report of the Auditor General, page 159

Management, $176,508 for Society employees, and $163,458 for PWU employees.[68] This represents a significant increase in average compensation since 2010: 1.82% for Management, 10.35% for Society employees, and 19.73% for PWU employees. OPG stated that it is required to collectively bargain with its unionized employees, which places restrictions on its ability to reduce compensation levels and, to a lesser extent, staffing levels. OPG has more flexibility with respect to management compensation.[69]

The Auditor General's report raised many concerns regarding OPG's compensation levels and practices, many of which were reviewed through the course of the hearing. Amongst other things, the Auditor General expressed concern over salary levels at OPG generally, and noted that for many positions at OPG, the average earnings at OPG exceeded the maximum potential earnings for the comparable position in the Ontario public service generally. The Auditor General views the public service as an appropriate general comparator for OPG.

The Board directed OPG to file a comprehensive compensation benchmarking study as part of this proceeding. OPG retained AON Hewitt to prepare this report (the "AON Report"). The AON Report was prepared in late 2011, and updated in 2013. As such it does not include increases in the average compensation for OPG's unionized workers since 2013 (nor any changes at the comparator companies). It covers salary benchmarking for the regulated business (both nuclear and hydroelectric). The AON Report has a section on total cash compensation (which excludes pensions), and a separate section for pensions.

Total Cash Compensation

With respect to total cash compensation, AON considered three comparator groups: Group 1 (power generation, electric utilities nuclear R&D), Group 2 (nuclear power generation and electric utilities), and Group 3 (general industry). The table below summarizes the results for total cash compensation (base salary and short term incentive). It does not include compensation costs related to pensions.

[68] Undertaking J9.7 Attachment 1
[69] Tr Vol 8 page 46

Table 19
Total Cash Compensation
%Differential vs 50th Percentile

%	Group 1	Group 2	Group 3
PWU	20.5	19.1	29.4
Society	-2.9	-3.8	23.3
Management	3.0	-3.4	20.9
	All job families	Admin, Engineering, Environment, Finance, Maintenance, Operations	Admin, Finance, IT, HR, Corporate Services

The AON Report concluded that the PWU is compensated at significantly higher than the 50th percentile for all three groups, whereas the Society and OPG management are compensated at close to the 50th percentile for Groups 1 and 2, and well above the 50th percentile for Group 3. The findings of the AON Report are consistent with evidence filed with the Board in previous proceedings, and OPG stated that it was not surprised by the results of the survey.[70] If PWU salaries were at the 50th percentile, OPG estimates its costs would have been reduced by $96M in 2014 and $94M in 2015.[71]

OPG's position on the AON Report (which was broadly supported by the Society and the PWU) is that although the information is interesting, it does not assist OPG in achieving better results through the collective bargaining process.

OPG presented evidence from Dr. Chaykowski to support its position. Dr. Chaykowski testified that unions typically have a great deal of negotiating power because if negotiations fail they will end up in binding arbitration. Dr. Chaykowski indicated that arbitration decisions are usually favourable to unions. Although arbitrators are supposed to take into account the employer's ability to pay, in Dr. Chaykowski's opinion they usually do not.[72] Arbitrators typically use "patterning" to set salary levels, whereby they compare the situation before them with recent agreements obtained by similar unions in similar industries. Dr. Chaykowski stated that the best comparators for OPG

[70] Tr Vol 8 pages 73-75.
[71] Undertaking J9.11 - This analysis appears to relate to Group 1, as opposed to Group 2. However, the Group 1 and Group 2 placement of the PWU are very similar (20.5% above median for Group 1 and 19.2% above median for Group 2.
[72] Tr Vol 8 page 156.

were Bruce Power and Hydro One, although he conceded different arbitrators might use different (though broadly similar) comparators.[73]

Dr. Chaykowski's evidence highlighted many of the challenges OPG faces in controlling costs in a unionized environment. He also stated that OPG wage settlements generally had been favourable when compared to what he viewed as the appropriate comparators.[74] However, pursuant to the terms of his retainer with OPG, Dr. Chaykowski was not asked to provide an opinion on the specific results achieved by OPG for its current collective agreements. Dr. Chaykowski was also not asked to provide an opinion on the appropriateness of OPG's overall compensation costs.[75]

OPG relies on Dr. Chaykowski's evidence to submit that it could not have achieved better results in its collective bargaining efforts. OPG states that no party has been able to demonstrate what better alternatives were reasonably available to it.

The Board does not accept that the costs arising from OPG's collective agreements – in particular the agreement with the PWU – are reasonable. The compensation package for PWU employees increased from 2010 to 2015 by 19.73%, almost double the 10.35% for the Society over the same time period.

The AON Report demonstrates that OPG compensates the PWU significantly in excess of the industry benchmark. The Board finds that Group 2 is the most appropriate comparator for OPG. Group 2 is a small cohort of nuclear related comparators: Atomic Energy of Canada Limited, Bruce Power, Candu Energy Inc., Hydro Quebec, and New Brunswick Power. All are unionized and have or had, in the case of Hydro Quebec nuclear operations. Three of them, including Bruce Power, which is in fact the comparator OPG prefers, are in Ontario. On average, these companies were able to achieve significantly better results than OPG through their compensation management and collective bargaining efforts with respect to PWU equivalent positions. The Board has no specific information as to how these results were achieved, but the Board does have sufficient evidence to conclude that these similar companies with comparable positions achieved superior results. OPG accepted that, as the Board is not involved in any of its collective bargaining activities, it can only judge the reasonableness of the outcome by examining the final results.

[73] Tr Vol 8 pages 54-56
[74] Exh F4-3-1 Attachment 1
[75] Tr Vol 8 pages 59-60

The Board was assisted by the analysis provided in the AON Report. The Board directs OPG to file a similar, independent, comprehensive compensation study that compares OPG compensation with broadly comparable organizations in the next cost of service application. The study should cover a significant proportion of OPG positions.

The Board does not accept OPG's argument that it should only be compared against successor companies to Ontario Hydro, in particular Bruce Power. OPG provided evidence comparing it with some of the other successor companies to Ontario Hydro, and argued that it had done well in comparison. Even to the extent that these were the only suitable comparators (an idea the Board rejects), the Board is not satisfied with the quality of the comparison conducted by OPG.

OPG provided two comparisons: a comparison of 2013 wage levels between OPG and Bruce Power for certain positions, and a general wage increase comparison between OPG and six Ontario Hydro successor companies from 2001-2012. All of the analysis was conducted by OPG.

For the wage comparison between Bruce Power and OPG, only 12 positions are compared. The positions were selected by OPG. The wage comparison does not include pensions or OPEBs, which are a significant component of OPG's compensation package. It compares only the top band in each category, and does not take into account the number of employees that might be in that band, or in any other band. In addition, the Auditor General discovered that approximately 1,200 unionized staff at OPG were in fact paid more than the maximum amount set out in the salary bands. The comparison presented by OPG does not mention this, and absent the Auditor General's report the Board in all likelihood would not have had this information.[76]

OPG conceded that different comparisons were possible, and that different companies might choose to present the data in different ways. For example, Hydro One had presented a comparison in a recent application which indicated that it had achieved favourable compensation results when compared to OPG.[77] The Board prefers the evidence of an expert third party to the less rigorous analysis conducted by OPG.

[76] When questioned on this topic, OPG responded by undertaking that the correct number was now 972, not 1,200, and that if those 972 employees (who had higher salary on account of grandfathering) were limited by the maximums in the current salary bands the impact would result in annual savings of $5.6M – Undertaking J8.1.
[77] Tr Vol 8 pages 81-85

Pension Costs

Pension costs are a major driver of total compensation costs. OPG proposes to recover $471.3M in 2014 and $405.3M in 2015 for pensions, excluding tax impacts. These amounts include the current service costs under compensation, as well as the pension component of centrally held costs.

OPG's pension plan is very generous. The AON Report benchmarked the employer paid value of OPG's pension versus the comparator group. It concluded that OPG's pensions and benefits are significantly more generous than those of its comparators. The value of OPG's pensions as a percentage of base pay was approximately 33% higher than that of the comparator group. The value of OPG's life insurance benefits and medical and dental benefits were also significantly higher than those of its comparators.[78] These pension amounts are in addition to the total cash compensation analysis referenced above in Table 19 which shows the differential to the 50th percentile.

The OPG pension plan as it is constituted at present requires an employer to employee contribution ratio of at least 3:1.[79] The Auditor General's report indicated that "Since 2005, the employer-employee ratio at OPG has been around 4:1 to 5:1, and significantly higher than the 1:1 ratio at the Ontario Public Service".[80] Board staff and SEC submitted that this ratio is too rich when compared with other plans. Board staff submitted that there is no evidence that this contribution ratio is required for OPG to be competitive in attracting new employees. A 1:1 ratio would reduce pension expense for the regulated business by $60M annually.[81] Board staff submitted that reductions would be $140M if special payments were included. OPG argued that the richness of the plans was the result of Ontario Hydro decisions. OPG was required to adopt collective agreements and the pension plan in 1999. The special payments relate to past service and OPG argued that changes to pension plans can be made only prospectively.
The Board is concerned that no changes were made to pension benefits in the current collective agreements. OPG had a report prepared by Towers Watson in 2011 (updated in 2013) which indicates that, absent significant changes, OPG's current pension plan is unsustainable and risks bankrupting the company.[82] OPG had this

[78] Exh F5-4-1 pages 32-36
[79] The 3:1 figure excludes special payments. If special payments are included the ratio is higher than 4:1.
[80] Exh KT2.4, Annual Report of the Auditor General, page 166
[81] Exh L-6.8-Staff-121
[82] Undertaking JT2.12 Towers Watson CHRC Briefing, December 14, 2011

report during the negotiations for its current collective agreements. Despite this, OPG signed a collective agreement with the PWU that contained no changes to the pension plan.

OPG did not file the Towers Watson report in the arbitration hearing with the Society.[83] It appears to the Board to be highly relevant that the status quo with respect to pensions was (and remains) in danger of bankrupting the company. The arbitration decision includes a lengthy section on OPG's ability to pay for the new agreement, and a section on the appropriate pension contribution. Arbitrator Albertyn concludes that no changes are necessary to the status quo with respect to pension contributions.[84] Despite Dr. Chaykowski's belief that arbitrators pay only "lip service" to a company's ability to pay,[85] the Board is concerned that OPG did not bring this very important report to the arbitrator's attention.

The Board is also concerned that OPG appears to have no concrete plan regarding how it will address the very serious issues raised in the Towers Watson report. Absent some form of intervention by the government, OPG's only solution to the problem appears to be a plan to pass all of the costs on to ratepayers in future proceedings.[86]

SEC submitted that implementation of the potential changes outlined in the Towers Watson report would reduce pension and OPEB costs by $118M annually. OPG argued that the impacts of the potential changes outlined in the report are not additive.

OPG's pension plan is extremely generous and extremely costly. The Board finds that it is not reasonable that all of these costs be passed on to ratepayers. The Board is also concerned that OPG, the largest utility the Board regulates, has a pension plan that appears to be unsustainable, and that very little seems to have been done to address this. The Board does not accept OPG's assertion that the issue of pension costs is beyond its control. The Board finds that OPG should be moving towards a 1:1 employer-employee contribution ratio, and that the 50th percentile for pension costs is the appropriate target, consistent with the Board's findings on wages and salaries. Disallowances for pension and OPEB costs are subsumed in the annual $100M compensation disallowance.

[83] Tr Vol 8 page 155
[84] Exh L-6.8-SEC-106, Attachment 1 pages 20-26, 31-32
[85] Tr Vol 8 page 156
[86] Tr Vol 8 pages 161-162

4.1.3 Other Compensation Issues

The Board is also troubled by a lack of management oversight in some areas, which was noted in the Auditor General's report. Performance reviews of unionized staff, which are supposed to be conducted prior to an employee's advancement through the salary bands, appear to often not occur. In cross examination, OPG's witness stated that there was in fact no formal requirement for performance reviews at all.[87]

The Board also notes the Auditor General's comments in its report with respect to OPG's management of overtime. The Auditor General found that "management of overtime at OPG still required significant improvement" and that in a significant number of cases there was no supporting documentation for overtime approval.[88] This has been identified as an area of poor planning, and thus the Board finds this to be an area of potential improvement in efficiency.

The Board observes the link between OPG's poor performance in the three key metrics of nuclear benchmarking presented in the annual reports based on the ScottMadden methodology (Total Generating Cost, Unit Capability Factor and Nuclear Performance Index), and high staff compensation costs. As described in further detail in the Nuclear OM&A and Benchmarking section, OPG has failed to reach the targets it set for itself in the Total Generating Cost metric. Compensation costs are a major driver of the "costs" side of the Total Generating Cost equation, and OPG's high compensation costs are undoubtedly one of the reasons that it performs so poorly on this metric. OPG's poor productivity – in other words its poor performance on the key "bang for buck" metric – results in significant incremental expense. These are matters that are broadly speaking at least partially within the control of OPG's management, and it is not reasonable to pass all of these costs on to ratepayers.

For illustrative purposes and based on the 2012 OPG nuclear benchmarking report, Board staff estimated the savings if OPG's Total Generating Cost was at the median. Costs would be reduced by approximately $300M per year (Total Generating Cost Differential x production forecast). If OPG were to actually achieve top quartile, the savings would be $725M per year. The Board will not make disallowances even close to these amounts. However poor management controls, and overall productivity are a consideration in the Board's findings.

[87] Tr Vol 8 pages 121-123
[88] Exh KT2.4, Annual Report of the Auditor General, pages 174-175.

4.1.4 Conclusion with Respect to Disallowances to OM&A for Excessive Compensation

The Board disallows $100M in each of 2014 and 2015 due to the finding of excessive compensation. As detailed above, there are several drivers to this finding: excessive salaries (chiefly relating to the PWU), excessive pension costs, too many unionized and management staff, poor performance on the Total Generating Cost metric (which is related to excessive salaries and number of staff), and a lack of management oversight with respect to performance management and overtime.

One of the Board's important functions is to act as a market proxy. Regulation exists to prevent the abuse of monopoly power. Absent regulation, monopoly service providers would be able to pass on any cost to its captive consumers, and there would be little incentive for the provider to exercise cost control or seek efficiencies. The Board finds that it would not be reasonable to pass all of OPG's compensation costs on to ratepayers.

The Board has relied to some extent on the benchmarking evidence before it in making this decision. Benchmarking analysis is commonly used by both the Board and other regulators to assist with the assessment of the reasonableness of a utility's costs or performance. OPG itself recognizes the value of benchmarking, which is shown by its support of the ScottMadden nuclear benchmarking studies. OPG's shareholder is also a supporter of benchmarking: the Memorandum of Agreement between OPG and its shareholder in fact requires OPG to benchmark itself against other electricity generators, and to set performance measures against these benchmarks.

The Board is mindful that benchmarking, while useful, is not a precise tool. It provides a high level picture of OPG's compensation situation, but cannot be expected to produce an exact dollar figure by which OPG's compensation is too high (or, in theory, too low). For this reason, the Board will not simply make disallowances based on a straight mathematical differential between OPG and the 50th percentile of the appropriate benchmark. The Board also understands that there are limits to what OPG can achieve on a year to year basis,[89] and that it has made some progress in recent years. The Board is therefore making disallowances that are significantly less than what the

[89] For example, the Government of Ontario report released on August 1, 2014, *Report on the Sustainability of Electricity Sector Pension Plans* indicates that a reasonable phase-in period for achieving a pension contribution ratio of 1:1 would be 5 years.

evidence could in theory support. The Board believes that, taking all of the factors into consideration, a $100M disallowance per year is a reasonable result.

The table below outlines the areas of concern to the Board and provides an estimate of all the costs associated with each item. Some of these items, such as the historical variance trend for hydroelectric OM&A line, are discussed in more detail in other sections. The Board is not making disallowances in the amounts shown in the chart. Rather, the table is designed to itemize the factors that went into the Board's decision to make the annual $100M disallowance. It is for illustration only, and it is not an exhaustive list of the areas where improved cost control should be achieved – for example OPG's poor performance on the Total Generating Cost metric is not included in the chart. The Board also recognizes that there may be some level of overlap between the categories.

Table 20: Factors Supporting Compensation Disallowance

Reduction in $million		2014	2015	Regulated Business Affected
1	Hydroelectric (historical base and project OM&A trend, budget vs. actual spend)	9.5	9.8	Hydroelectric
2	PWU at 50th percentile (wages only based on the AON report) includes corporate support cost reduction	96.0	94.0	Hydroelectric and Nuclear
3	Pension Cost Reduction (assume reduction to bring to comparable levels as per the AON Report and Towers Watson Report)	60.0	60.0	Hydroelectric and Nuclear
4	Management Reduction to reflect 10.5% management in total staffing – salary impact only	18.2	16.9	Hydroelectric and Nuclear
5	Reduction of 244 staff positions – wage impact only (as per the Goodnight benchmarking study.)	19.8	1.8	Nuclear

Note 1: Section 2.2 of this Decision
Note 2: Undertaking J9.11 and section 4.1.2 of this Decision
Note 3: Exh L-6.8-Staff-121 and Undertaking J9.10
Note 4: Table 18 of this Decision and Undertaking J9.7, 2014: 107.9 Management FTE x $168,297 = $18.2M, 2015: 100.3 Management FTE x $168,408 = $16.9M
Note 5: Undertaking J9.7, Total nuclear FTEs in 2013 less 244 FTEs = 8220.8 FTE, 2014: (8370.3-8220.8) x $131,149 = $19.8M, 2015: (8234.0-8220.8) x $136,918 = $1.8M

The Board recognizes that OPG will have to pay its unionized employees pursuant to the terms of its collective agreements, however the Board finds these costs to be unreasonable, and will not pass them on to ratepayers.

4.1.5 The Court of Appeal's Decision

In the previous OPG payments case (EB-2010-0008), the Board made disallowances in the amount of $145M on account of excessive nuclear compensation costs. This decision was appealed by OPG. The appeal was dismissed at the Divisional Court; however OPG was successful before the Ontario Court of Appeal. The Court of Appeal's decision has now been appealed to the Supreme Court of Canada, and that appeal is expected to be heard in December 2014.

The Court of Appeal held that OPG's test period compensation costs were "committed", and therefore were subject to a prudence review. In conducting a prudence review, the Board was not permitted to use hindsight in assessing the reasonableness of OPG's decisions to commit to the costs: in other words the Board could only use information that was available, or should have been available, to OPG at the time the costs were committed to.

Although OPG refers to its compensation costs as "committed" in its argument, it is not clear exactly what costs OPG believes have been committed to. Although collective agreements are in place for much of the test period, this is only one factor (albeit a significant one) in determining the amounts that OPG will have pay in compensation over the test period. Management costs, staffing levels, overtime costs and other cost drivers are not determined by OPG's collective agreements, and have generally not been committed to.

In the previous proceeding (EB-2010-0008) OPG also referred to its test period compensation costs as being largely "committed." Indeed that was the major issue in its appeals. However, it was revealed in this proceeding that there was in fact significant room for OPG to control compensation costs over the 2011-2012 test years: in 2011 and 2012 OPG's Business Transformation initiative ended up saving OPG almost exactly the $145M disallowed by the Board.[90] OPG's compensation costs are clearly in some measure controllable, and OPG has effectively acted to control them to some degree in the past.

Even to the extent that OPG's 2014 and 2015 compensation costs are "committed", the Board has considered the Court of Appeal's decision and is satisfied that it has taken the decision into account. The Court of Appeal's decision states that the Board cannot

[90] Tr Vol 3 pages 68-69, 134

use hindsight in assessing the prudence of committed costs. Even if one were to accept that OPG's test period compensation costs are entirely committed, the Board is not using hindsight to assess the reasonableness of OPG's collective bargaining practices (or any other compensation costs). All of the evidence relied on by the Board is information that OPG either had available to it when it committed to its compensation costs, or should have had before it.

4.2 Pension and Other Post-Employment Benefits Accounting (Issue 6.8)

OPG's historical and forecast pension and OPEB expenses are summarized in the following table. The current service cost of pension and OPEB is part of compensation while the remainder is part of centrally held costs.

Table 21: Pension and OPEB

	$million	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual	Total 2008-13	2014 Plan	2015 Plan
	Pension									
1	Accrual Basis - recoverable in payment amounts	121.4	141.4	150.1	195.0	286.1	383.3		471.3	405.3
2	Cash Basis	198.6	206.1	208.5	235.5	297.1	242.9		321.9	329.6
3	Difference (1-2)	(77.2)	(64.7)	(58.4)	(40.5)	(11.0)	140.4	(111.4)	149.4	75.7
	Other Post-Employment Benefits									
4	Accrual Basis - recoverable in payment amounts	119.2	162.5	161.0	173.2	203.0	231.3		204.6	212.8
5	Cash Basis	44.2	43.1	43.4	48.4	57.9	61.2		89.6	95.8
6	Difference (4-5)	75.0	119.4	117.6	124.8	145.1	170.1	752.0	115.0	117.0

Source: Chart 4 AIC, JT2.40, J9.6, Exhibit N2
2008-2013 excludes newly regulated hydroelectric
Note 1: The source for the 2015 and 2014 cash basis is J9.6

For 2014 and 2015, OPG proposes rate recovery of its pension and OPEB costs based on the accrual method of accounting: $1,294M in total. As noted in lines 1 and 4 of Table 21, in 2014, $471.3M would be recovered for pensions and $204.6M would be recovered for OPEBs. In 2015, $405.3M would be recovered for pensions and $212.8M would be recovered for OPEBs. The accrual basis recognizes these expenses when the entitlement to pension and OPEB is earned, not when OPG actually has to pay them out.

SEC submitted that pensions and OPEB recovery should be determined on a cash basis. CME, CCC and LMPA supported SEC's submissions to use the cash basis for rate recovery. The cash basis recognizes the expense when cash payments are made, as opposed to the accrual method in which the expense includes future liabilities. In theory, over time, the accrual and the cash method should result in the exact same amount of total expense.

Board staff supported use of the cash method for pensions and the accrual method for OPEBs, provided that OPG be directed to set up an irrevocable trust or fund for the recovery in excess of OPEB cash requirements. In the absence of a set-aside mechanism, Board staff supported the use of the cash basis for both pensions and OPEBs.

For tax purposes, a tax liability is created on OPG's corporate financial statements when the accrued expense exceeds the cash expense. Including an amount to recover the tax liability associated with higher accrued expenses increases the proposed revenue requirement. Parties submitted that adopting the cash method would reduce the proposed revenue requirement by $609.4M in 2014 and 2015, not just the $457.1M[91] difference between the cash and accrual expenses because of the decreased tax recovery amount.

There is currently no consistency among utilities in the use of either cash or accrual method for rate recovery of pension and OPEB costs. Both methodologies have been approved by the Board. The Board has approved OPG's payment amounts based on the accrual method since EB-2007-0905, the first cost of service proceeding. OPG indicated that the majority of regulated entities use the accrual method. OPG submitted that the Board should consider the accounting and ratemaking treatment of pensions and OPEB as part of a generic proceeding. Until the generic proceeding is concluded, OPG proposed the Board maintain the accrual method for determining payment amounts.

Board staff submitted that the cash basis for pension and OPEB determination has been more stable and will continue to be more stable than the accrual basis which is significantly affected by discount rates. OPG replied that there is no basis for claims or predictions on the magnitude or direction of the difference between the cash and accrual method.

[91] Sum of 2014 and 2015 for lines 3 and 6 of Table 21

Based on review of 2008 to 2013 data, Board staff determined that OPG has been authorized to collect $752M more in OPEB and $111.4M less in pension expenses than OPG has been required to pay out. Board staff submitted that OPG has used this over-collection for general corporate purposes, and that the money has not been set aside to cover the costs when they actually come due at some point in the future. Board staff submitted that the historical over-collection of $752M could be used to offset the regulatory liability for future OPEB costs.

Extrapolating the 2014-2015 trend, Board staff estimated OPG could over-collect $1.2 billion in OPEB expenses within the next 10 years. OPG's witnesses agreed that cash amounts would likely be less than accrual amounts for the next 10 years for OPEBs, but disagreed with Board staff's estimate of $1.2 billion in over collection.

OPG characterized Board staff's suggestion that the $752M difference between the cash and accrual methods be used to offset future cash expense as a claw back. OPG argued that the cash flow generated from payment amounts is spent as OPG determines. In addition, there is no link to the pension and OPEB costs approved in payment amounts to what OPG ultimately spends.

OPG argued that if the cash basis is used for ratemaking, it would ultimately be required to increase its borrowings. Ratepayers would be required to pay for that debt and OPG's financial ratios would be affected.

OPG indicated that USGAAP requires the use of accrual accounting for pensions and OPEB to be used in its corporate financial statements, and that if recoveries from ratepayers were on a cash basis, OPG would not be able to record the difference as regulatory assets. Board staff noted that Hydro One, which also reports under USGAAP, recovers pension expense on a cash basis with no apparent conflict with USGAAP.

Board staff submitted that the Board could consider the cash basis for pension and OPEB for the test period pending a generic proceeding on pension and OPEB costs and recovery mechanisms.

Board staff submitted that if the Board were to approve recovery based on the cash method a new variance account would be required, since OPG has the discretion to contribute more than the minimum amount determined by its actuary to the pension plan. The variance account would enable the tracking of any additional cash contributions made by OPG to be considered in the future for recovery.

OPG submitted that the determination of pension and OPEB expense was not an issue on the issues list and that OPG did not file expert evidence on the matter, nor did any other party. In OPG's view, the matter is very complex and best suited to a generic proceeding.

Fund or Irrevocable Trust for OPEB

While OPG makes contributions to a registered pension plan, there is no equivalent plan for OPEB. The accrual amounts are determined by OPG's actuary and used in OPG's corporate financial statements as required under USGAAP. OPG's actuary also determines the minimum cash requirements for its pension and OPEB plans based on legislation and regulations.

Board staff submitted the Board could approve the accrual method for OPEB on the condition that OPG establishes a set-aside mechanism, such as an irrevocable trust or fund for OPEB, similar to what was referred to the in the Federal Energy Regulatory Commission's Statement of Policy report PL93-1-000.[92] Board staff also submitted that if the Board had any reservations about a fund or trust, the Board could limit recovery of OPEB expense as determined by the cash method, or OPG's out-of-pocket test period costs. OPG submitted that the Board has no jurisdiction to order OPG to set up an irrevocable trust or fund. OPG argued that the matter is complex and submitted that a segregated fund could be considered as part of a generic proceeding.

Board Findings

The Board will only allow OPG to recover its cash requirements for pensions and OPEBs in 2014 and 2015, approving a revenue requirement of $836.9M for pension and OPEB.

The Board will reduce the total proposed amount to be recovered in rates by $457.1M, which is a reduction of $225.1M in proposed pensions and $232.0M in proposed other

[92] Exh K13.2, FERC PL63-1-000, Post-Employment Benefits Other Than Pensions, Statement of Policy, December 17, 1992

post-employment benefit amounts.[93] OPG's most recent actuarial valuation as at January 1, 2014 by AON Hewitt was filed in evidence.[94] The Board relies on the AON Hewitt valuations of the cash requirements in 2014 and 2015 and sets OPG's payment amounts accordingly.

In addition, the Board approves the establishment of a new deferral account to record the differential between the accrual and cash valuations for pension and OPEB expenses. The Board's reasons follow in the sections below.

OPG and some parties suggested that the Board hold a generic hearing to review pension and OPEB costs. The Board agrees and believes that a generic proceeding on the regulatory treatment and recovery of pension and OPEB costs would be beneficial. A generic proceeding could enhance understanding of the different rate making options, establish policy and decide on how best to apply that policy to OPG and other Board-regulated entities. Transition to a different accounting treatment of pensions and OPEBs for OPG, if required, would be addressed by the Board in OPG's next cost of service proceeding, having been informed by the outcomes of the generic proceeding.

The Board is not necessarily permanently moving from an accrual to a cash basis for setting OPG's payment amounts. The Board is providing OPG with sufficient revenue to fund its cash needs for 2014 and 2015 until a comprehensive review of pensions and OPEB is undertaken through a generic proceeding. The Board is concerned that any money collected from ratepayers today, in excess of the cash requirements, is not being used to fund future pension and OPEB cash requirements. The Board has considered both OPG's needs and those of ratepayers. In the absence of a Board policy, the Board will not allow the collection of funds from ratepayers in 2014 and 2015, of an amount higher than OPG's cash needs, when OPG's use of the excess funds is not understood, and the benefit to ratepayers is uncertain.

Until Board policy is established, the Board approves a new deferral account to record the differential between the accrual and cash valuations for pension and OPEB expenses. Based on the policy outcome of the generic proceeding, a future panel will decide on the appropriate disposition (if any) of the deferral account balance.

[93] Undertaking J9.6 states that the 2015 pension requirement on a cash basis is $329.6M. Correcting the 2015 pension requirement on a cash basis in Chart 1 of undertaking J13.7 results in a, accrual vs cash difference of $457.1M.
[94] Undertaking J9.6

At this time, the scope of the generic proceeding is unknown. For clarification, the Board is not setting aside the difference between the cash and accrual amounts for this test period, for purposes of another future prudence review of these costs. The 2014 and 2015 payment amounts will be final in that respect. Any future treatment regarding the deferral account would be limited to the outcomes of the generic proceeding as they relate to the accounting or mechanics of recovery, as applicable.

The application indicated a differential amount of $457.1M based on the 24-month period in 2014 and 2015. However, the $457.1M will be subject to change given the approved effective dates of the payment amounts and OPG's final actuarial evaluations at the end of 2014 and 2015.

OPG indicated that the determination of pension and OPEB expenses for ratemaking was not an issue on the issues list. The Board agrees that the exact words "accounting methods for ratemaking" were not on the issues list. However, the issue was raised in numerous interrogatories and extensively during the pre-hearing technical conference and the oral phase of the hearing. In addition, every proposed expense, particularly material expenses of $1,294M, must be reviewed by the Board to order to determine OPG's payment amounts.

OPEB Costs

Board staff submitted that historical over collection of OPEB expenses should be used to offset the regulatory liability for the future. OPG submitted that Board staff's proposal amounts to a "claw back". The Board does not agree with OPG's characterization and the use of the term "claw back". The amount and use of any excess collected to date from ratepayers must be clearly understood and resolved before the Board allows any further collection in excess of requirements in 2014 and 2015.

On a prospective basis, Board staff estimated that maintaining accrual accounting for ratemaking would result in an over-collection in OPEB revenue of $1.2 billion every 10 years. OPG took issue with Board staff's $1.2 billion estimate. OPG's witnesses indicated a cash flow analysis had been completed, yet were unable to provide any specifics, stating it would be "likely in the next 10 years"[95] before actual OPEB cash payments would exceed the accrual expense. The Board does not find OPG's answer sufficient. The Board has little evidence by which to understand the magnitude or

[95] Tr Vol 13 page 134

duration of the potential over collection of OPEB costs from ratepayers, but the prospective numbers are alarming.

The Board is not confident OPG has undertaken the level of cash flow analysis required to ensure it will have sufficient cash available as a corporation, when its cash needs exceed accrued expenses. It would be inappropriate to collect revenues today in excess of cash requirements and then turn to ratepayers in the future, when cash requirements exceed accrued expenses. The Board must ensure ratepayer interests over time are fully considered.

Pension Costs

From 2008-2013 cash funding requirements for pensions exceeded accrued expenses by $111.4M; the opposite of OPEB costs. However, in 2014 and 2015 accrued pension expenses exceed cash funding requirements by $149.4M in 2014 and $75.7M[96] in 2015.

With accrued pension expenses exceeding cash requirements in 2014 and 2015, the Board's concerns relating to OPEB costs regarding the magnitude and duration of over collection and the associated cash flow analysis apply equally to pension costs.

Prior Board Decisions

The Board is directing the use of the cash basis of recovery for 2014 and 2015. This is different from prior OPG decisions. In OPG's last cost of service proceeding, EB-2010-0008, the Board found no compelling reason to change OPG's approach of using the accrual method. The Board noted that consistency in accounting treatment which allows comparison of year-over-year results to be advantageous for assessing reasonable cost levels.

This panel agrees with the EB-2010-0008 decision as consistency is desirable in order to compare these costs. However, in this case the benefits of consistency are outweighed by the concern regarding the significant increase in payment amounts to recover accrued expenses. In 2011 and 2012, the accrued expenses for pensions were $195.0M and $286.1M respectively. In 2014 and 2015, the forecast accrued expenses are almost double at $471.3M and $405.3M.

[96] After adjusting the cash contribution number in 2015 to the amount shown in J9.6 of $329.6M.

In reply submission, OPG indicated that while the figures may be different from its last cost of service proceeding in EB-2010-0008, “the circumstances have not changed”. The Board disagrees. The circumstances have changed as the accrued expenses are increasing and volatile, dependent upon the assumptions adopted by OPG’s management, such as the appropriate discount rate. Volatility in the test years was evident when OPG filed its Exhibit N1 impact statement in December 2013, months after filing its Application. After updating the discount rate and mortality rate assumptions applied to its pension plan, accrued expenses in 2014 and 2015 increased, exceeding OPG’s materiality threshold and increasing the proposed revenue requirement by $142.3M. This was followed by the Exhibit N2 impact statement filed in May 2014, which based on higher discount rates for the pension plan, decreased the revenue requirement by $278.7M.

Implications of Cash Method

OPG submitted that the cash basis would ultimately require OPG to increase its borrowings and ratepayers would have to pay for that debt. In addition, the cash basis would affect financial ratios. The Board has approved OPG’s capital expenditures and rate base for 2014 and 2015. The payment amounts include a weighted average cost of capital. In addition, every cost that OPG requires to recover to run its business and the opportunity to realize its regulated rate of return, underpins the payment amounts. The Board does not understand what additional borrowing would be required to fund the regulated side of OPG’s business.

OPG prepares its financial statements in accordance with USGAAP, which requires pensions and OPEB costs to be determined on the accrual method. In reply argument, OPG identified corporate financial reporting issues such as qualified audit opinions and the recognition of existing regulatory assets if the Board were to utilize the cash basis for ratemaking while its corporate financial statements were based on the accrual method. The issue of cash versus accrual is one of timing. This Board does not regulate financial reporting requirements, but is confident OPG’s management, its Audit Committee and external auditors will reflect the outcomes of this Decision in its financial statements.

Given the Board’s position on these matters, the additional information provided by OPG in its reply argument regarding its discussions with Ernst & Young LLP was not helpful to the Board. As an aside, however, the Board also notes that it is not generally appropriate to file “new evidence” following the closing of the evidentiary portion of the proceeding.

Pension and OPEB Cost Variance Accounts

OPG has the ability to contribute additional funds to its pension plan in excess of the minimum cash requirements to reduce its unfunded liability. The Board recognizes this opportunity and does not want to dissuade OPG from contributing more than the cash amounts approved in its payment amounts. The total unfunded liability on OPG’s corporate balance sheet was $5,469M as of December 31, 2013: a pension deficit of $2,461M; a supplementary pension plan deficit of $289M; and OPEB deficit of $2,719M. In addition, AON Hewitt determined the pension plan had a small solvency deficit on January 1, 2014, which will require additional funds to eliminate.

The Board will use its available ratemaking tools so as to not discourage OPG from making additional contributions, in addition to its minimum cash requirements, to decrease its unfunded liability without financial hardship. The Board approves a new variance account to track any contributions that differ from the minimum cash requirements, as included in the 2014 and 2015 payment amounts. Interest will apply to this variance account given that it relates to cash payments.

In addition, the Board has approved the establishment of a new deferral account to track the differential between the accrued and cash valuations for pensions and OPEBs. The Board approves the accrual of interest on the variance account balance related to additional cash contributions made, but does not approve the accrual of interest on the deferral account balance given that it tracks non-cash items. This treatment is consistent with OPG’s current variance account based on the accrual method.

Given the effective date for OPG’s 2014 and 2015 payment amounts, the current payment amounts which include accrued pension and OPEB expense will remain in place until November 1, 2014. Correspondingly, the current Pension and OPEB Cost Variance Account will operate until that date to track variances from actual to forecast accrued expenses. After the effective date, the new variance account will be used to track variances from actual to forecast cash expenses. The new deferral account will capture initially the differences between cash and accrual pension and OPEB amounts included in evidence commencing with the effective date. The deferral account balance should be adjusted for future actuarial valuations and actual cash payments on an annual basis until considered by the Board.

4.3 Corporate Support Costs

(Issue 6.9)

OPG is structured such that certain corporate groups provide services and incur costs in support of the hydroelectric and nuclear businesses. Corporate groups include Business and Administrative Services, Finance, People & Culture, Commercial Operations & Environment, and Corporate Centre. OPG is asking for approval of corporate support costs, which are $505.8M in 2014 and $483.9M in 2015.

As shown in Table 5 (to a minor extent),Table 13 and the following table, corporate support costs have increased significantly over the 2011 - 2013 period due to the implementation of a centre-led organization driven by the Business Transformation initiative.

Table 22: Corporate Support Costs

$millions	2010 Plan	2010 Actual	2011 Approved	2011 Actual	2012 Approved	2012 Actual	2013 Budget	2013 Actual	2014 Plan	2015 Plan
Nuclear	247.0	226.5	249.2	233.1	450.3	408.4	451.0	428.3	433.9	417.4
Previously Regulated HE	25.1	22.4	24.8	22.0	29.0	24.5	29.7	26.1	29.8	26.9
Newly Regulated HE							38.8	35.2	42.1	39.6
Total	272.1	248.9	274.0	255.1	479.3	432.9	519.5	489.6	505.8	483.9
Source: Exh F3-1-2 Tables 1,2,3 Exh F3-1-1 page 2 and 3, Exh L-1-Staff-2										

Board staff observed that many of the corporate support functions are what AON Hewitt would compare with “general industry”. The AON Hewitt National Utility Survey indicated that the general industry comparable jobs are significantly overpaid by OPG by about 20 to 29% versus P50 (the 50th percentile). The Auditor General’s analysis of administration, finance and human resources jobs indicated that the majority of these jobs are overpaid at OPG as compared with the Ontario Public Service. The Auditor General also observed that the Goodnight benchmarking found that nuclear support functions were generally overstaffed while nuclear operational functions were generally understaffed. OPG replied that it is bound by collective bargaining and committed costs cannot be reduced.

OPG has access to raw cost data from EUCG for the information technology function and Electric Utility HR Metrics Group for the human resources function. OPG prepares benchmarking reports from this data, but there is no independent benchmarking analysis. Board staff observed that the last independent benchmarking study of the finance function was conducted in 2010 based on 2008 data. Board staff submitted that independent benchmarking of the corporate support function is required given the significant changes resulting from Business Transformation. The analysis would need to be normalized and reflect the period before and after Business Transformation.

The 2011 information technology and 2012 human resources benchmarking results prepared by OPG indicate that OPG is not performing in the top quartile with respect to cost. Board staff submitted that test period OM&A reductions would be appropriate. However, OPG argued that the submission did not recognize the benefits that OPG achieved in the contract with its information technology service provider and that the Board staff interpretation of the human resources benchmarking was not appropriate.

Given the consistent over-forecasting, Board staff submitted that a $25M reduction to nuclear OM&A was appropriate. LPMA determined that the previously regulated hydroelectric facilities corporate support costs were 11.7% over-forecast in the 2010 to 2013 period and proposed reductions of $8.4M in 2014 and $7.8M in 2015. On the basis of 7.2% over-forecasting in the historical period, LPMA proposed reductions of $31.2M in 2014 and $30.1M in 2015 for nuclear corporate support costs. SEC submitted that OPG corporate support costs should be reduced by $35M in each of the test years on the basis of historical over-forecasting and benchmarking results. OPG argued that all of these submissions should be rejected as they do not address the evidence in relation to the test period costs, or consider the reasons for the historical variances.

Board Findings

OPG introduced the Business Transformation initiative in 2011 and implemented the centre-led organization in 2012. The Board acknowledges the impact of OPG’s Business Transformation initiative on the number of staff, including corporate support staff. Efficiencies should be achieved and duplication reduced with the organization for corporate support functions.

In addition, the Board acknowledges OPG's commitment to proceed with an open competition for the next IT service contract[97] as a positive step, however any cost savings will not impact the test period.

The Board finds the Goodnight nuclear staffing analysis was informative for this proceeding. While corporate support functions were reviewed by Goodnight, only corporate support dedicated to the support of nuclear operations was considered.

The Board finds the internal benchmarking analysis undertaken by OPG based on the raw cost data from EUCG for the information technology function and Electric Utility HR Metrics Group for the human resources function to be inadequate. The human resources benchmarking is based on 2012 data, the information technology benchmarking was based on 2011 data and no recent benchmarking was filed for the finance function. Efficiency gains in the corporate support functions are not apparent in the benchmarking information that OPG has filed with the application.

Parties indicated that OPG has historically forecast higher corporate support costs than it actually spent. The Board finds it difficult to draw conclusions from the historical variance analysis as provided in evidence, as the underlying numbers are affected by employee migration to centre-led functions as a result of Business Transformation. Corporate support costs have increased significantly over the 2011 to 2013 period, but it is not clear to the Board that there has, or will be, an off-setting reduction in the other business units as a result of OPG's centre-led restructuring.

The Board made a disallowance of $100M to OPG's OM&A proposed budgets for 2014 and 2015 for overall compensation, which includes employees in corporate support functions. The Board will not make a further reduction related to corporate support costs.

The Board directs that an independent benchmarking study be undertaken of corporate support functions and costs given the significant changes resulting from the Business Transformation initiative. The results of this study will need to be shown in a manner that facilitates transparent comparison before and after Business Transformation.

[97] Technical Conference Tr April 23, 2014, page 138

4.4 Centrally Held Costs

(Issue 6.10)

Centrally held costs are company-wide costs recorded centrally. They are:

- Pension and OPEB costs not directly included in business unit costs
- Insurance
- Performance incentives
- IESO non-energy charges
- Other – labour related costs, ONFA guarantee fee, business claims and settlements

Pension and OPEB costs are discussed in the Pension and OPEB Accounting section of this Decision. Performance Incentives are discussed in the Compensation section. There were no submissions on the other components of centrally held costs. The Board approves OPG's test period proposed expense for centrally held costs other than pension and OPEB and performance incentives.

4.5 Asset Service Fees and Other Operating Costs

(Issues 6.14 and 6.15)

Service fees for centrally held assets, e.g. OPG head office, are charged to the regulated and unregulated businesses. No submissions were filed on the matter.

The Board approves the proposed asset service fee amounts of $1.5M and $1.7 M for the previously regulated hydroelectric facilities, $2.9M and $3.0M for the newly regulated hydroelectric facilities and $23.3M and $26.8M for the nuclear facilities for the years 2014 and 2015 respectively.

In deriving the asset service fees OPG followed the methodology accepted by the Board in EB-2010-0008. The increases over the test period have been sufficiently explained and are reasonable. The allocation to each of the businesses is approved.

4.6 Depreciation

(Issues 6.11 and 6.12)

There were two key issues to be considered in respect of depreciation: first, the appropriate method for the determination of service life and second, the appropriate service life for the Niagara Tunnel.

As directed by the Board in EB-2010-0008, OPG filed an independent depreciation study undertaken by the consultant Gannett Fleming.[98] An updated study was filed to account for recent material changes, e.g. the Niagara Tunnel Project.[99]

The Gannett Fleming study was based on the average life group method which applies a common life estimate to each of the asset vintages and each of the assets within each vintage. Board staff submitted that OPG should be directed to file another independent depreciation study using the equal life group method which segregates assets into groups of assets with the same life expectancy and plant-life statistics are derived from the group's estimated survivor curve. OPG submitted that the Board should reject that submission. Gannett Fleming's position is that while the equal life group method is superior, there is insufficient information in the case of OPG's assets to apply this method. The Gannett Fleming report also noted that other regulated utilities, e.g., Enbridge Gas Distribution and Union Gas use the average life group method.

OPG submitted that it would be too costly to develop the data to support the equal life group method, and that it is impractical and potentially impossible to do so.

Submissions were also filed on the service life of the Niagara Tunnel. Gannett Fleming recommended 95 years. It was not apparent from the Gannett Fleming studies that the useful lives of the two existing tunnel linings (Sir Adam Beck) were actually 120 years. In an interrogatory response,[100] OPG informed the Board that in 1999 it had extended the useful lives of these assets. As the Sir Adam Beck tunnels have been in-service for close to 60 years and have an assumed useful life of 120 years, Board staff submitted that the Niagara Tunnel should be expected to have a service life in the range of 125 to 150 years, and that a mid-point of 135 years would be a reasonable estimate given the advanced technology and materials used for its construction. LPMA proposed 138

[98] Exh F4-1-1 Attachment 1
[99] Exh F5-1-3
[100] Exh L-6.12-Staff-160(e)

years and SEC proposed 150 years. OPG argued that there was no evidentiary basis for the proposals of the parties.

Board Findings

The Board finds that OPG responded appropriately to the direction in EB-2010-0008 by having an independent depreciation study undertaken. The Board accepts the study results, predicated on OPG's continued application of the average life group method. The Board will not require OPG to file another study using the equal life group method, as the data is not available. The Board accepts Gannett Fleming's evidence that OPG lacks the necessary data to use the equal life group method and the cost to develop the data would be prohibitive.

OPG's depreciation and amortization expense for the test period incorporates all the recommendations made by Gannett Fleming. The Board accepts the evidence of Gannett Fleming and its recommended 95 year useful life for the Niagara Tunnel. Although the useful lives of the Sir Adam Beck Tunnels are longer than 95 years, the useful lives were reviewed and extended after 45 years in-service. The Board will not consider extending the useful life of the Niagara Tunnel at this time.

The Board approves the depreciation expenses as filed to be included in the calculation of the payment amounts.

4.7 Taxes

(Issue 6.13)

OPG seeks approval for property taxes of $16.3M in 2014 (assuming full year for the newly regulated hydroelectric facilities) and $16.8M in 2015 for the regulated business. No submissions were filed on property taxes, and the Board approves OPG's request.

OPG uses the taxes payable method for determining regulatory income tax for the regulated facilities. The tax is allocated based on each business's regulatory taxable income. OPG seeks approval of income tax expense of $187.9M in 2014 (assuming full year for the newly regulated hydroelectric facilities) and $123.7M in 2015 for the regulated business.

This section addresses two sub-issues relating to a tax loss carry-forward from 2013 and deferred taxes associated with the newly regulated hydroelectric assets.

4.7.1 Tax Loss Carry-Forward

In 2013, OPG incurred a regulatory tax loss of $211.6M that OPG attributes to a shortfall in nuclear production. OPG submitted that the associated tax loss carry-forward that was created should not be applied to regulatory taxable income in 2014 to reduce the tax provision included in the payment amounts. OPG argued that OPG's shareholder incurred the costs associated with the loss in 2013 and should receive the benefit of the resulting tax loss carry-forward in 2014. As a result, OPG posted an accounting entry to its corporate retained earnings, to the benefit of its shareholder. OPG relied upon a principle that "benefits follow costs" as stated in the *Accounting for Public Utilities*, published in the United States in 2005 to support its proposal.

> …if ratepayers are held responsible for costs, they are entitled to the tax benefits associated with the costs. If ratepayers do not bear the costs, they are not entitled to the tax benefits associated with the costs.[101]

OPG also referred to two prior decisions in which the Board referenced this principle, namely the OPG EB-2007-0905 decision and the Great Lakes Power EB-2007-0744 decision. In OPG's submission, the situation in 2013 is similar to the situation in 2007 when it incurred a tax loss and the Board did not approve the associated tax loss carry-forward for determining OPG's 2008 payment amounts.

OPG also argued that the Board cannot adjust rates in a future period without a deferral or variance account, as this would amount to retroactive ratemaking.

Board staff submitted that the tax loss should be carried forward and applied to the test period tax provision to the benefit of ratepayers. OPG's payment amounts that were in effect in 2013, when the tax loss occurred, included a recovery amount for income tax. The 2013 payment amounts were established based on the 2011 and 2012 test period and included recovery of approved income tax amounts of $60.9M and $91.1M respectively. The payment amounts approved for 2011 and 2012 persisted into 2013 as OPG did not apply for new 2013 payment amounts. Board staff submitted that since

[101] Accounting for Public Utilities, by Robert Hachne and Gregory Aliff, Part V, Chapter 7, September 17, 2005

ratepayers have borne the tax costs included in the payment amounts in 2013, the 2013 regulatory tax loss carry-forward calculated by OPG should be used to reduce regulatory taxable income in 2014.

Board staff submitted that this treatment is consistent with the Board's long-established policy requiring tax loss carry-forwards to be applied to reduce regulatory taxable income, as stipulated in the 2006 Electricity Distribution Rate Handbook.[102] At the hearing, Board staff cited several Board examples of electricity distributors in their rate applications carrying forward income tax losses from a prior year(s) to reduce or eliminate taxable income in a future year's test period. In addition, Board staff cited several Board decisions approving tax loss carry-forwards to reduce regulatory income taxes.

LPMA and CME supported Board staff's submission.

SEC supported Board staff's submission yet also referred to the "benefits follow costs" principle which was used by the Board in OPG's first payment amount decision (EB-2007-0905). SEC submitted that the "benefits follow costs" principle was used by the Board to ensure that there was a principled way of allocating costs and benefits to regulated and unregulated periods, which was not the case for OPG in 2013. In this case, the loss arose during a period in which OPG was collecting regulated rates from ratepayers. That is a similar situation to the electricity distributors, who do have to apply tax loss carry-forwards in one regulated year to reduce taxable income in subsequent regulated years.

SEC submitted that the "benefits follow costs" principle was never intended to allow a utility to collect money from ratepayers for PILs, then keep that money for their own purposes because they were unable to operate the regulated business at a profit.[103]

In reply, OPG argued that Board staff incorrectly applied the principle in its submission and SEC fundamentally misunderstood the Board's application of the principle. OPG asserted that the tax loss arose because of an operating loss. As OPG and its shareholder had to bear the operating loss, not ratepayers, OPG submitted that its shareholder is entitled to receive the benefit of the associated tax loss.

[102] 2006 Electricity Distribution Handbook, May 11, 2005, page 61
[103] SEC Final Argument page 72

Board Findings

The Board directs OPG to reduce its 2014 income tax provision to recognize and carry forward its regulatory tax loss in 2013. This finding is consistent with Board policy as indicated in the Board's 2006 Electricity Distributor's Rate Handbook (the "Handbook") and in subsequent Filing Requirements.[104] The Board understands the policies contained in the Handbook and the Filing Requirements apply to electricity distributors, not directly to OPG as an electricity generator, yet finds that the underlying Board policy should be applicable to OPG in this application.

The rate regulation of the electricity distribution sector shows a history of tax loss carry-forwards being routinely used in the rate setting process for distributors. This approach is completely consistent with Board policy for tax losses to be applied to reduce income tax to be included in rates, and there is no reason for OPG to be treated any differently in this instance.

OPG referred to two decisions in which the Board did not apply the policy, namely OPG's EB-2007-0905 decision and Great Lakes Power's EB-2007-0744 decision. The Board finds that the circumstances in these two cases were unique and are not comparable to OPG's current circumstances.

The Board's findings in the EB-2007-0905 decision address the fact that OPG was not regulated by the Board prior to 2008, when the tax loss occurred. The Government set OPG's rates in 2005, 2006 and 2007. The Board's EB-2007-0905 decision in 2008 did not reference the policy in the Handbook. The Board finds that the circumstances in OPG's first payment amounts proceeding were unique and the Board's finding in that case resulted from the absence of information and the Board's uncertainty regarding OPG's tax calculation.

> The Board is not convinced that there are any "regulatory tax losses" to be carried forward to 2008 and later years, or if there are any, that the amount calculated by OPG is correct….The Board does not have the information necessary to determine the tax benefits which should be carried forward to offset payment amounts in 2008 or later periods.[105]

[104] A requirement to identify any loss carry-forwards and when they will be fully utilized has been included in the Board's Filing Requirements for electricity distributors' cost of service applications since 2012. With the issuance of the 2012 Filing Requirements (for 2013 rates), the Board included any remaining relevant sections of both the 2000 and 2006 Electricity Rate Handbooks.
[105] Decision with Reasons, EB-2007-0905, pages 169-170

The circumstances in the Great Lakes Power EB-2007-0744 proceeding were unique as Great Lakes Power Limited conducted both regulated and non-regulated businesses. The Board's decision addressed the fact that the corporate tax loss carry-forwards arose due to losses in Great Lake Power Limited's non-regulated businesses. The Board referred to the "stand-alone principle" and that it would be inappropriate for regulated service rates to be affected by the income or loss of a non-regulated business.[106]

> It would be fundamentally unfair to take such tax losses into account when setting rates for regulated service. To abandon the stand-alone principle in this case would give rise to the inappropriate result that rates for regulated service would be affected by the income or loss of a non-regulated business.

OPG's circumstances in 2013 are distinct from the two referenced Board decisions. In 2013, when OPG's tax loss arose, OPG was regulated by the Board and there is no evidence filed to indicate the tax loss was related to OPG's non-regulated businesses. To the contrary, the first line of OPG's reply argument under the Loss Carry-Forward section heading states that the $211.6M regulatory tax loss in 2013 was due to a shortfall in nuclear production.

OPG made a decision to maintain its (then current) payment amounts for 2013. OPG decided not to apply to the Board to change its payment amounts for 2013 based on updated information, including an updated nuclear production forecast. The fact that OPG incurred a tax loss was a risk OPG decided to take on its own accord and should not change the application or treatment of the Board's tax loss carry-forward policy.

In addition, even if one accepted the argument that the circumstances of these prior cases were similar to OPG in 2013, the Board continued to apply the Handbook's policy to electricity distributors after both of those decisions were issued.[107] Accordingly, the Board does not consider either case to have set a precedent. Further, it is apparent to the Board from the submissions of OPG and the parties that the "benefits follow cost" principle has been interpreted differently by the parties.

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[106] Decision and Order, EB-2007-0744, Great Lakes Power, pages 40-41
[107] Decision and Order, EB-2008-0322, Hydro One Remote Communities, page 10, Decision and Order, West Perth Power and Clinton Power Corporation, EB-2009-0262/EB2010-0121, page 22

OPG argued that application of the policy would result in retroactive rate making during the term of a final rate order without a deferral or variance account. The issue before the Board is a tax loss carry-forward. The tax loss is carried forward to a subsequent year by definition. The question in this application is whether OPG's shareholder or its ratepayers receive the future benefit, the opportunity to reduce a future year's tax provision by the amount of the tax loss from a prior year.

The Board does not find there to be an issue with retroactive rate making in the context of tax loss carry-forwards in this case. The Board policy was established in 2005 and it has been applied in subsequent years. The Board's Handbook policy did not and does not require the establishment of a deferral account. Therefore, there is no issue of retroactive ratemaking in the Board's view.

4.7.2 Deferred Tax

The December 31, 2013 audited financial statements indicate $181M in deferred income taxes for the newly regulated hydroelectric facilities. OPG submitted that the deferred income taxes on OPG's December 31, 2013 financial statements is to be excluded from the revenue requirement impacts associated with regulating the newly regulated hydroelectric assets. The deferred tax is related to pension and OPEB expense recognition and higher capital cost allowance that is allowed for tax purposes compared to OPG's accounting depreciation.

The Board is required to accept the assets and liabilities of the newly regulated hydroelectric facilities as set out in OPG's December 31, 2013 audited financial statements. This requirement is set out in O. Reg. 53/05, section 6(2)11 part 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.

SEC submitted that the $181M net tax liability has been charged as an expense by OPG prior to January 1, 2014, but has not actually been paid yet. SEC disagrees with OPG's proposal which would require ratepayers to pay for tax costs in the future, tax costs incurred prior to the regulation of the newly regulated hydroelectric facilities. SEC submitted that would result in retroactive ratemaking and would be unfair to ratepayers. SEC noted that the Board has never determined that it is appropriate to allow recovery of tax expenses in rates when the taxes were incurred prior to regulation by the Board.

SEC submitted that there is nothing in O. Reg. 53/05 to indicate that the government intended the Board to allow OPG to collect pre-2014 tax expenses from ratepayers in 2014 and beyond. SEC submitted that if the government had intended to require the Board to adopt such a rule, it would have been explicit.

LPMA and CME supported SEC's submissions.

OPG argued that SEC has not considered the entire provision of section 6(2)11 of O. Reg. 53/05. OPG submitted that the wording explicitly provides that the Board, in making its first order, must accept the assets and liabilities approved by the board of directors, including values relating to income tax timing differences and the revenue requirement impact of accounting and tax policy decisions.[108] As deferred tax liabilities relate wholly to income tax timing differences, OPG submitted that the regulation is clear and explicit. Further, OPG stated that the government was aware of the deferred tax liability through its review of OPG's business plan prior to the creation of the regulation.

OPG also observed that implementation of the regulation as a means to delineate a starting point was accepted by the Board in OPG's first proceeding in EB-2007-0905.

Board Findings

The Board's EB-2007-0905 decision dealt with tax issues that arose prior to regulation of OPG's prescribed assets. In that decision, the Board found that the benefit of tax deductions and losses that arose before the date of the Board's first order should be apportioned between electricity consumers and OPG based on the principle that the party who bears a cost should be entitled to any related tax savings or benefits.

The requirement set out in O. Reg. 53/05, section 6(2)11part ii, applicable to the newly regulated assets, is more descriptive than the requirement set out in 2008 when the Board issued its first rate order for OPG. The Board finds the regulations are sufficiently

[108] Reply Argument page 203

explicit; the values related to income tax effects of timing differences and the revenue requirement impact of accounting and tax policy decisions must be accepted by the Board.

As a result, the Board accepts OPG's proposed accounting treatment and cost consequences of the $181M in deferred income taxes associated with the newly regulated assets as it relates to income tax decisions reflected in the liabilities as of December 31, 2013. The Board notes that the requirements of O. Reg. 53/05 are unique to OPG. Deferred taxes are not ordinarily included in the revenue requirement and there is no impact to the current test period revenue requirement as a result of this finding.

5 BRUCE LEASE – REVENUES AND COSTS
(Issue 7.3)

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 provide that the Board shall ensure that OPG recovers all the costs it incurs with respect to the Bruce nuclear facilities, and that any revenues it earns from the Bruce Lease in excess of costs will be used to offset the nuclear payment amounts.

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. Bruce revenues are derived from base and supplemental payments as set out in the Bruce Lease, used fuel storage and long term disposal services, low and intermediate waste management services, and support and maintenance services as set out in the Bruce Site Services Agreement. Costs include depreciation, which includes asset retirement costs, taxes, accretion, earnings/losses on nuclear segregated funds, the cost of used fuel storage and disposal, and the cost of waste management.

The Bruce Lease net revenues are forecast to be $39.7M in 2014 and $40.6M in 2015. If approved, these amounts would offset the nuclear revenue requirement. Variances are tracked in the Bruce Lease Net Revenues Variance Account.

SEC submitted that there is a $59M adjustment related to the adoption of USGAAP on January 1, 2011, that should not be permitted. SEC referred to interrogatory response Exh L-1.3-SEC-19 that showed OPG made a $59M one-time transitional adjustment on January 1, 2011 to comply with USGAAP lease accounting requirements. This treatment requires lease payments be recognized retrospectively on a straight line basis from the inception of a lease. SEC proposed that the $59M be credited to a deferral account. OPG argued that the adjustment was a required transition entry as part of the USGAAP opening balance sheet. OPG also argued that the SEC proposal would be inconsistent with Board direction that Bruce Lease net revenues be determined on a GAAP basis for non-regulated entities, and inconsistent with the settlement agreement in the USGAAP and Deferral and Variance Account proceeding, EB-2012-0002.

SEC submitted that it would be useful if the cost of generation from the Bruce nuclear facilities was provided to the Board on a regulatory basis in future cost of service proceedings for benchmarking purposes. OPG submitted that this proposal is inappropriate. The Board has already determined that Bruce nuclear facilities will not be treated as if they were regulated facilities. Further, OPG states that it is not privy to Bruce Power's cost of generation information.

Board Findings

The net amounts of the Bruce lease revenues and costs of $39.7M for 2014 and $40.6M for 2015 are approved.

OPG's adoption of USGAAP was reviewed in EB-2011-0432 and EB-2012-0002, and the Board agrees with OPG that the adjustment issue raised by SEC relating to USGAAP was dealt with as part of the settlement of the EB-2012-0002 proceeding. The Board also agrees that the previous cost of service decisions on Bruce Lease revenues and costs determined on the basis of GAPP for non-regulated entities are still appropriate.

The Board does not agree with the suggestion of SEC that OPG should file the cost of generation from the Bruce Generating Stations on a regulatory basis in future payment applications. The Bruce Generating Stations are neither regulated by this Board nor included as prescribed assets. The Board would not expect OPG to have information related to Bruce Power's costs and revenues.

6 NUCLEAR WASTE MANAGEMENT AND DECOMMISSIONING

(Issues 8.1 and 8.2)

OPG incurs liabilities for decommissioning its nuclear stations (including Bruce) and nuclear used fuel and low and intermediate level waste management.

The responsibility for funding these liabilities is described in the Ontario Nuclear Funds Agreement. This agreement requires OPG to establish two segregated funds:

- The used fuel fund
- The decommissioning fund – to fund the future cost of nuclear fixed asset removal, and low and intermediate level radioactive waste

In this proceeding OPG seeks recovery of $847.5M over the 2014 and 2015 test period for nuclear waste management and decommissioning for both prescribed nuclear and Bruce facilities.

The Ontario Nuclear Funds Agreement provides for the establishment of a reference plan for nuclear liabilities which must be updated every 5 years. The current approved Ontario Nuclear Funds Agreement reference plan became effective as of January 1, 2012. OPG's contributions to the used fuel fund and the decommissioning fund are determined based on the reference plan cost estimates.

The EB-2007-0905 decision approved a methodology for the recovery of nuclear liabilities that recognized a return on rate base associated with asset retirement costs for Pickering and Darlington. The methodology required that the return on the asset retirement cost be limited to the weighted average accretion rate, which is currently 5.37%. The portion of the rate base to which the accretion rate applies is equal to the lesser of (a) the forecast amount of the average unfunded nuclear liabilities related to the Pickering and Darlington facilities, and (b) the average unamortized asset retirement cost included in the fixed asset balances for Pickering and Darlington. In the previous two cost of service applications, and as proposed by OPG in the current application, (b) applies.

AMPCO observed that the decommissioning fund was overfunded by $624M at December 31, 2013, i.e. the value of the fund was higher than the balance required to meet all future obligations. The excess funding was shown as “Due to Province” in the audited financial statements.

The decommissioning fund has been overfunded in periods prior to Board regulation. AMPCO observed that in 2006, OPG recorded $190M from “Due to Province” credits to balance a $190M liability. AMPCO noted that the “Due to Province” cushion was used in 2006, 2007 and 2008.

During the oral component of this proceeding Board staff sought a calculation that reflected the application of the “Due to Province” amount to reduce unfunded nuclear liabilities, assuming a 53% allocation for the prescribed facilities. In completing the undertaking OPG stated that the “Due to Province” amount cannot be used in this manner. The resulting revenue requirement of the hypothetical scenario was higher than that proposed in OPG’s application as unfunded nuclear liabilities would be lower than the asset retirement costs. Under the Board-approved calculation methodology for nuclear liabilities cost recovery associated with the prescribed facilities, if the unfunded nuclear liability is lower than the unamortized asset retirement cost (ARC), cost recovery for the portion of the ARC amount is calculated using the higher weighted average cost of capital rate instead of the lower weighted average accretion rate.

AMPCO submitted that the calculations provided by OPG were misleading as the Bruce facilities were not considered. AMPCO revised the hypothetical calculations, allocating the $624M “Due to Province Amount” to the prescribed nuclear facilities and the Bruce facilities. AMPCO determined that the test period revenue requirement for nuclear liabilities should be reduced by $28.5M. OPG argued that it has properly reflected the requirements of the Ontario Nuclear Funds Agreement reference plan in the determination of nuclear liabilities and that AMPCO has failed to provide reasons why it disagrees with OPG’s interpretation. OPG’s treatment of the “Due to Province” amounts associated with the Bruce facilities is consistent with GAAP for non-regulated businesses.

AMPCO also observed that when the decommissioning fund is more than 120% overfunded, some of the excess can be transferred to the used fuel fund. AMPCO proposed a deferral account to record the amount the used fuel fund is entitled to. OPG argued that another account would require the Board to modify the scope of the existing Bruce Lease Net Revenues Variance Account.

AMPCO submitted that the Board should direct OPG to review its current nuclear liability methodology and any potential alternatives as part of the next payment amounts application.

Board Findings

The Board finds that the revenue requirement methodology approved by the Board in EB-2007-0905 continues to be appropriate for recovering nuclear liabilities. The Board does not find it necessary to direct a review of the current methodology at this time given the extensive Board review of the rate making options in EB-2007-0905.

The Board will not direct OPG to use the excess earnings in the Decommissioning and Used Fuel funds to decrease the revenue requirement by $28.5M as proposed by AMPCO as the funds are “Due to Province” as stipulated in the Ontario Nuclear Funds Agreement reference plan. The Board is satisfied that the current over funding position will not result in a cash withdrawal from the fund to the Province. In addition, given the long-term nature of the fund, it is appropriate for any periodic over earning to be retained within the fund to offset future potential under earning.

The Board will not approve the creation of a deferral account to record any excess earning in the decommissioning fund over 120%. Although any excess over 120% could be transferred to the used fuel fund, the Board does not find it necessary to create a regulatory asset when the reference plan is the source of record keeping and is updated every 5 years. The Board has no authority over the segregated funds or the reference plan for nuclear liabilities established by the Ontario Nuclear Funds Agreement.

The Board approves the recovery of $847.5M over the 2014 and 2015 test period for nuclear waste management and decommissioning for both prescribed nuclear and Bruce facilities.

7 CAPITAL STRUCTURE AND COST OF CAPITAL
(Issues 3.1 and 3.2)

7.1 Capital Structure

OPG did not apply for a change in capital structure in this proceeding. Rather, OPG proposed to use the same capital structure (53% debt and 47% equity) for all the regulated facilities, including the newly regulated hydroelectric facilities, which was originally approved in the first cost of service proceeding, EB-2007-0905, and again in the last cost of service proceeding, EB-2010-0008. In the current proceeding, OPG's proposed capital structure was supported by evidence (the "Foster report")[109] and expert testimony from Ms. Kathleen McShane of Foster Associates, Inc.

During the oral hearing, several parties challenged OPG's position that the capital structure was unchanged by the proposed $4 billion addition of the newly regulated hydroelectric facilities and Niagara Tunnel to rate base. These parties submitted that OPG's business risk has changed and that the equity thickness should be 42 to 43%.

SEC disagreed with Ms. McShane's view that the newly regulated hydroelectric facilities are more risky than the previously regulated hydroelectric facilities, but less risky than the nuclear facilities. SEC submitted that Ms. McShane has no independent knowledge of the business risks of the newly regulated hydroelectric facilities or the Niagara Tunnel, including First Nations issues, operating constraints or storage.

Noting that the Board concluded in EB-2007-0905 that the 47% equity thickness recommended by Drs. Kryzanowski and Roberts was appropriate, SEC submitted in the current proceeding that applying the methodology and parameters set out in Drs. Kryzanowski and Roberts' evidence in EB-2007-0905, namely 40% hydroelectric equity thickness and 50% nuclear equity thickness, to the proposed test period rate base would result in an overall equity thickness of 42.34%.

Board staff submitted that the Board did not approve the methodology of Drs. Kryzanowski and Roberts in EB-2007-0905, and that in the EB-2010-0008 proposal for technology specific cost of capital, Drs. Kryzanowski and Roberts revised the parameters to 43% hydroelectric equity thickness and 53% nuclear equity thickness.

[109] Exh L-3.1-SEC-24 Attachment 1

Should the Board accept the methodology and apply 43% equity thickness to all the hydroelectric facilities, Board staff submitted that the OPG equity thickness would be 45 to 46%.

OPG argued that none of the cost of capital experts that appear before the Board, including Drs. Kryzanowski and Roberts, have expertise in hydroelectric generation facilities. While the parties have challenged OPG's evidence and proposed reductions to equity thickness, none of the parties filed expert evidence to support their positions. OPG also argued that matters raised by some parties, e.g. comparisons with lower equity thickness for generators in other provinces by VECC, and the stand alone principle and 90% debt proposed by the Society, were previously addressed in EB-2007-0905. Further, as OPG is planning on spending more than $1.5 billion on the Darlington Refurbishment Project in the test period, OPG contends that its financial risk will increase in the test period.

Board Findings

In this application OPG did not request a change to its capital structure, claiming there had been no significant changes in the risks faced by its regulated asset portfolio that are not captured elsewhere in the application. While the application was filed in September 2013, no evidence was filed by OPG to substantiate this conclusion with respect to changes in risk until the interrogatory phase of the proceeding in March 2014.

The Foster report dealing with the capital structure and risk was not filed until March 19, 2014 in response to an interrogatory by SEC. The Board finds this late filing to be unfortunate, because the time between the report being publicly available and the date for intervenors to advise the Board of their intentions to file evidence was less than one week. The Board suspects that, had the Foster report been filed sooner, parties may have been in a better position to assess the merits of retaining their own expert on this matter. As it was, no alternative expert analysis was proffered and arguments by all parties were largely based on challenges to the Foster report.

The Board believes it would have been helpful to have had additional expert and independent evidence. The Board notes OPG's assessment that there had been no significant changes in risks was made before Foster Associates, Inc. was retained.[110] OPG appears to have made the initial assessment entirely on its own.

The Board cannot accept that business risk has not changed since the capital structure was last reviewed in 2010. Since that time, 48 additional hydroelectric facilities have been added to the inventory of prescribed assets, accounting for 12.4 TWh of energy forecast to be produced in 2014 and 12.5 TWh in 2015. These assets, together with the Niagara Tunnel which was brought into service in 2013, increase the proportionate share of rate base related to hydroelectric facilities from about half in 2010 to approximately two-thirds now. The relative business risk of hydroelectric generation versus nuclear has been accepted by the Board as being lower in previous proceedings,[111] even though setting the capital structure on a technology specific basis has not. The critical question therefore becomes whether business risk has changed in a significant enough way to warrant a change in capital structure, and in which direction is this change – lower or higher risk?

The Board finds that including additional hydroelectric units to the roster of prescribed assets lowers the business risk for several reasons. Subject to Board approval through this proceeding, these additional assets will be subject to treatment under a number of previously approved Board deferral and variance accounts for a host of variables, all of which reduce business risk. Since the equity component was first set, a new pension variance account has been approved by the Board. This variance account decreases OPG's forecast risk associated with pension and OPEB costs. The proportion of regulated assets between hydroelectric and nuclear generation has changed, with hydroelectric facilities now having a much larger share of the generating capacity of OPG than previously. It was acknowledged by OPG's consultant that hydroelectric facilities have lower risk than nuclear.[112] The new assets being added to rate base have long remaining service lives (average of 58 years for the newly prescribed assets[113]) and 95 years for the Niagara Tunnel. As long as there is rate regulation, these assets will produce power and revenue certainty until the end of their useful lives.

The Board considered the Foster report and makes the following observations.

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[110] Application is dated September 27th, 2013 while contract commencement date is September 30th, 2013. (Undertaking J10.2)
[111] Decision with Reasons, EB-2010-0008, page 116
[112] Tr Vol 10 page 30
[113] Undertaking J12.3

- No independent analysis was undertaken of the operating costs and lives of the newly prescribed assets. The consultant's opinion was based on discussions with OPG staff only. While information obtained from operating personnel is an important component to assessing risk, the lack of independent knowledge of the circumstances of OPG's newly regulated hydroelectric operations is a concern.
- The opinion that the newly regulated assets have increased risk due to their location in Northern Ontario within First Nations communities and their traditional ways of life was not substantiated by fact. It appears this was conjecture on the part of the consultant based on conversations with OPG management.
- There was no evidence as to the impact of a change in equity thickness on the credit metrics.

OPG raised various other arguments with respect to the need for at least the same, or higher, equity thickness. One of these arguments was that there is a greater risk associated with the future move to incentive regulation. The Board does not accept that moving to incentive regulation significantly increases risk to the entity such that the capital structure should be reset, and has not done so for any of the other companies that it regulates. For example, the Board set the capital structure for all electricity distributors at a 40% equity to debt ratio in December 2006. As new incentive regulation models for electricity distributors evolved in 2008[114] and 2012[115], this capital structure was not revisited. Similarly, the capital structure for the natural gas distributors did not change as a result of moving to a long-term incentive regulatory mechanism for the setting of rates for these distributors. In addition, OPG is not actually being moved to incentive regulation in the current proceeding, and any potential changes to business risk this may entail could be considered in the incentive regulation proceeding. The Board therefore is not persuaded by the comments made by OPG and its consultant that the future move to an incentive regulatory mechanism for OPG increases business risk such that a higher equity thickness should be considered.

Instead, the Board has determined that business risk has changed for this payment setting period, and that the business risk is reduced. The business risk is reduced because of the addition of significant hydroelectric assets to rate base, which are less risky than nuclear assets.[116] The Board finds that a more appropriate equity thickness

[114] Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, July 14, 2008
[115] Report of the Board Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach, October 18, 2012
[116] Exh L-3.1-SEC-24, Attachment 1 page 23, Tr Vol 10 page 30

is 45%. This equity thickness is still considerably higher than any other entity regulated by the Board.

The Board does not accept the Society's argument that due to the change in the energy environment that the well accepted principles of a stand-alone entity should be abandoned and also that OPG can have up to a 90% debt operating structure due to its ownership structure. The Board has previously commented on the validity of the stand-alone principle and as neither of these issues was explored in sufficient detail through cross-examination or the production of independent expert evidence, the Board sees no justification for such a major change.[117]

In reaching this conclusion the Board was mindful of the Fair Return Standard as articulated by the courts, and the need to observe the requirements of consideration of comparable investment, financial integrity and capital attraction. However, the Fair Return Standard is sufficiently broad to allow a regulator to apply informed judgment and discretion in the determination of a rate regulated entity's cost of capital. The Board believes that a reduction to equity thickness is based on the evidence in this case, the Board's best judgment and is a reasonable outcome.

As a result of its review, the Board finds that the capital structure should be based on 45% equity and 55% debt.

7.2 Return on Equity

OPG's current proposal is to apply 9.36%, the Board's ROE for 2014 cost of service applications, for 2014 and 9.53% for 2015 based on Global Insights data from September 2013.

In the event that the Board's ROE for 2015 cost of service applications was available at the time of the payment order, Board staff submitted that the Board's ROE, based on more recent *Consensus Forecasts*, be used instead of the 9.53% proposed by OPG based on Global Insights data from September 2013.

OPG replied that Board staff's proposal would involve data after the close of record and would be a departure from the methodology used for setting the ROE in the second

[117] Decision with Reasons, EB-2007-0905, pages 137–142

year of the test period as adopted by the Board in the previous payment amounts decisions.

In addition to proposing a 90% debt structure, the Society submitted that the allowed return should be the social discount rate. OPG argued that the social discount rate was not addressed in this proceeding.

Return on Equity for Newly Regulated Hydroelectric Facilities

In the current application, OPG proposes to add $2.5 billion to rate base in relation to the newly regulated hydroelectric facilities.

Environmental Defence did not object to the addition, referring to the requirements of O. Reg. 53/05, however, Environmental Defence submitted that 50 to 60% of the addition is related to the revaluation of assets process that occurred when OPG was created as one of the successors to Ontario Hydro. Environmental Defence submitted that this portion of OPG’s rate base should not earn the ROE, but instead should attract a return based on long-term debt. Environmental Defence also submitted that the Board should consider this treatment for the previously regulated hydroelectric facilities in the next proceeding.

OPG argued that “a package of assets” was sold to OPG in exchange for certain debt and equity amounts as part of the restructuring process. This was done to make OPG a viable operation on a stand-alone basis. Further, Environmental Defence’s submission is inconsistent with the Board’s treatment of the previously regulated hydroelectric facilities in the first proceeding.

CME submitted that the Board should consider the cost of capital supporting the newly regulated hydroelectric assets at December 31, 2013. The newly regulated hydroelectric facilities, on a stand-alone basis at December 31, 2013, were producing an actual loss from operations. In CME’s view, the cost of capital supporting the newly regulated hydroelectric assets should be the interest rate that applies to “stranded debt” which CME estimates to be 5.9%.

OPG argued that the newly regulated hydroelectric facilities, prior to becoming regulated, were being financed by the debt and equity of the consolidated OPG. The fact that the newly regulated hydroelectric facilities were not earning their cost of capital on December 31, 2013 does not mean that their cost of capital was equal to the cost of debt. Further, OPG's 2013 audited financial statements do not contain an impairment charge for these assets.

Board Findings

With respect to Return on Equity, the Board's Return on Equity for 2014, 9.36% will apply for the 2014 test year. As the Board's 2015 cost of capital parameters will be available when the payment order process for the current proceeding is underway, the Board's Return on Equity for 2015 will apply for the 2015 test year.

The Board notes that the revaluation of the newly regulated assets was undertaken at the time of Ontario Hydro restructuring about 15 years ago. As a result of this restructuring, Environmental Defence proposes to have the newly regulated assets earn a return based on long-term debt. The Board finds this inappropriate and inconsistent with prior Board Decisions, e.g., EB-2007-0905 when the previously regulated hydroelectric facilities were first regulated by the Board.

The Board has reviewed CME's submission and has determined that the Return on Equity determined above will apply to all regulated assets.

7.3 Short Term Debt and Long Term Debt

OPG proposes, for Board approval, the following debt rates for the test period.

	2014	2015
Long-term Debt	4.85%	4.86%
Short-term Debt	1.87%	2.89%

There were no opposing submissions filed.

The Board accepts that the long-term and short-term debt rates proposed by OPG are appropriate. The final approved debt costs will be adjusted by the rate base and capital structure findings found elsewhere in this Decision.

8 DEFERRAL AND VARIANCE ACCOUNTS

There are currently 15 deferral and variance accounts for OPG that were established pursuant to O. Reg. 53/05 or Board decisions.

In the EB-2012-0002 USGAAP and Deferral and Variance Account proceeding, the Board accepted the settlement proposal of the parties. The audited balances as of December 31, 2012 in the deferral and variance accounts were approved for disposition, except for four accounts. The EB-2012-0002 proceeding established payment riders for 2013 and 2014. The 2014 riders are $2.02/MWh for the previously regulated hydroelectric facilities and $4.18/MWh for the nuclear facilities.

8.1 Clearance of Accounts in the Current Proceeding
(Issues 9.1, 9.2, 9.3 and 9.4)

In the current proceeding, OPG seeks clearance of the 2013 year end balances for the following four accounts in riders starting January 1, 2015.

- Hydroelectric Incentive Mechanism Variance Account
- Hydroelectric Surplus Baseload Generation Variance Account
- Capacity Refurbishment Variance Account – Hydroelectric and Nuclear (OPG is not seeking clearance of the nuclear non-capital cost account additions)
- Nuclear Development Variance Account

The audited 2013 year-end balances for the hydroelectric accounts listed above is $126.9M, however, OPG proposes to clear the capacity refurbishment variance hydroelectric sub-account over 2 years. The 2015 hydroelectric amortization amount proposed is $70.6M. The audited 2013 year-end balance for the nuclear accounts listed above is $62.2M.

Board staff and LPMA had no concerns with the balances in the four accounts for which OPG seeks disposition in this proceeding. LPMA submitted that the recovery period could be extended if mitigation is required. Board staff submitted that the right to re-examine the accounts that are not being disposed in this proceeding should be reserved for the future application that will dispose of them. In reply, OPG accepted that these accounts should be re-examined when the balances are disposed.

SEC submitted that there is no basis on which to approve the addition of several Darlington Refurbishment campus plan projects to rate base, e.g. the Darlington Operations Support Building refurbishment. SEC submitted it would be reasonable to add this to the Capacity Refurbishment Variance Account, so that when proper evidence is filed in a future proceeding, it can be added to rate base at that time. OPG argued that there is no basis to SEC's objections and no reason to conclude that the balance in the capacity refurbishment account is incorrect.

The 2013 year-end balance in surplus baseload generation account is $19.2M. The 2011-2013 unintended benefit to OPG of the interaction between surplus baseload generation and the hydroelectric incentive mechanism has been determined to be $6.8M in undertaking J4.7. Both CME and VECC submitted that the $6.8M should be returned to ratepayers. OPG argued that the proposed adjustment is improper because it amounts to retroactive ratemaking. The Board's EB-2010-0008 decision established the terms for account entries and no party argued that the balances in the accounts were not accurately calculated.

Board Findings

The Board approves disposition of the audited December 31, 2013 balances in the four variance accounts. The Board does not find it necessary to mitigate the rate impact for the Capacity Refurbishment Variance Account hydroelectric sub-account with a 2 year amortization period as the account balance is $112.7M. As proposed by OPG, the riders shall commence on January 1, 2015. The riders will end on December 31, 2015.

The Board will not adjust the balance in the Hydroelectric Surplus Baseload Generation Variance Account to eliminate the unintended benefit realized by OPG, as proposed by CME and VECC. The Board does not find it appropriate to alter the terms and calculation approved in EB-2010-0008 to accommodate new information that was not available at the time of the Board's decision. Changing the December 31, 2013 account balance would not be retroactive ratemaking, as any variance account balance is subject to change prior to final disposition by the Board. However, the proposed adjustment would be improper as this was not addressed in the Board's EB-2010-0008 decision.

In addition, the Board will not require OPG to make additional entries to the Capacity Refurbishment Variance Account. The Board has approved the rate base additions related to the Darlington Refurbishment campus plan projects as proposed by OPG, and therefore, there is no residual unapproved balance to transfer to the variance account as proposed by SEC.

8.2 Continuation of Accounts and New Accounts

(Issues 9.5, 9.7, 9.8. 9.9)

OPG requested the continuation of the following accounts:

- Hydroelectric Water Conditions Variance Account
- Ancillary Services Net Revenue Variance Account – Hydroelectric and Nuclear Sub-Accounts
- Hydroelectric Incentive Mechanism Variance Account
- Hydroelectric Surplus Baseload Generation Variance Account
- Income and Other Taxes Variance Account
- Tax Loss Variance Account
- Capacity Refurbishment Variance Account
- Pension and OPEB Cost Variance Account
- Impact for USGAAP Deferral Account
- Hydroelectric Deferral and Variance Over/Under Recovery Variance Account
- Nuclear Liability Deferral Account
- Nuclear Development Variance Account
- Bruce Lease Net Revenues Variance Account – Derivative and Non-Derivative Sub-Accounts
- Pickering Life Extension Depreciation Variance Account
- Nuclear Deferral and Variance Over/Under Recovery Variance Account

The total year end 2013 debit balance for all accounts is $217.3M for the previously regulated hydroelectric facilities and $1,478.4M for the nuclear facilities. OPG plans to seek clearance of the December 31, 2014 balances in all its deferral and variance accounts through a separate application to be filed in 2014.

As set out in EB-2012-0002, OPG will terminate the Tax Loss Variance Account and the Impact for USGAAP Deferral Account on December 31, 2014, with any remaining balance transferred to the over/under variance accounts. OPG has proposed an enhanced hydroelectric incentive mechanism in the current proceeding that eliminates the need for future additions to the Hydroelectric Incentive Mechanism Variance Account.

OPG has proposed to extend the application of four variance accounts specific to hydroelectric operations and three common cost variance accounts (i.e., accounts that impact both hydroelectric and nuclear operations) to its newly regulated hydroelectric operations. The newly regulated hydroelectric accounts would be subaccounts of existing accounts. Entries to the accounts would commence on the effective date of the payment amounts.

In the EB-2012-0002 settlement proposal, accepted by the Board, no interest was to be applied to the balance in the Pension and OPEB Cost Variance Account for the 2 year period ending December 31, 2014. OPG proposes that interest will resume on January 1, 2015. Board staff submitted that the variances in the Pension and OPEB Cost Variance Account have been actuarially determined and that interest should not apply to be consistent with other decisions of the Board. OPG did not reply on this matter.

No parties objected to OPG’s proposal to extend existing accounts to include the newly regulated hydroelectric facilities.

Board staff and other parties have supported the continuation of the current hydroelectric incentive mechanism, and keeping the hydroelectric incentive mechanism variance account open to additions. Board staff and other parties also submitted that the Hydroelectric Incentive Mechanism Variance Account should also apply to the incentive mechanism revenue related to the newly regulated hydroelectric facilities. OPG agreed that it would be appropriate to continue additions to the account if the Board decides to retain the current hydroelectric incentive mechanism. However, the current variance account is asymmetrical. If OPG fails to earn its half of the incentive net revenues, it owns the loss, whereas ratepayers are fully protected. OPG submitted that the account should act both ways.

If the Board approves a cash basis for pension and OPEB, Board staff submitted that it would be reasonable for the Board to approve a variance account for differences in forecast cash payments included in revenue requirement and actual cash payments. It would also be reasonable that carrying charges would apply to the cash variance. OPG has serious concerns with respect to cash basis determination for pension and OPEB. However, if the Board proceeds with this methodology, the account would be required.

Board staff submitted that Ministry of Natural Resources approval of a 10 year gross revenue charge holiday for the Niagara Tunnel Project is highly likely, however, that holiday is not reflected in the current application. Board staff submitted that an account should be set up to capture the gross revenue charge costs for return to ratepayers. OPG had no objection to this submission.

In its submission on nuclear liabilities, AMPCO proposed a deferral account to record 50% of an excess of 120% of the decommissioning fund balance. SEC submitted that there is a $59M adjustment related to the Bruce Lease and the adoption of USGAAP on January 1, 2011, that should not be permitted. SEC proposed that the $59M be credited to a deferral account. OPG does not support either of these accounts, arguing that there is no basis for making the adjustments.

Board Findings

The Board approves the continuation of existing deferral and variance accounts as proposed by OPG, with two exceptions.

First, the Board directs OPG to maintain the Hydroelectric Incentive Mechanism Variance Account as the Board has rejected the alternative enhanced hydroelectric incentive mechanism proposal. OPG will maintain the current mechanism with the one variation that eliminates the unintended benefit to OPG. As a result, the variance account will also be maintained to track any revenues earned over the incentive thresholds of $78M in 2014 and $96M in 2015. The Board will maintain the account's asymmetrical structure and purpose, and extend the account's application to include the newly regulated hydroelectric assets.

Second, the Board rejects OPG's proposal to accrue interest on the balance in the Pension and OPEB Variance Account after December 31, 2014. The Board finds no compelling reason to change OPG's current practice of maintaining the balance without interest, which was part of the EB-2012-0002 settlement proposal approved by the Board.

Regarding the creation of new accounts, the Board accepts OPG's proposal to extend seven variance accounts to the newly regulated hydroelectric assets. The Board has included an eighth account, the Hydroelectric Incentive Mechanism Variance Account as previously approved. New sub accounts will need to be created for the newly regulated assets, extending the applicability of the existing variance accounts. Entries to the accounts will commence on the effective date of the payment amounts for the newly regulated hydroelectric facilities.

In addition, the Board approves the creation of a variance account to track any variance in the gross revenue charge forecast to be paid for the Niagara Tunnel Project. A charge is forecast and included in the 2014 and 2015 payment amounts, yet the approval is outstanding for a 10-year gross revenue charge exemption for the Niagara Tunnel Project. The new account will be called the Gross Revenue Charge Variance Account.

As noted in the Pension and OPEB Accounting section of this Decision, the Board approves a new variance account to track any contributions that differ from the minimum cash requirements, as included in the 2014 and 2015 payment amounts. Interest will apply to this variance account given that it relates to cash payments. This new account will be called the Pension & OPEB Cash Payment Variance Account.

In addition, the Board has approved the establishment of a new deferral account to track the differential between the accrued and cash valuations for pensions and OPEBs. The Board does not approve the accrual of interest on the deferral account balance given that it tracks non-cash items. The new account will be called the Pension & OPEB Cash Versus Accrual Differential Deferral Account.

As proposed by OPG, the Tax Loss Variance Account and the Impact for USGAAP Deferral Account will be terminated effective December 31, 2014.

8.3 Future Disposition of Accounts
(Issue 9.6)

As noted previously, OPG plans to seek clearance of the December 31, 2014 balances in all its deferral and variance accounts through a separate application to be filed in 2014.

Board staff observed that the current proceeding is the third proceeding in which OPG has filed for clearance of deferral and variance accounts on the basis of forecasts with audited account balances filed later in the proceeding. No other utilities do this and this type of filing creates inefficiency as initial assessments are repeated when the audited balances are filed. Board staff suggested that the Board may wish to consider whether it will permit OPG to continue to file on the basis of estimates. Board staff also submitted that OPG did not provide sufficient rationale with its application, as filed on September 27, 2013, to limit clearance to only four deferral and variance accounts. The Board may wish to consider that the most effective and efficient means of assessing deferral and variance account balances is to do so at the time of also assessing a utility's costs of service, given the links between certain of the accounts and the revenue requirement.

OPG replied that the efficiency impact of filing deferral and variance account balances on a forecast basis is insignificant. Limiting account clearance to 4 accounts was sensible and appropriate given the size, duration and complexity of the current application. OPG stated that its approach made the current case more manageable.

LPMA submitted that the Board could consider denying additional carrying costs for the accounts OPG has proposed not to clear in this proceeding. OPG replied that this matter was not put to an OPG witness. The submission is punitive and should be rejected.

Board Findings

The Board does not endorse OPG's decision to bifurcate its cost of service issues into two separate proceedings, deferring its application for disposition of deferral and variance accounts to a later date. The Board accepted OPG's separate application in the EB-2012-0002 proceeding application but the Board did not intend to endorse a new, unique rate-setting approach for OPG. It is not a common practice of any other entity regulated by the Board to apply for a separate proceeding to dispose of deferral and variance accounts, other than when the entity is under a long-term incentive regulation method for rate-setting. This is not the case for OPG at this time. The Board does not accept OPG's statement that it proposed this two-step approach in order to manage and expedite the review of other issues in the application. With all of the complex issues included in this application, adding the clearance of deferral and variance accounts would not have added significant time or burden to this proceeding.

As a result of OPG deferring its application for disposition of deferral and variance accounts, the Board is unable to render a decision on the need for rate mitigation in 2014 and 2015, based on the overall bill impact resulting from OPG's operations. This creates a difficult situation for ratepayers who will not understand the full impact on payment amounts for 2014 and 2015 until the second application is completed. Based on the evidence filed, the account balances to be cleared in a second application will be significant.

While the Board has approved OPG's proposal to limit the clearance of deferral and variance accounts in this proceeding to the four accounts put forth by OPG, it is the Board's expectation that going forward, all accounts should be reviewed and disposed of in a cost of service proceeding unless there is a compelling reason to not do so. The Board agrees with Board staff that the optimal time to review all accounts is at the time of a cost of service review, based on the most recently audited account balances rather than forecasts. Any mitigation measures that may be required can also be considered at that time. This approach is consistent with the treatment of deferral and variance accounts for electricity distributors.

9 REPORTING AND RECORD KEEPING REQUIREMENTS (Issue 10.1)

Board staff observed that OPG has in several instances made changes to regulatory accounting during the period outside of its payment applications. The changes affect the accounting basis on which the rates were approved. As an example, Board staff noted that OPG extended the useful life of Pickering effective December 31, 2012, resulting in a decrease in depreciation of $47M annually.

Board staff submitted that OPG should be directed to first seek Board approval through an accounting order that outlines the nature of the change and the impact. Board staff suggested that a revenue requirement threshold of $20M be used, for accounting changes, whether arising from a single or multiple transactions, and noted that the EB-2012-0002 has a similar provision for nuclear liability accounting changes that have a revenue requirement impact of $10M or more annually. SEC did not agree with a threshold as any change could be applicable for three years before rates are changed.

OPG submitted that a requirement to seek Board approval for accounting changes would be a burden for both OPG and the Board. However, OPG concluded that the Board staff submission is really focused on accounting changes that impact depreciation expense and the related impact on accumulated depreciation and rate base. OPG replied that it would support the expansion of the nuclear liability requirement set out in EB-2012-0002 to include impacts of changes in station useful lives on non-asset retirement cost component of nuclear fixed assets reflected in rate base. This requirement would capture future changes similar to the $47M Pickering depreciation expense example.

If the Board is inclined to require accounting orders for a broader range of accounting matters, OPG submitted that a $20M threshold would be more appropriate to keep the requirement manageable.

Board Findings

The Board will not require OPG to seek prior Board approval of all accounting changes made between payment amount applications. The Board finds accounting decisions should continue to be made by OPG's management. The Board's responsibility is to approve the future recovery of expenses through the determination of OPG's payment amounts, based on the evidence available. At that time, the Board will opine on the proposed, underlying accounting treatment by OPG.

Upon application for new payment amounts and where an accounting change has occurred, OPG must include historical information that enables the comparison between years of expenses and impact on elements which form part of the payment calculation. This will involve the preparation of continuity schedules showing the impact of the accounting change such that year over year comparisons are transparent and readily apparent. The Board notes that this is not a new requirement, as the OPG filing guidelines (EB-2011-0286) already stipulate that changes in accounting methodologies that affect any of the historic, bridge or test years must be provided.

OPG also has nuclear liabilities reporting requirements as set out in EB-2012-0002.

> OPG shall file an accounting order application with the Board and provide notice to intervenors of record in EB-2012-0002 if, other than as a result of an Ontario Nuclear Funds Agreement Reference Plan update, OPG proposes to effect an accounting change impacting the calculation of its Nuclear Liabilities that results in a revenue requirement impact for the prescribed facilities that is neither reflected in the current or proposed payment amounts nor recorded in the Nuclear Liability Deferral Account (including, without limitation, any change in the useful lives of any asset for depreciation or amortization purposes). OPG shall not be required to apply for such accounting orders if the impact on the annualized revenue requirement impact for the prescribed facilities is less than $10M.[118]

In this proceeding, OPG has agreed to expand these requirements to include impacts of changes in station useful lives on the non-asset retirement cost component of nuclear fixed assets reflected in rate base. As a result, the Board approves this extension of the nuclear reporting requirements and requires OPG to provide notice to any additional intervenors of record in this proceeding, EB-2013-0321.

[118] Payment Amounts Order, EB-2012-0002, April 13, 2013

10 METHODOLOGIES FOR SETTING PAYMENT AMOUNTS

10.1 Incentive Regulation

(Issue 11.1)

O. Reg. 53/05 empowers the Board to establish the “form, methodology, assumptions and calculations” to be used in setting payment amounts for OPG’s prescribed generation assets. While the current proceeding is the third cost of service proceeding, the Board has indicated its intention to “implement an incentive regulation formula for OPG when it is satisfied that the base payment provides a robust starting point for that formula.”[119] The Board has communicated its intention in the report, *A Regulatory Methodology for Setting Payment Amounts for the Prescribed Generation Assets of Ontario Power Generation Inc.*, EB-2006-0064, issued on November 30, 2006, the EB-2010-0008 Decision with Reasons issued on March 10, 2011 and most recently, the *Report of the Board on Incentive Rate-making for Ontario Power Generation’s Prescribed Generation Asset*, EB-2012-0340, issued on March 28, 2013.

On the basis of a consultative process, the EB-2012-0340 report set out a timeline to establish incentive regulation for the hydroelectric business and multi-year cost of service for the nuclear business assuming a 2014-2015 cost of service application filing in mid-2013. As the current application was not filed until September 2013 and a decision is not expected until late 2014, Board staff has submitted that working groups would not be initiated until early 2015, at the earliest. It would be many months before a Board report based on the working group’s analysis and recommendations could be issued. Board staff submitted that it is unlikely that incentive regulation will be implemented prior to the filing of an application for 2016 payment amounts.

In reply, OPG suggested that the working groups could be initiated in November 2014. OPG has contracted with London Economics Inc. to conduct the independent hydroelectric study requested by the Board in EB-2010-0008. OPG proposed that the working groups could review that study, and that the study and any working group materials could be made public once the decision in the current proceeding was issued.

[119] 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

Notwithstanding the Board's position, CCC has submitted that OPG may not be the type of entity that can be regulated through an incentive regulation model. CCC submitted that the working groups should consider whether incentive regulation is appropriate for OPG as a threshold issue.

LPMA submitted that incentive regulation for the hydroelectric facilities may be premature as there is no history related to the newly regulated hydroelectric facilities under regulation. The Society submitted that "incentive rates are an implicit acknowledgement of a lack of expertise."[120]

Board Findings

The Board has indicated in previous decisions its objective of having OPG payment amounts set on an incentive regulation methodology ("IRM"). The Board continues to believe that a long-term, properly designed IRM has the potential to lead to operational efficiencies and innovation, and thus lower electricity costs. Progress in this direction of an IRM to payment setting has been made, with the issuance of the Board's Report on *Incentive Regulation for Ontario Power Generation's Prescribed Assets* (EB-2012-0340).

OPG shall file the London Economics Inc. study immediately upon completion. Recommendations on the details of the IRM are to be established through a working group, comprised of OPG, Board staff and stakeholders. The Board sees no reason for delay. The Board remains committed to setting payment amounts for the nuclear assets under IRM as well. However, the Board will wait until the Darlington Refurbishment Project is further advanced before issuing further direction in this regard.

10.2 Payment Design and Mitigation

(Issue 11.2 and 11.3)

OPG has determined that the payment amount increase sought in the current application, including the newly regulated hydroelectric facilities, is 23.4%. The estimated bill impact is an increase of $5.31 per month on the bill of a typical residential consumer. As the bill impact is less than 10%, OPG has not proposed any mitigation.

[120] Society Submission page 11

Board staff noted that the 23.4% increase in payment amounts is the largest increase OPG has proposed in a cost of service application. In addition, OPG will be seeking to dispose of further significant balances by way of a stand-alone deferral and variance account application shortly following this proceeding. Board staff submitted that some consideration of mitigation was appropriate.

The newly regulated hydroelectric facilities currently receive payment for generation based entirely on the Hourly Ontario Energy Price (“HOEP”). OPG seeks a payment amount of $47.57/MWh, which is a 59% increase over the $30/MWh proxy for HOEP that OPG has assumed for this application. Board staff submitted that the Board could consider approving half of the increase for the 2014 test year, and the full increase for the 2015 test year. These 2014 payment amounts would be higher than the 2009-2013 historical HOEP. SEC disagreed with the Board staff proposal. SEC submitted that the intent of O. Reg. 53/05 is that the newly regulated hydroelectric facilities will move to a “normal” regulated rate effective July 1, 2014.

OPG argued that the Board staff proposal without a deferral account is really the confiscation of prudently incurred costs that OPG is legally entitled to recover. The proposal is contrary to expert reports filed in other Board proceedings that refer to phase-in of rates and deferred amounts recognized as regulatory assets, and implementation such that there is no harm to the utility.

Board Findings

The design of the regulated hydroelectric and nuclear payment amounts is the same as had been established through the previous two payment amount proceedings, and no changes have been proposed. The Board accepts the existing payment amounts design for 2014 and 2015.

No mitigation of payment amount increases is approved in this Decision. It should be noted that the total bill impact to ratepayers over the test period will be dependent upon another application and proceeding related to disposition of OPG’s deferral and variance account balances as at December 31, 2014, and which will likely seek rate riders starting in 2015 to account for the clearance of these deferral and variance accounts. The need for mitigation should be an issue in this subsequent proceeding, in the context of OPG’s total bill impact.

11 IMPLEMENTATION
(Issue 12.1)

OPG requests an effective date of January 1, 2014 in respect of the previously regulated hydroelectric and nuclear facilities, and an effective date of July 1, 2014 for the newly regulated hydroelectric facilities. With respect to the newly regulated hydroelectric facilities, section 6(2)11 of O. Reg. 53/05 states the following:

> 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.

At OPG's request, the Board issued an interim payment amounts order on December 17, 2013, declaring the payment amounts for the previously regulated hydroelectric and nuclear facilities interim as of January 1, 2014, and the newly regulated hydroelectric facilities as of July 1, 2014.

OPG argues that: "having declared current payment amounts interim as of the dates set out above, the OEB is obliged to make the payment amounts it determines to be just and reasonable after a review of the application effective from those dates. The time taken to process and review OPG's application is legally irrelevant."[121] In its Argument-in-Chief, OPG relied on *Bell Canada v. Canada (Canadian Radio-Television and Telecommunications Commission)*, [1989] 1 S.C.R. 1722 ("Bell"). The Bell decision establishes that the Board has the power to retrospectively set the implementation date of the decision back to the date that payment amounts were declared interim. OPG argues that this power, when coupled with the requirement that the Board must ensure that at all times payment amounts are just and reasonable, amounts to a legal requirement that the Board set the effective date of the order back to the date payment amounts were declared interim.

With respect to the newly regulated hydroelectric facilities, CME submitted that section 6(2)11 of O. Reg. 53/05 cannot override the Board's powers to set just and reasonable

[121] Argument-in-Chief, page 146.

rates. The overall impact on consumers of OPG's proposals needs to be considered in the context of the retroactivity component of the relief OPG seeks. CME submitted that none of the retroactive amounts should be recoverable from ratepayers. OPG disagreed with CME's submission observing that there is no conflict between the Act and the regulation as the Act provides for combined operation of section 78.1(2) and the regulation.

Board staff argued that the Bell case gives the Board the ability to retrospectively adjust final rate orders back to the date the interim order was issued, but it does not require the Board to do so.

Several other parties disagreed with OPG and proposed a range of different effective dates for the respective payment orders. SEC and CCC argued that the timing of the filing of the application was entirely within OPG's control. SEC pointed to the extensive updates that were filed by OPG throughout the proceeding, which resulted in additional delay. These parties submitted the effective date for the previously regulated assets should be the month following the date of the payment order. Board staff submitted that July 1, 2014 should be the effective date for all payment amounts as it was the earliest possible date a decision and payment order could have been completed based on a September 27, 2013 filing.

Board Findings

The Law Respecting Interim Orders

The Board does not accept that there is a legal requirement that it set the effective date of its final orders to the date that rates were declared interim. OPG's view is not supported by the wording of the legislation, the case law, nor the Board's practice.

The Board's power to set interim rates derives from section 21(7) of the Act: "[t]he Board may make interim orders pending the final disposition of a matter before it." As the use of the word "may" reveals, there is no requirement that the Board issue interim rate orders at all. As the decision to issue an interim order is discretionary, it follows that any decision to draw the effective date of the final payments order back to the date of the interim order is also discretionary. Nothing in the legislation suggests that the issuance of an interim order in any way ties the Board's hands with respect to the effective date of the final order. If the Legislature had intended that the Board be required to match the effective date of an order to the date interim rates were declared, it would have written that into the legislation. This was not done, and the Legislature has instead left the matter to the Board's discretion.

The Bell decision referred to by OPG establishes that interim rate orders give the Board the *ability* to retrospectively alter rates (or in this case payment amounts) back to the date the interim order was issued. As the Board stated in its decision in EB-2005-0361, nowhere does Bell state, or even suggest, that the Board is *required* to do so. Instead, the language of Bell suggests a permissive or discretionary approach. The Court stated: "It is inherent in the nature of interim orders that their effect as well as any discrepancy between the interim order and the final order <u>may</u> be reviewed and remedied by the final order."[122] The Bell decision does not support OPG's conclusion that the Board is legally required to align the effective date to the interim date, and OPG has not pointed to any other cases which support its position.

The Board issued the interim payment amounts order on December 17, 2013 at OPG's request and without any input from any other party. The Board was clear that by declaring rates interim it was not committing itself to ultimately setting the effective date of the final order to match the interim date: "This determination [i.e. the order declaring payment amounts interim] is made without prejudice to the Board's ultimate decision on OPG's application, and should not be construed as predictive, in any way whatsoever, of the Board's final determination with regards to the effective date for OPG's payment amounts arising from this application."[123]

Although OPG questioned in final argument whether the Board even has the ability to set an effective date to some date other than the interim date, it made no comment on this point when it made its request for interim payment amounts, nor when the interim order was issued. Given that the sentence quoted above is commonly included in the Board's interim orders, the Board is surprised to hear for the first time in OPG's final argument that OPG feels the Board lacks this authority. The very reason that the Board generally issues interim orders without seeking submissions from parties is that parties will be given the opportunity to ask questions and make submissions about the effective date of the final order throughout the hearing process. If the Board is legally required to match the effective date to the interim date, as OPG argues, then the issuance of the interim order without process arguably represents a breach of the "right to be heard"

[122] Bell, page 1752 (emphasis added)
[123] Interim Payment Amounts Order, December 17, 2013

principle. In the current case, ratepayer groups would be responsible for hundreds of millions of dollars in costs relating to the "interim" period without being afforded any opportunity for comment at all.

OPG argues that the Board has an obligation to ensure that rates are just and reasonable at all times. As a general statement, this is true. However, the Board's power to consider and set what makes a just and reasonable rate is very broad and allows significant flexibility. The obligation to ensure that rates are always just and reasonable does not mean that the Board must examine and adjust a utility's rates on a constant basis. Most utility's rates are set on a forecast basis, for example, and invariably these forecasts turn out to be inaccurate to some extent. Absent extraordinary circumstances, the Board does not intervene to adjust rates simply because actual costs or revenues are different from what was forecast – even though the Board has the power to do so. In other words, there is a measure of "wiggle room" in a just and reasonable rate. Just and reasonable rates can fall within a range, and there is no defined line past which rates immediately become "unreasonable". Indeed, under incentive regulation rates are deliberately de-coupled from a utility's actual costs. The Board therefore does not agree with OPG's argument that the requirement to ensure just and reasonable rates at all times leads to an automatic requirement to match the effective date with the date interim rates were set.

Effective date for the Nuclear and Previously Regulated Hydroelectric Payment Amounts

The Board has determined that the effective date for the payment amounts for the nuclear and previously regulated hydroelectric facilities will be November 1, 2014. The Board is not prepared to accept the January 1, 2014 effective date proposed by OPG as it is contrary to the Board's long-standing practice of setting rates on a forecast (i.e. forward test year) basis.

The Board's general practice with respect to the effective date of its orders is that the final rate becomes effective at the conclusion of the proceeding. This practice is predicated on a forecast test year which establishes rates going forward, not retrospectively. Going forward, the utility knows how much money it has available to spend and the ratepayer knows how much it is going to cost to use electricity in order to make consumption decisions. The forecast test year enables both the utility and the ratepayer to make informed decisions based on approved rates. The forecast test year is a pillar in rate setting and the Board's practice must be respected.

The Board must control its regulatory process. The Board hears a large number of cases throughout the year and must plan its resources accordingly to ensure cases are completed and decisions are rendered. In cases where utilities have not filed their applications in time to have rates in place prior to the effective date, the Board's practice has typically been to not allow the utility to retrospectively recover the amounts from the period where the interim order was in effect.[124] All applicants are aware of the Board's metrics. The process for an oral hearing is expected to take 235 days from the filing of the application to the issuance of the final decision, and 280 days until the issuance of the rate order.

OPG understood the timelines associated with filing a cost of service application and its witnesses confirmed that it was unlikely that the Board could have completed the process by January 1, 2014 given a September 27, 2013 filing date.[125] Even if a complete application had been filed in September, there was no scenario under which the proceeding could have been completed by January 1, 2014. OPG's proposal would result in the entire two-year increase for the previously regulated assets being recovered over a significantly shorter time period, resulting in a higher monthly bill impact increases exceeding the $5.36 and $5.94 identified in the two published Notices of Application. OPG estimated the impact of establishing effective dates of January 1, 2014 for the previously regulated assets and July 1, 2014 for the newly regulated assets was $649M or 43% over current payment amounts,[126] assuming an implementation date of September 1, 2014. A September 1, 2014 implementation date was used to calculate the magnitude of the increase during the oral phase of the proceeding; a November implementation date, assuming OPG's proposed payment amounts, would result in a percentage increase higher than 43%.

Ratepayers who made consumption decisions from January 1, 2014 to November 1, 2014, who thought they had already paid their electricity bills may be surprised to learn they will be responsible for additional costs, recovered through higher rates to be included on future bills until December 31, 2015. In addition, a January 1, 2014

[124] EB-2012-0165 (Sioux Lookout); EB-2013-0139 (Hydro Hawkesbury); EB-2012-0113 Centre Wellington; EB-2013-0130 Fort Frances
[125] Tr Vol 2 page 171
[126] Undertaking J3.10

effective date would result in some level of inter-generational inequity, to the extent customer profiles changed over that time.

The Board finds that the reasons this proceeding could not be completed by January 1, 2014 were almost entirely within OPG's control. OPG's witnesses indicated the earliest date the application would have been ready to file was August 2013. OPG's management made the decision to delay the filing further to include the newly prescribed hydroelectric assets. OPG indicated that it would not be practical or workable to file one application regarding the previously regulated assets first and then file a second application or update for the newly regulated assets at a later date. OPG's management had choices and made decisions regarding the timing, inclusion and exclusion of evidence. For example, OPG indicated its plans to file a separate application for disposition of deferral and variance account balances as of December 31, 2014;[127] an application the Board has yet to receive. In addition, OPG understands that options are available to separate issues in distinct applications for significant issues to expedite the hearing process. In fact, OPG asked the Board to consider a stand-alone Niagara Tunnel Project hearing. The Board responded to OPG's request in a letter dated April 13, 2012 and agreed that given the scale and complexity of the Niagara Tunnel Project, it was appropriate to consider a separate 2013-2014 payment amounts application. In the end, OPG decided not file a separate Niagara Tunnel application nor a payment amount application for 2013 rates.

When OPG filed its application on September 27, 2013, it was incomplete. A complete application was filed on December 5, 2013, less than one month before its proposed effective date.

The Board decided to issue a notice for the proceeding on October 25, 2013 based on the incomplete application in order to avoid further delay; however, the Board stated: "[t]he timing of any further procedural steps will be dependent on OPG's response to the items noted in this correspondence."

On December 6, 2013, one day after filing the complete application on December 5, 2013, OPG filed a major update to its application which required the issuance of a new notice, and essentially brought the proceeding back to step 1. New information continued to be filed, including updated evidence on the Darlington refurbishment

[127] Exh H1-1-1 page 1

project filed on July 2, 2014 which necessitated a delay of the oral hearing by several weeks.

The Board's decision is based on a balancing of the interests of the applicant and of the ratepayer. The timing of the application is solely in OPG's control, and the Board's metrics and policies regarding effective dates are well known. For the reasons provided above, the Board approves an effective date of November 1, 2014 for the previously regulated assets.

Effective Date for Newly Regulated Hydroelectric Payment Amounts

The Board has determined that the effective date for the final payment amounts shall be November 1, 2014 for the newly regulated hydroelectric facilities. As mandated by O. Reg. 53/05, the Board's regulation of the payment amounts for the newly regulated hydroelectric facilities commenced on July 1, 2014. From July 1, 2014 through October 31, 2014 the Board has determined that the payment amounts for the newly regulated hydroelectric facilities will remain HOEP, which is the amount that OPG actually recovered over that time period pursuant to the Board's interim rate order.

The Board accepts the arguments of the parties that argued that the Board is not legally required to set July 1, 2014 as the effective date for the final payment amounts applicable to the newly hydroelectric regulated facilities. O. Reg. 53/05 requires the Board to commence its payment regulation of the newly regulated hydroelectric facilities as of July 1, 2014; it does not require the Board to set the payment amounts at any particular level. In fact the regulation appears to contemplate that the effective date of the final payment order may well come after July 1, 2014: "[t]he 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 [i.e. the newly regulated facilities] **during the period from July 1, 2014 to the day before the effective date of the order**."

The Board has determined that it is not legally required to set the effective date of the final order for the newly regulated hydroelectric facilities to July 1, 2014. The Board has decided that it would be inappropriate to do so. The Board orders that the effective date for the final payment order for the newly regulated hydroelectric facilities will be November 1, 2014.

OPG takes the position that given the September 2013 notice of the proposed amendment to O. Reg. 53/05 to regulate the newly regulated hydroelectric facilities, OPG could not have filed the application for the associated payment amounts any earlier than it did. OPG argues that it was dependent upon the Ministry's release of the proposal to amend the regulation in order to proceed with the application.

The draft regulation was published for comment in July 2013. The notice of the proposed amended regulation was made public in September 2013 and the regulation was filed in November 2013. The Board considers that an application could have been filed shortly after the draft regulation was published for comment (i.e. after July 2013). Indeed OPG did not wait for the regulation to be finalized before filing its original application.

It appears to the Board that OPG had various options available to it as to when it could have filed its application. In fact, the inclusion in the application of the newly regulated hydroelectric facilities was an issue of little controversy in this proceeding. One of the options it could have considered was to file the newly regulated hydroelectric portion of the application as an update to the payment amounts case which could have been filed earlier. Instead, OPG waited for the regulation to be issued as a draft before filing the entire payments amounts application. Other options were available as well, all of which could have resulted in finalized payment amounts at an earlier point in time. The Board has based its decision on the regulatory principle that rates should be set on a forward test year basis. The Board reiterates its reasons outlined in respect of the effective date for the nuclear and previously regulated hydroelectric payment amounts. The Board's position is that rates should be based on a forecast test year which establishes rates on a go forward basis, not retrospectively. This allows ratepayers to make informed consumption choices and provides utilities with certainty regarding revenue on a go-forward basis. OPG's evidence regarding when it could have filed its application is not so compelling as to move the Board off its practice of making rates effective in the month following the Board's final decision.

In the previous cost of service proceeding, the decision was issued on March 10, 2011 and the effective date was March 1, 2011. The IESO was able to implement the effective date through its billing processes without the necessity for shortfall payment amount riders to cover the period between March 1, 2011 and the date of the final payment amounts order. The Board expects that the same process can be accommodated in the current proceeding with a November 1, 2014 implementation for both the previously regulated and newly regulated assets.

The Board directs OPG to file with the Board, and copy to all intervenors, a draft payment amounts order which will include the final revenue requirement and payment amounts for the regulated hydroelectric and nuclear facilities, and reflect the findings made by the Board in this Decision. OPG should also include supporting schedules and a clear explanation of all calculations and assumptions used in deriving the payment amounts and the payment riders. The draft payment amounts order shall be filed by December 1, 2014.

OPG is directed to provide a full description of each deferral and variance account as part of the draft payment amounts order.

Board staff and intervenors shall respond to OPG's draft payment order by December 8, 2014. OPG shall respond to any comments by Board staff and intervenors by December 12, 2014.

12 COST AWARDS

A number of intervenors were deemed eligible for cost awards in this proceeding: Association of Major Power Consumers in Ontario, Canadian Manufacturers & Exporters, Consumers Council of Canada, Energy Probe Research Foundation, Environmental Defence, Green Energy Coalition, Haudenosaunee Development Institute, Lake Ontario Waterkeeper, London Property Management Association, Retail Council of Canada, School Energy Coalition, Sustainability Journal and Vulnerable Energy Consumers Coalition.

At the oral hearing on June 12, 2014, the Board set out the process for intervenors to file their cost claims for the period ending June 11, 2014 for interim disposition. The cost award decision was issued on July 24, 2014.

A cost award decision for the period starting June 12, 2014 will be issued after the steps set out below are completed.

1. Intervenors eligible for cost awards shall file with the Board and forward to OPG their respective cost claims by December 15, 2014.
2. OPG shall file with the Board and forward to the relevant intervenors any objections to the costs claimed, including any objections to cost claims filed prior to the issuance of this Decision, by December 23, 2014.
3. Intervenors whose costs have been objected to, may file with the Board and forward to OPG any response to the objection by January 7, 2015.

OPG shall pay the Board’s costs of and incidental to this proceeding upon receipt of the Board’s invoice.

DATED at Toronto, November 20, 2014

ONTARIO ENERGY BOARD

Original signed by

Marika Hare
Presiding Member

Original signed by

Christine Long
Member

Original signed by

Allison Duff
Member

APPENDICES

TO

DECISION WITH REASONS

EB-2013-0321

ONTARIO POWER GENERATION INC.

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, or to the OPA on behalf of a generator prescribed by the regulations, with respect to output that is generated by a unit at a generation facility prescribed by the regulations. 2004, c. 23, Sched. B, s. 15.

Note: On January 1, 2015, the day named by proclamation of the Lieutenant Governor, subsection (1) is repealed and the following substituted: (See: 2014, c. 7, Sched. 23, ss. 7, 16)

Payments to prescribed generator

(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,

(a) in accordance with the regulations to the extent the payment relates to a period that is on or after the day this section comes into force and before the later of,

(i) the day prescribed for the purposes of this subsection, and

(ii) the effective date of the Board's first order in respect of the generator; and

(b) in accordance with the order of the Board then in effect to the extent the payment relates to a period that is on or after the later of,

(i) the day prescribed for the purposes of this subsection, and

(ii) the effective date of the Board's first order under this section in respect of the generator. 2004, c. 23, Sched. B, s. 15.

Note: On January 1, 2015, the day named by proclamation of the Lieutenant Governor, subsection (2) is repealed and the following substituted: (See: 2014, c. 7, Sched. 23, ss. 7, 16)

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.

OPA may act as settlement agent

(3) The OPA may act as a settlement agent to settle amounts payable to a generator under this section. 2004, c. 23, Sched. B, s. 15.

Note: On January 1, 2015, the day named by proclamation of the Lieutenant Governor, subsection (3) is repealed. (See: 2014, c. 7, Sched. 23, ss. 7, 16)

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.

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 July 1, 2014 to the e-Laws currency date.

Last amendment: O. Reg. 312/13.

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;

"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;

"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. O. Reg. 23/07, 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.

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 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. O. Reg. 23/07, s. 4; O. Reg. 27/08, s. 2; O. Reg. 312/13, s. 4.

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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Filed: 2013-09-27
EB-2013-0321
Exhibit A1-4-1
Attachment 2

Memorandum of Agreement

BETWEEN

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

Purpose

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

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

A. Mandate

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

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

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

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

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

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

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

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

B Governance Framework

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

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

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

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

C. Generation Performance and Investment Plans

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

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

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

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

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

D. Financial Framework

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

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

E. Communication and Reporting

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

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

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

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

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

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

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

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

F. Review of this Agreement

This agreement will be reviewed and updated as required.

Dated: the 17th day of August, 2005

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

APPROVALS

Updated to reflect the Second Impact Statement (Ex. N2-1-1)

In this Application, OPG is seeking the following specific approvals:

- The approval of a revenue requirement of $1,757.8M for the previously regulated hydroelectric facilities and a revenue requirement of $6,395.4M for the nuclear facilities for the period of January 1, 2014 through December 31, 2015 as set out in Ex. N2-1-1.

- The approval of an 18 month revenue requirement of $853.2M for the newly regulated hydroelectric facilities for the period of July 1, 2014 through December 31, 2015, calculated as one half of a 2014 revenue requirement of $554.6M plus a 2015 revenue requirement of $575.9, as set out in Ex. N2-1-1.

- The approval of a rate base of $5,128.0M and $5,084.6M for the previously regulated hydroelectric facilities for the years 2014 and 2015, respectively; a rate base of $2,511.5M and $2,528.2M for the newly regulated hydroelectric facilities for the years 2014 and 2015, respectively; and $3,706.7M and $3,659.0M for the nuclear facilities for the years 2014 and 2015, respectively, as summarized in Ex. B1-1-1.

- Approval of a production forecast of 41.1 TWh for 2014 and 2015 for the previously regulated hydroelectric facilities, a production forecast of 17.9 TWh for July 1, 2014 to December 31, 2015 for the newly regulated hydroelectric facilities; and 94.6 TWh for 2014 and 2015 for the nuclear facilities. The production forecasts are presented in Ex. E1-1-1 and Ex. E2-1-1 and updated in Ex. N1-1-1 and N2-1-1.

- Approval of a deemed capital structure of 53 per cent debt and 47 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 Board's Cost of Capital Report, and currently set at 9.36 per cent for 2014 and forecast at 9.53 per cent for 2014 and 2015, as presented in Ex. N2-1-1.

- Approval of a payment amount for the previously regulated hydroelectric facilities, of $42.75/MWh effective January 1, 2014 for the average hourly net energy production (MWh) from the previously regulated hydroelectric facilities in any given month (the "hourly volume") for each hour of that month. Production over the hourly volume will receive the market price from the Independent Electricity System Operator ("IESO")-administered energy market adjusted as described at Ex. E1-2-1. Where production from the previously regulated hydroelectric facilities is less than the hourly volume, OPG's revenues will be adjusted by the difference between the hourly volume and the actual net energy production at the market price from the IESO-administered market adjusted as described at Ex. E1-2-1. The calculation of the payment amount for the previously regulated hydroelectric facilities is set out in Ex. I1-2-1 as updated in Ex. N2-1-1.

- Approval of a payment amount for the newly regulated hydroelectric facilities, of $47.57/MWh effective July 1, 2014 for the average hourly net energy production (MWh) from the newly regulated facilities in any given month (the "hourly volume") for each hour of that month. Production over the hourly volume will receive the market price from the Independent Electricity System Operator ("IESO")-administered energy market adjusted as described at Ex. E1-2-1. Where production from the newly regulated hydroelectric facilities is less than the hourly volume, OPG's revenues will be adjusted by the difference between the hourly volume and the actual net energy production at the market price from the IESO-administered market adjusted as described at Ex. E1-2-1. The calculation of the payment amount for the newly regulated hydroelectric facilities is set out in Ex. I1-2-1 as updated in Ex. N2-1-1.

- Approval of a payment amount for the nuclear facilities, of $67.60/MWh effective January 1, 2014.

- Approval for recovery of the audited December 31, 2013 balances of the Hydroelectric Incentive Mechanism, Surplus Baseload Generation and Capacity Refurbishment-Hydroelectric variance accounts for the previously regulated hydroelectric facilities, of $127.0M, as described in Ex. H1-1-2, as updated in Ex. N2-1-1, and disposition, beginning January 1, 2015, at a rate of $3.36/MWh applied to the output from the previously regulated hydroelectric facilities.

- Approval for recovery of the audited December 31, 2013 balance of the Nuclear Development Variance Account and a portion of the balance of the Capacity Refurbishment Variance Account - Nuclear for the nuclear facilities, of $62.2M as described in Ex. H1-2-1, as updated in Ex. N2-1-1, and disposition, beginning January 1, 2015, at a rate of $1.35/MWh applied to the output from the nuclear facilities.

- Approval to establish, re-establish or continue variance and deferral accounts as follows:
    - A variance account to record the deviation from forecast revenues associated with differences in regulated hydroelectric electricity production due to differences between forecast and actual water conditions.
    - A variance account to record the deviation from forecast net revenues for ancillary services from the regulated hydroelectric facilities and the nuclear facilities.
    - A variance account to record the financial impact of foregone production at its regulated hydroelectric facilities due to surplus baseload generation.
    - A variance account to record interest and amortization of the accumulations up to year end 2013 of 50 per cent of the Hydroelectric Incentive Mechanism net revenues above amounts underpinning the EB-2010-0008 revenue requirement as a credit to ratepayers, proposed to be terminated December 31, 2015.
    - A variance account to record the deviation from forecast capital and non-capital costs and firm financial commitments associated with work to increase

the output of, refurbish or add operating capacity to a regulated facility.

- A variance account to record the deviation from forecast costs incurred and firm financial commitments made in the course of planning and preparation for the development of proposed new nuclear generation facilities.
- A deferral account to record the revenue requirement impact of any change in the nuclear decommissioning liability resulting from an approved reference plan as defined in the Ontario Nuclear Funds Agreement.
- A variance account to capture the tax impact of changes in tax rates, rules and assessments.
- A variance account to record the variance between the tax loss mitigation amount which underpins the EB-2007-0905 Payment Amounts Order and the tax loss amount resulting from the re-analysis of the prior period tax returns based on the OEB's directions in EB-2007-0905 Decision with Reasons as to the re-calculation of those tax losses, to be terminated December 31, 2014.
- A variance account to capture differences between forecast and actual costs and revenues related to the lease of the Bruce nuclear facilities and associated tax effects.
- A variance account to capture depreciation cost differences due to a revised service life, for accounting purposes, of the Pickering nuclear facility.
- A variance account to record the difference between forecast and actual pension and other post-employment benefit costs and associated tax effects related to the regulated hydroelectric and nuclear facilities.
- A deferral account to record the transition and implementation impacts associated with the adoption of the Generally Accepted Accounting Principle of the United States ("USGAAP"), to be terminated December 31, 2014.
- Variance accounts to record the over/under recovery amounts for the hydroelectric variance and deferral accounts and nuclear variance and deferral accounts, respectively.

Evidence supporting the continuation of existing variance and deferral accounts and the creation of new ones is provided in Ex. H1-3-1.

- In respect of the Darlington Refurbishment Project ("DRP") OPG seeks the following as described in Ex. D2-2-1:
    - A finding that OPG's commercial and contracting strategies for the DRP are reasonable;
    - A finding that the proposed capital expenditures of $837.4M in 2014 and $631.8M in 2015 are reasonable;
    - Approval of OM&A expenditures of $6.6M in 2014 and $18.2M in 2015 (Ex. F2-7-1, Ex. N2-1-1);
    - Approval of in-service additions to rate base of $5.0M in 2012, $104.2M in 2013, $18.7M in 2014, and $209.4M in 2015 for new facilities and related 2014 and 2015 depreciation expense; and
    - Approval to recover the capital cost portion of the actual audited nuclear balance in the Capacity Refurbishment Variance Account as at December 31, 2013 of $5.7M.

- An order from the OEB declaring OPG's current payment amounts for previously regulated hydroelectric and nuclear facilities interim as of January 1, 2014, if the order or orders approving the payment amounts are not implemented by January 1, 2014.

- An order from the OEB declaring OPG's current payment amounts for the newly regulated hydroelectric facilities interim as of July 1, 2014, if the order or orders approving the payment amounts are not implemented by July 1, 2014.

PROCEDURAL DETAILS INCLUDING LISTS OF PARTIES AND WITNESSES

THE PROCEEDING

OPG filed its application for new payment amounts on September 27, 2013. On October 25, 2014, the Board issued a Notice of Application and Oral Hearing which was published in accordance with the Board's direction.

The key milestones in the proceeding are listed below:

- The application, as filed, was incomplete and OPG filed additional pre-filed evidence on December 5, 2013.
- OPG filed an impact statement on December 6, 2013 (Exhibit N1) that updated the application to reflect material changes in costs and production forecasts for the 2014-2015 period that are included in OPG's 2014-2016 business plan.
- An interim order declaring payment amounts for the previously regulated hydroelectric facilities and nuclear facilities interim effective January 1, 2014, and for the newly regulated hydroelectric facilities interim effective July 1, 2014, was issued on December 17, 2013.
- The Board issued Procedural Order No.1 on December 20, 2013. Given the material change in customer impact reported in the Exhibit N1 update filed on December 6, 2013, the Board determined that further notice was required. 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. The procedural order also set out a schedule for interrogatories.
- The final unprioritized issues list was issued along with Procedural Order No. 3 on February 19, 2014.
- Interrogatories were filed by Board staff on February 21, 2014 and by intervenors on February 28, 2014. The majority of responses were filed on March 19, 2014.
- Procedural Order No. 5, issued on April 3, 2014, set out the schedule for the settlement conference and oral hearing.
- A technical conference was held April 22 and 23, 2014. A second technical conference, related to the Darlington Refurbishment Project, was held July 8 and 9, 2014.
- A motion hearing was held on May 9, 2014.

- A second impact statement was filed on May 16, 2014 (Exhibit N2) to update the application to reflect material changes in costs and production forecasts that had arisen since the first impact statement was filed.
- A settlement conference was held May 21, 2014 to May 26, 2014, however no settlement was achieved.
- The final prioritized issues list was issued along with Procedural Order No. 10 on June 4, 2014.
- The oral hearing took place on 16 days during the period June 12, 2014 to July 18, 2014.
- OPG filed its Argument-in-Chief on July 28, 2014.
- Board staff filed its submission on August 19, 2014 and intervenors filed their submissions on August 26, 2014 except the Society of Energy Professional who filed on August 29, 2014.
- OPG's reply argument was filed on September 10, 2014.

Fourteen 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, and submissions.

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 Carlton Mathias Andrew Barrett Colin Anderson

Board Counsel and Staff	Michael Millar Violet Binette Ben Baksh Richard Battista Russell Chute Keith Ritchie Duncan Skinner
Association of Major Power Consumers in Ontario	David Crocker Hamza Mortage Shelley Grice
Canadian Manufacturers & Exporters	Peter Thompson Vince DeRose Emma Blanchard
Consumers Council of Canada	Julie Girvan
Energy Probe Research Foundation	David MacIntosh Lawrence Schwartz
Environmental Defence	Kent Elson
Green Energy Coalition	David Poch
Haudenosaunee Development Institute	Aaron Detlor
Independent Electricity System Operator	Glenn Zacher Jessica Savage Tam Wagner
Lake Ontario Waterkeeper	Pippa Feinstein
London Property Management Association	Randy Aiken

Ontario Power Authority	Fred Cass Miriam Heinz
Power Workers' Union	Richard Stephenson Alfredo Bertolotti
Retail Council of Canada	Travis Allan
School Energy Coalition	Jay Shepherd Mark Rubenstein Mark Garner
Society of Energy Professionals	Mike Belmore Russ Houldin
Sustainability-Journal	Ron Tolmie
Vulnerable Energy Consumers Coalition	Michael Janigan James Wightman

In addition to the above, Enwin Utilities Ltd., HQ Energy Marketing Inc. and Shell Energy North America (Canada) Inc. were registered intervenors in this proceeding. Marc Raymond and the Ministry of Energy were registered observers in this proceeding.

WITNESSES

The following OPG employees appeared as witnesses.

Andrew Barrett	Vice President, Regulatory Affairs
John Mauti	Vice President, Business Planning & Reporting
Nicolle Butcher	Project Executive, Business Transformation (Acting)
Mario Mazza	Vice President, Strategy & Business Support, Hydro

	Thermal Operations
Robby Sohi	Director, Plant Engineering Services, Hydro Thermal Operations
Bill Wilbur	Director, Generation & Revenue Planning, Commercial Operations & Environment Business Unit
Chris Young	Vice President, Hydroelectric and Thermal Project Execution
Laurie Swami	Vice President, Nuclear Services
Carla Carmichael	Vice President, Nuclear Finance
John Blazanin	Director, Controllership, Nuclear Finance
Jamie Lawrie	Project Director
Jason Fitzsimmons	Vice President, Health and Safety, Labour and Employee Relations
Ali Earle	Director, Human Resources
Lubna Ladak	Director, Controllership
Alex Kogan	Director, Business Planning and Regulatory Finance
Dietmar Reiner	Senior Vice President, Nuclear Projects
Gary Rose	Director of Refurbishment, Planning and Control

OPG also called the following expert witness: Roger Ilsley of R I Geotechnical Inc., Richard Chaykowski of Queen’s University, Kathleen McShane of Foster Associates Inc., Eric Gould of Modus Strategic Solutions and John Reed of Concentric Energy Advisors.

Ontario Power Generation Inc.
2014-2015 Payment Amounts for
Prescribed Generating Facilities
EB-2013-0321

FINAL ISSUES LIST (REPRIORITIZED)

1. GENERAL

1.1 Primary - Has OPG responded appropriately to all relevant Board directions from previous proceedings?
1.2 Primary - Are OPG's economic and business planning assumptions for 2014-2015 appropriate?
1.3 Secondary - Has OPG appropriately applied USGAAP accounting requirements, including identification of all accounting treatment differences from its last payment order proceeding?
1.4 Oral Hearing: Is the overall increase in 2014 and 2015 revenue requirement reasonable given the overall bill impact on customers?

2. RATE BASE

2.1 Primary - Are the amounts proposed for rate base appropriate?

3. CAPITAL STRUCTURE AND COST OF CAPITAL

3.1 Primary - What is the appropriate capital structure and rate of return on equity for the currently regulated facilities and newly regulated facilities?
3.2 Secondary - Are OPG's proposed costs for its long-term and short-term debt components of its capital structure appropriate?

4. CAPITAL PROJECTS

Regulated Hydroelectric

4.1 Secondary - Do the costs associated with the regulated hydroelectric projects that are subject to section 6(2)4 of O. Reg. 53/05 and proposed for recovery (excluding the Niagara Tunnel Project), meet the requirements of that section?
4.2 Secondary - Are the proposed regulated hydroelectric capital expenditures and/or financial commitments reasonable?

4.3 Secondary - Are the proposed test period in-service additions for regulated hydroelectric projects (excluding the Niagara Tunnel Project) appropriate?

4.4 Primary - Do the costs associated with the Niagara Tunnel Project that are subject to section 6(2)4 of O. Reg. 53/05 and proposed for recovery, meet the requirements of that section?

4.5 Primary - Are the proposed test period in-service additions for the Niagara Tunnel Project reasonable?

Nuclear

4.6 Primary (reprioritized) - 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?

4.7 Oral Hearing: Are the proposed nuclear capital expenditures and/or financial commitments reasonable?

4.8 Primary (reprioritized) - Are the proposed test period in-service additions for nuclear projects (excluding those for the Darlington Refurbishment Project) appropriate?

4.9 Primary - Are the proposed test period in-service additions for the Darlington Refurbishment Project) appropriate?

4.10 Primary - Are the proposed test period capital expenditures associated with the Darlington Refurbishment Project reasonable?

4.11 Oral Hearing: Are the commercial and contracting strategies used in the Darlington Refurbishment Project reasonable?

4.12 Primary - Does OPG’s nuclear refurbishment process align appropriately with the principles stated in the Government of Ontario’s Long Term Energy Plan issued on December 2, 2013?

5. PRODUCTION FORECASTS

Regulated Hydroelectric

5.1 Secondary - Is the proposed regulated hydroelectric production forecast appropriate?

5.1(a) Primary - Could the storage of energy improve the efficiency of hydroelectric generating stations?

5.2 Primary (reprioritized) - Is the estimate of surplus baseload generation appropriate?

5.3 Secondary - Has the incentive mechanism encouraged appropriate use of the regulated hydroelectric facilities to supply energy in response to market prices?

5.4 Primary - Is the proposed new incentive mechanism appropriate?

Nuclear

5.5 Primary - Is the proposed nuclear production forecast appropriate?

6. OPERATING COSTS

Regulated Hydroelectric

6.1 Oral Hearing: Is the test period Operations, Maintenance and Administration budget for the regulated hydroelectric facilities appropriate?

6.2 Oral Hearing: Is the benchmarking methodology reasonable? Are the benchmarking results and targets flowing from those results for the regulated hydroelectric facilities reasonable?

Nuclear

6.3 Oral Hearing: Is the test period Operations, Maintenance and Administration budget for the nuclear facilities appropriate?

6.4 Oral Hearing: Is the benchmarking methodology reasonable? Are the benchmarking results and targets flowing from those results for the nuclear facilities reasonable?

6.5 Secondary - Is the forecast of nuclear fuel costs appropriate? Has OPG responded appropriately to the suggestions and recommendations in the Uranium Procurement Program Assessment report?

6.6 Primary (reprioritized) - Are the test period expenditures related to continued operations for Pickering Units 5 to 8 appropriate?

6.7 Primary - Is the test period Operations, Maintenance and Administration budget for the Darlington Refurbishment Project appropriate?

Corporate Costs

6.8 Oral Hearing: Are the 2014 and 2015 human resource related costs (wages, salaries, benefits, incentive payments, FTEs and pension costs) appropriate?

6.9 Oral Hearing: Are the corporate costs allocated to the regulated hydroelectric and nuclear businesses appropriate?

6.10 Oral Hearing: Are the centrally held costs allocated to the regulated hydroelectric business and nuclear business appropriate?

Depreciation

6.11 Secondary - Is the proposed test period depreciation expense appropriate?

6.12 Secondary - Are the depreciation studies and associated proposed changes to depreciation expense appropriate?

Income and Property Taxes

6.13 Primary (reprioritized) - Are the amounts proposed to be included in the test period revenue requirement for income and property taxes appropriate?

Other Costs

6.14 Secondary - Are the asset service fee amounts charged to the regulated hydroelectric and nuclear businesses appropriate?

6.15 Secondary - Are the amounts proposed to be included in the test period revenue requirement for other operating cost items appropriate?

7. OTHER REVENUES

Regulated Hydroelectric

7.1 Secondary - Are the proposed test period revenues from ancillary services, segregated mode of operation and water transactions appropriate?

Nuclear

7.2 Secondary - Are the forecasts of nuclear business non-energy revenues appropriate?

Bruce Nuclear Generating Station

7.3 Secondary - 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 (reprioritized) - Is the revenue requirement impact of the nuclear liabilities appropriately determined?

9. DEFERRAL AND VARIANCE ACCOUNTS

9.1 Secondary - Is the nature or type of costs recorded in the deferral and variance accounts appropriate?

9.2 Secondary - Are the balances for recovery in each of the deferral and variance accounts appropriate?

9.3 Secondary - Are the proposed disposition amounts appropriate?

9.4 Secondary - Is the disposition methodology appropriate?

9.5 Secondary - Is the proposed continuation of deferral and variance accounts appropriate?

9.6 Oral Hearing: Is OPG's proposal to not clear deferral and variance account balances in this proceeding (other than the four accounts directed for clearance in EB-2012-0002) appropriate?

9.7 Primary (reprioritized) - Is OPG's proposal to make existing hydroelectric variance accounts applicable to the newly regulated hydroelectric generation facilities appropriate?

9.8 Secondary - Is the proposal to discontinue the Hydroelectric Incentive Mechanism Variance Account appropriate?

9.9 Primary (reprioritized) - What other deferral accounts, if any, should be established for OPG?

10. REPORTING AND RECORD KEEPING REQUIREMENTS

10.1 Secondary - What additional reporting and record keeping requirements should be established for OPG?

11. METHODOLOGIES FOR SETTING PAYMENT AMOUNTS

11.1 Oral Hearing: Has OPG responded appropriately to Board direction on establishing incentive regulation?

11.2 Secondary - Is the design of the regulated hydroelectric and nuclear payment amounts appropriate?

11.3 Oral Hearing: To what extent, if any, should OPG implement mitigation of any rate increases determined by the Board? If mitigation should be implemented, what is the appropriate mechanism that should be used?

12. IMPLEMENTATION

12.1 Oral Hearing: Are the effective dates for new payment amounts and riders appropriate?

Ontario Energy Board

Commission de l'énergie de l'Ontario

EB-2016-0152

Ontario Power Generation Inc.

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

INTERIM PAYMENT AMOUNTS ORDER
December 8, 2016

Ontario Power Generation Inc. (OPG) filed an application with the Ontario Energy Board (OEB) on May 27, 2016 under section 78.1 of the *Ontario Energy Board Act*, *1998*, S.O. 1998, c. 15, (Schedule B), seeking approval for changes in payment amounts for the output of its nuclear generating facilities and most of its hydroelectric generating facilities. The request seeks approval for nuclear payment amounts to be effective January 1, 2017 and for each following year through to December 31, 2021. The request seeks approval for hydroelectric payment amounts to be effective January 1, 2017 to December 31, 2017 and approval of the hydroelectric payment amount setting formula for the period January 1, 2017 to December 31, 2021.

OPG seeks an order declaring the current payment amounts interim effective January 1, 2017 for the regulated hydroelectric and nuclear facilities, if the order or orders approving the payment amounts in the current proceeding are not implemented by January 1, 2017.

The OEB will not be in a position to render a final decision in time to implement new final payment amounts on January 1, 2017. The OEB is prepared to make OPG's current payment amounts for the regulated hydroelectric and nuclear facilities interim pending the OEB's final decision. This determination is made without prejudice to the OEB's ultimate decision on OPG's application, and should not be construed as predictive, in any way whatsoever, of the OEB's final determination with regards to the effective date for OPG's payment amounts arising from this application.

THE ONTARIO ENERGY BOARD THEREFORE ORDERS THAT:

1. The currently approved payment amounts for the regulated hydroelectric and nuclear facilities are declared interim as of January 1, 2017 and until such time as a final payment amounts order is issued by the OEB.

DATED at Toronto, **December 8, 2016**

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

Ontario Energy Board Act, 1998, S.O. 1998, c. 15, Sched. B

s. 78.1

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.

2015 SCC 44, 2015 CSC 44
Supreme Court of Canada

Ontario (Energy Board) v. Ontario Power Generation Inc.

2015 CarswellOnt 14395, 2015 CarswellOnt 14396, 2015 SCC 44, 2015 CSC 44, [2015] 3 S.C.R. 147, 135 O.R. (3d) 160 (note), 257 A.C.W.S. (3d) 252, 338 O.A.C. 1, 388 D.L.R. (4th) 540, 475 N.R. 1, 95 Admin. L.R. (5th) 1, J.E. 2015-1505

Ontario Energy Board, Appellant and Ontario Power Generation Inc., Power Workers' Union, Canadian Union of Public Employees, Local 1000 and Society of Energy Professionals, Respondents and Ontario Education Services Corporation, Intervener

McLachlin C.J.C., Abella, Rothstein, Cromwell, Moldaver, Karakatsanis, Gascon JJ.

Heard: December 3, 2014
Judgment: September 25, 2015
Docket: 35506

Proceedings: reversing *Hydro One Networks Inc., Re* (2013), (sub nom. *Power Workers' Union, Canadian Union of Public Employees, Local 1000 v. Ontario Energy Board)* 116 O.R. (3d) 793, 2013 CarswellOnt 9792, (sub nom. *Power Workers' Union v. Ontario Energy Board)* 307 O.A.C. 109, 365 D.L.R. (4th) 247, 2013 ONCA 359, M. Rosenberg J.A., R.A. Blair J.A., S.T. Goudge J.A. (Ont. C.A.); reversing *Hydro One Networks Inc., Re* (2012), 2012 CarswellOnt 2709, 2012 ONSC 1080, Aitken J., Hoy J., Swinton J. (Ont. Div. Ct.); affirming *Hydro One Networks Inc., Re* (2010), 2010 CarswellOnt 10806, Ken Quesnelle Member, Paul Sommerville Presiding Member, Paula Conboy Member (Ont. Energy Bd.)

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Paul J.J. Cavalluzzo, Amanda Darrach, for Respondent, Society of Energy Professionals
Mark Rubenstein, for Intervener

Subject: Public; Labour
Related Abridgment Classifications
Administrative law
IV Standard of review
  IV.4 Miscellaneous
Labour and employment law
I Labour law
  I.6 Collective agreement
    I.6.z Miscellaneous
Public law
IV Public utilities
  IV.5 Regulatory boards
    IV.5.b Regulation of rates
Public law
IV Public utilities
  IV.5 Regulatory boards

IV.5.c Practice and procedure
IV.5.c.iv Miscellaneous

Headnote

Public law --- Public utilities — Regulatory boards — Practice and procedure — Miscellaneous

Utility sought to recover incurred or committed labour compensation costs in utility rates — Ontario Energy Board disallowed utility's claim for $145 million in costs on grounds that utility's labour costs were too high — Utility appealed — Divisional Court dismissed utility's appeal — Court of Appeal allowed utility's appeal — Board appealed to Supreme Court of Canada — Appeal allowed — It was not improper for Board to argue in favour of reasonableness of its decision on appeal — Board was only respondent in initial review of its decision, it had no alternative but to step in if decision was to be defended on merits — Board was exercising regulatory role by setting just and reasonable payment amounts to utility — Arguments raised by Board on appeal did not amount to impermissible bootstrapping.

Public law --- Public utilities — Regulatory boards — Regulation of rates

Utility sought to recover $145 million in incurred or committed labour compensation costs in utility rates — Ontario Energy Board disallowed utility's claim on grounds that utility's labour costs were too high — Divisional Court dismissed utility's appeal — Court of Appeal allowed utility's appeal — Board appealed to Supreme Court of Canada — Appeal allowed — Board did not act unreasonably in not applying prudent investment test — Ontario Energy Board Act, 1998 places burden on applicant utility to establish that payments amounts approved by Board are just and reasonable — Where statute requires only that regulator set "just and reasonable" payments, regulator may use variety of analytical tools to assess justness and reasonableness of utility's proposed payment amounts, particularly where regulator has express discretion over methodology for setting payment amounts — Labour costs in issue were partly committed costs and partly costs subject to management discretion — It was unreasonable to treat such costs as entirely forecast, but Board was not bound to apply particular prudence test in evaluating these costs — It is not necessarily unreasonable, in light of regulatory structure in Act, for Board to evaluate committed costs using method other than no-hindsight prudence review — Board's decision did not purport to force utility to break its contractual commitments to unionized employees.

Labour and employment law --- Labour law — Collective agreement — Miscellaneous

Utility sought to recover $145 million in incurred or committed labour compensation costs in utility rates — Ontario Energy Board disallowed utility's claim on grounds that utility's labour costs were too high — Divisional Court dismissed utility's appeal — Court of Appeal allowed utility's appeal — Board appealed to Supreme Court of Canada — Appeal allowed — Where statute requires only that regulator set "just and reasonable" payments, regulator may use variety of analytical tools to assess justness and reasonableness of utility's proposed payment amounts, particularly where regulator has express discretion over methodology for setting payment amounts — Labour costs in issue were partly committed costs and partly costs subject to management discretion — It was unreasonable to treat such costs as entirely forecast, but Board was not bound to apply particular prudence test in evaluating these costs — It is not necessarily unreasonable, in light of regulatory structure in Ontario Energy Board Act, 1998, for Board to evaluate committed costs using method other than no-hindsight prudence review — Board's decision did not purport to force utility to break its contractual commitments to unionized employees.

Administrative law --- Standard of review — Miscellaneous

Utility sought to recover incurred or committed compensation costs in utility rates — Ontario Energy Board disallowed $145 million in labour compensation costs on grounds that utility's labour costs were too high — Divisional Court dismissed utility's appeal — Court of Appeal allowed utility's appeal — Board appealed to Supreme Court of Canada — Appeal allowed on other grounds — Reasonableness is appropriate standard of review for Board's actions in applying its expertise to set rates and approve payment amounts under Ontario Energy Board Act, 1998 — To extent resolution of appeal turned on interpretation of Act, standard of reasonableness presumptively applied.

Droit public --- Services publics — Organismes de réglementation — Procédure — Divers

Service public entendait recouvrer les dépenses encourues ou convenues liées à la rémunération du personnel à l'aide de ses tarifs — Commission de l'énergie de l'Ontario a refusé d'approuver des dépenses de 145 millions de dollars au motif que le coût de la main-d'oeuvre du fournisseur de services publics était trop élevé — Service public a interjeté appel — Cour divisionnaire de l'Ontario a rejeté l'appel du service public — Cour d'appel a accueilli l'appel du service public —

Commission a formé un pourvoi devant la Cour suprême du Canada — Pourvoi accueilli — Commission n'a pas agi de manière inappropriée en plaidant en appel en faveur du caractère raisonnable de sa décision — Commission était la seule partie intimée lors du contrôle judiciaire initial de sa décision et n'avait d'autre choix que de prendre part à l'instance pour que sa décision soit défendue au fond — Commission a exercé sa fonction de réglementation en établissant les paiements justes et raisonnables auxquels un service public avait droit — Arguments que la Commission a invoqués en appel n'équivalaient pas à une autojustification inadmissible.

Droit public --- Services publics — Organismes de réglementation — Réglementation des tarifs

Service public entendait recouvrer les dépenses de 145 millions de dollars encourues ou convenues liées à la rémunération du personnel à l'aide de ses tarifs — Commission de l'énergie de l'Ontario a refusé d'approuver la réclamation du service public au motif que le coût de la main-d'oeuvre du service public était trop élevé — Cour divisionnaire de l'Ontario a rejeté l'appel du service public — Cour d'appel a accueilli l'appel du service public — Commission a formé un pourvoi devant la Cour suprême du Canada — Pourvoi accueilli — Commission n'a pas agi de manière déraisonnable en n'appliquant pas le critère de l'investissement prudent — Loi de 1998 sur la Commission de l'énergie de l'Ontario impose au service public requérant d'établir que les paiements qu'il demande à la Commission d'approuver sont justes et raisonnables — Lorsqu'un texte législatif exige seulement que l'organisme de réglementation fixe des paiements « justes et raisonnables », ce dernier peut avoir recours à divers moyens d'analyse pour apprécier le caractère juste et raisonnable des paiements proposés par le service public, ce qui est particulièrement vrai lorsque l'organisme de réglementation se voit accorder expressément un pouvoir discrétionnaire quant à la méthode à appliquer pour fixer les paiements — Dépenses de rémunération en l'espèce étaient en partie des dépenses convenues et en partie des dépenses relevant du pouvoir discrétionnaire de la direction — Il était déraisonnable de considérer qu'il s'agissait en totalité de dépenses prévues, mais la Commission n'était pas tenue d'appliquer un principe de prudence donné pour apprécier les dépenses — Il n'est pas nécessairement déraisonnable, à la lumière du cadre réglementaire établi par la Loi, que la Commission se prononce sur les dépenses convenues en employant une autre méthode que l'application d'un critère de prudence qui exclut le recul — Commission n'entendait aucunement, par sa décision, contraindre le service public à se soustraire à ses engagements contractuels envers ses employés syndiqués.

Droit du travail et de l'emploi --- Droit du travail — Convention collective — Divers

Service public entendait recouvrer les dépenses de 145 millions de dollars encourues ou convenues liées à la rémunération du personnel à l'aide de ses tarifs — Commission de l'énergie de l'Ontario a refusé d'approuver la réclamation du service public au motif que le coût de la main-d'oeuvre du service public était trop élevé — Cour divisionnaire de l'Ontario a rejeté l'appel du service public — Cour d'appel a accueilli l'appel du service public — Commission a formé un pourvoi devant la Cour suprême du Canada — Pourvoi accueilli — Lorsqu'un texte législatif exige seulement que l'organisme de réglementation fixe des paiements « justes et raisonnables », ce dernier peut avoir recours à divers moyens d'analyse pour apprécier le caractère juste et raisonnable des paiements proposés par le service public, ce qui est particulièrement vrai lorsque l'organisme de réglementation se voit accorder expressément un pouvoir discrétionnaire quant à la méthode à appliquer pour fixer les paiements — Dépenses de rémunération en l'espèce étaient en partie des dépenses convenues et en partie des dépenses relevant du pouvoir discrétionnaire de la direction — Il était déraisonnable de considérer qu'il s'agissait en totalité de dépenses prévues, mais la Commission n'était pas tenue d'appliquer un principe de prudence donné pour apprécier les dépenses — Il n'est pas nécessairement déraisonnable, à la lumière du cadre réglementaire établi par la Loi de 1998 sur la Commission de l'énergie de l'Ontario, que la Commission se prononce sur les dépenses convenues en employant une autre méthode que l'application d'un critère de prudence qui exclut le recul — Commission n'entendait aucunement, par sa décision, contraindre le service public à se soustraire à ses engagements contractuels envers ses employés syndiqués.

Droit administratif --- Norme de contrôle — Divers

Service public entendait recouvrer les dépenses encourues ou convenues liées à la rémunération du personnel à l'aide de ses tarifs — Commission de l'énergie de l'Ontario a refusé d'approuver des dépenses de 145 millions de dollars au motif que le coût de la main-d'oeuvre du fournisseur de services publics était trop élevé — Cour divisionnaire de l'Ontario a rejeté l'appel du service public — Cour d'appel a accueilli l'appel du service public — Commission a formé un pourvoi devant la Cour suprême du Canada — Pourvoi accueilli pour d'autres motifs — Norme de contrôle qui s'applique aux actes de la Commission lorsqu'elle fait appel à son expertise pour fixer les tarifs et approuver des paiements sur le fondement de

la Loi de 1998 sur la Commission de l'énergie de l'Ontario est celle de la décision raisonnable — Dans la mesure où l'issue du pourvoi repose sur l'interprétation de la Loi, l'application de la norme de la décision raisonnable doit être présumée.
The Ontario Energy Board disallowed $145 million in labour compensation costs claimed for a utility's nuclear operations on the grounds that the utility's labour costs were out of step with those of comparable entities in the regulated power generation industry. The utility appealed, alleging the Board should have assessed the reasonableness of the utility's decisions to incur or commit to the labour costs at the time those decisions were made. The utility also argued that it should benefit from a presumption that the costs were prudent.
The Divisional Court dismissed the appeal and upheld the Board's decision. The utility then appealed to the Court of Appeal, which set aside the decisions of the Divisional Court and the Board and remitted the matter to the Board for redetermination.
The Board appealed to the Supreme Court of Canada.
Held: The appeal was allowed. The Court of Appeal's decision was set aside and the Board's decision was reinstated.
Per Rothstein J. (McLachlin C.J.C. and Cromwell, Moldaver, Karakatsanis and Gascon JJ. concurring): The appeal was allowed. The Board did not act improperly in pursuing the matter on appeal; nor did it act unreasonably in disallowing the compensation costs.
The Board's participation in the appeal was not improper. The Board was the only respondent in the initial review of its decision, and had no alternative but to step in if the decision was to be defended on the merits. The arguments raised by the Board on appeal did not amount to impermissible bootstrapping.
The Ontario Energy Board Act, 1998 does not prescribe the methodology the Board must use to weigh utility and consumer interests when deciding what constitutes just and reasonable payment amounts to the utility. However, the Act places the burden on the utility to establish that payments amounts approved by the Board are just and reasonable.
The Board did not act unreasonably in not applying the prudent investment test. Where a statute requires only that the regulator set "just and reasonable" payments, the regulator may use a variety of tools in assessing the justness and reasonableness of payments, particularly where the regulator has been given express discretion over the methodology for setting payment amounts. The costs in this case were partly committed costs and partly costs subject to management discretion. The Board was not bound to apply a particular prudence test in evaluating these costs. It is not necessarily unreasonable, in light of the regulatory structure in the Act, for the Board to evaluate committed costs using a method other than a no-hindsight prudence review. Applying a presumption of prudence would have conflicted with the burden of proof in the Act and would not have been reasonable.
The Board's decision did not purport to force the utility to break its contractual commitments to unionized employees. It was not unreasonable for the Board to adopt a mixed approach that did not rely on quantifying the exact share of compensation costs that fell into the forecast and committed categories.
Per Abella J. (dissenting): The appeal should have been dismissed. The Board unreasonably failed to apply the methodology set out for itself for evaluating just and reasonable payment amounts. It ignored the legally binding nature of the collective agreements between the utility and the unions, and failed to distinguish between committed compensation costs and those that were reducible. The Board's failure to separately assess the compensation costs committed as a result of the collective agreements from other compensation costs, ignored not only its own methodological template, but labour law as well.
The collective agreements made it illegal for the utility to alter the compensation and staffing levels of 90 per cent of its workforce in a manner inconsistent with its commitments. The Board, however, applying the methodology it said it would use for the utility's forecast costs, put the onus on the utility to prove the reasonableness of its compensation costs and concluded that it had failed to do so. Had the Board used the approach it said it would use for costs the company had no opportunity to reduce, it would have used an after-the-fact prudence review, with a rebuttable presumption that the utility's expenditures were reasonable.
There was no evidence setting out what proportion of the utility's compensation costs were fixed and what proportion was subject to the utility's discretion. Given that collective agreements are legally binding, it was unreasonable for the Board to assume the utility could reduce the costs fixed by these contracts absent any evidence to that effect. Blaming collective bargaining for what were assumed to be excessive costs, imposed the appearance of an ideologically-driven conclusion on what was intended to be a principled methodology based on a distinction between committed and forecast

costs, not between costs which are collectively bargained and those which are not. The Board has wide discretion to fix payment amounts that are just and reasonable and to establish the methodology to determine such amounts, but once the Board establishes a methodology, it is required to apply it.

La Commission de l'énergie de l'Ontario a refusé d'approuver des dépenses de 145 millions de dollars au titre de la rémunération du personnel affecté aux installations nucléaires au motif que le coût de la main-d'oeuvre du fournisseur de services publics était en rupture avec celui d'organismes comparables dans le secteur réglementé de la production d'énergie. Le fournisseur a interjeté appel, faisant valoir que la Commission aurait dû déterminer si, au moment où elles ont été prises, les décisions prises par le fournisseur de faire les dépenses ou de convenir des dépenses étaient raisonnables. Le fournisseur a également fait valoir qu'une présomption de prudence doit s'appliquer à son bénéfice.

La Cour divisionnaire de l'Ontario a rejeté l'appel et confirmé la décision de la Commission. Le fournisseur a interjeté appel devant la Cour d'appel, laquelle a annulé les décisions de la Cour divisionnaire et la Commission et renvoyé le dossier à la Commission pour réexamen.

La Commission a formé un pourvoi devant la Cour suprême du Canada.

Arrêt: Le pourvoi a été accueilli; la décision de la Cour d'appel a été annulée et la décision de la Commission a été rétablie.

Rothstein, J. (McLachlin, J.C.C., Cromwell, Moldaver, Karakatsanis, Gascon, JJ., souscrivant à son opinion) : Le pourvoi a été accueilli. La Commission n'a pas agi de manière inappropriée en se pourvoyant en appel et n'a pas non plus agi déraisonnablement en refusant d'approuver les dépenses de rémunération en cause.

La participation de la Commission au pourvoi n'avait rien d'inapproprié. La Commission était la seule partie intimée lors du contrôle judiciaire initial de sa décision et n'avait d'autre choix que de prendre part à l'instance pour que sa décision soit défendue au fond. Les arguments qu'elle a invoqués en appel n'équivalaient pas à une autojustification inadmissible.

La Loi de 1998 sur la Commission de l'énergie de l'Ontario ne prescrit pas la méthode que doit utiliser la Commission pour soupeser les intérêts respectifs du service public et du consommateur lorsqu'elle décide ce qui constitue des paiements justes et raisonnables au service public. Suivant cette loi, il incombe cependant au service public requérant d'établir que les paiements qu'il demande à la Commission d'approuver sont justes et raisonnables.

La Commission n'a pas agi de manière déraisonnable en n'appliquant pas le critère de l'investissement prudent. Lorsqu'un texte législatif exige seulement que l'organisme de réglementation fixe des paiements « justes et raisonnables », ce dernier peut avoir recours à divers moyens d'analyse pour apprécier le caractère juste et raisonnable des paiements, ce qui est particulièrement vrai lorsque l'organisme de réglementation se voit accorder expressément un pouvoir discrétionnaire quant à la méthode à appliquer pour fixer les paiements. Il convenait de voir dans les dépenses de rémunération en l'espèce en partie des dépenses convenues et en partie des dépenses relevant du pouvoir discrétionnaire de la direction.

La Commission n'était pas tenue d'appliquer un principe de prudence donné pour apprécier les dépenses. Il n'est pas nécessairement déraisonnable, à la lumière du cadre réglementaire établi par la Loi, que la Commission se prononce sur les dépenses convenues en employant une autre méthode que l'application d'un critère de prudence qui exclut le recul. Présumer la prudence aurait été incompatible avec le fardeau de la preuve que prévoit la Loi et, de ce fait, déraisonnable.

La Commission n'entendait aucunement, par sa décision, contraindre le service public à se soustraire à ses engagements contractuels envers ses employés syndiqués. Il n'était pas déraisonnable que la Commission opte pour une démarche hybride qui ne se fonde pas sur la répartition exacte des dépenses de rémunération entre celles qui sont prévues et celles qui sont convenues.

Abella, J. (dissidente) : Le pourvoi aurait dû être rejeté. La Commission a rendu une décision déraisonnable en ce qu'elle n'a pas appliqué la méthode qu'elle avait elle-même établie pour déterminer le montant de paiements justes et raisonnables. Elle a à la fois méconnu le caractère contraignant en droit des conventions collectives liant le service public et les syndicats et omis de distinguer les dépenses de rémunération convenues de celles qui étaient réductibles. Par son omission d'apprécier les dépenses de rémunération issues des conventions collectives séparément des autres dépenses de rémunération, la Commission a méconnu à la fois son propre cadre méthodologique et le droit du travail.

Les conventions collectives rendaient illégale la modification par le service public, d'une manière incompatible avec les engagements qu'il y prenait, des barèmes de rémunération et des niveaux de dotation quant à 90 p. cent de son effectif obligatoire. Or, en appliquant la méthode qu'elle avait dit qu'elle utiliserait à l'égard des dépenses prévues du service public, la Commission a en fait obligé le service public à prouver le caractère raisonnable de toutes ses dépenses de rémunération et a conclu que l'entreprise n'y était pas arrivé. Si elle avait eu recours à l'approche qu'elle avait dit qu'elle utiliserait pour les dépenses à l'égard desquelles la société ne pouvait prendre de mesures de réduction, la Commission aurait contrôlé la prudence des dépenses après coup et appliqué la présomption réfutable selon laquelle elles étaient raisonnables.

Aucune preuve n'indiquait dans quelle proportion les dépenses de rémunération du service public étaient fixes et dans quelle proportion elles demeuraient assujetties au pouvoir discrétionnaire de ce dernier. Comme les conventions collectives sont contraignantes en droit, il était déraisonnable que la Commission présume que le service public pouvait réduire les dépenses déterminées par ces contrats en l'absence de toute preuve en ce sens. Imputer à la négociation collective ce que l'on suppose constituer des dépenses excessives revenait à substituer ce qui a l'apparence d'une conclusion idéologique à ce qui était censé résulter d'une méthode d'analyse raisonnée qui distingue entre les dépenses convenues et les dépenses prévues, non entre les dépenses issues de négociations collectives et celles qui ne le sont pas. La Commission jouit d'un vaste pouvoir discrétionnaire lui permettant de déterminer les paiements qui sont justes et raisonnables et de définir la méthode utilisée pour établir le montant de ces paiements, mais dès lors qu'elle a établi une méthode pour déterminer ce qui est juste et raisonnable, la Commission doit à tout le moins l'appliquer avec constance.

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A.T.A. v. Alberta (Information & Privacy Commissioner) (2011), 2011 SCC 61, 2011 CarswellAlta 2068, 2011 CarswellAlta 2069, 339 D.L.R. (4th) 428, 28 Admin. L.R. (5th) 177, 52 Alta. L.R. (5th) 1, [2012] 2 W.W.R. 434, (sub nom. *Alberta Teachers' Association v. Information & Privacy Commissioner (Alta.)*) 424 N.R. 70, (sub nom. *Alberta (Information & Privacy Commissioner) v. Alberta Teachers' Association*) [2011] 3 S.C.R. 654, (sub nom. *Alberta Teachers' Association v. Information and Privacy Commissioner*) 519 A.R. 1, (sub nom. *Alberta Teachers' Association v. Information and Privacy Commissioner*) 539 W.A.C. 1 (S.C.C.) — referred to

ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board) (2006), 2006 SCC 4, 2006 CarswellAlta 139, 2006 CarswellAlta 140, 344 N.R. 293, 54 Alta. L.R. (4th) 1, [2006] 5 W.W.R. 1, 263 D.L.R. (4th) 193, 39 Admin. L.R. (4th) 159, 380 A.R. 1, 363 W.A.C. 1, [2006] 1 S.C.R. 140 (S.C.C.) — considered

B.C.G.E.U. v. British Columbia (Industrial Relations Council) (1988), 26 B.C.L.R. (2d) 145, 32 Admin. L.R. 78, 1988 CarswellBC 174 (B.C. C.A.) — considered

Bell Canada v. Canadian Radio-Television & Telecommunications Commission (2009), 2009 SCC 40, 2009 CarswellNat 2717, 2009 CarswellNat 2718, 92 Admin. L.R. (4th) 157, (sub nom. *Consumers Association of Canada v. Canadian Radio-Television and Telecommunications Commission*) 392 N.R. 323, 310 D.L.R. (4th) 608, (sub nom. *Bell Canada v. Bell Aliant Regional Communications*) [2009] 2 S.C.R. 764 (S.C.C.) — considered

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British Columbia (Securities Commission) v. McLean (2013), 2013 SCC 67, 2013 CarswellBC 3618, 2013 CarswellBC 3619, 366 D.L.R. (4th) 30, [2014] 2 W.W.R. 415, (sub nom. *McLean v. British Columbia Securities Commission*) 452 N.R. 340, 53 B.C.L.R. (5th) 1, (sub nom. *McLean v. British Columbia (Securities Commission)*) [2013] 3 S.C.R. 895, (sub nom. *McLean v. British Columbia Securities Commission*) 347 B.C.A.C. 1, (sub nom. *McLean v. British Columbia Securities Commission*) 593 W.A.C. 1, 64 Admin. L.R. (5th) 237 (S.C.C.) — referred to

British Columbia Electric Railway v. British Columbia (Public Utilities Commission) (1960), [1960] S.C.R. 837, 33 W.W.R. 97, 82 C.R.T.C. 32, 25 D.L.R. (2d) 689, 1960 CarswellBC 94 (S.C.C.) — considered

C.A.I.M.A.W., Local 14 v. Canadian Kenworth Co. (1989), [1989] 2 S.C.R. 983, (sub nom. *C.A.I.M.A.W. v. Paccar of Canada Ltd.*) [1989] 6 W.W.R. 673, (sub nom. *C.A.I.M.A.W. v. Paccar of Canada Ltd.*) 62 D.L.R. (4th) 437, (sub nom. *Paccar of Canada Ltd. v. C.A.I.M.A.W., Local 14*) 102 N.R. 1, (sub nom. *C.A.I.M.A.W. v. Paccar of Canada Ltd.*) 40 B.C.L.R. (2d) 1, 40 Admin. L.R. 181, (sub nom. *Paccar of Canada Ltd. v. C.A.I.M.A.W., Local 14*) 89 C.L.L.C. 14,050, (sub nom. *Paccar of Canada Ltd., Canadian Kenworth Division v. C.A.I.M.A.W., Local 14*) 1989 CarswellBC 174, 1989 CarswellBC 716 (S.C.C.) — considered

Chandler v. Assn. of Architects (Alberta) (1989), [1989] 6 W.W.R. 521, 36 C.L.R. 1, [1989] 2 S.C.R. 848, 70 Alta. L.R. (2d) 193, 40 Admin. L.R. 128, 62 D.L.R. (4th) 577, 99 N.R. 277, 101 A.R. 321, 1989 CarswellAlta 160, 1989 CarswellAlta 620 (S.C.C.) — referred to

Children's Lawyer for Ontario v. Goodis (2005), 2005 CarswellOnt 1419, 196 O.A.C. 350, (sub nom. *Ontario (Children's Lawyer) v. Ontario (Information & Privacy Commissioner)*) 253 D.L.R. (4th) 489, (sub nom. *Ontario (Children's Lawyer) v. Ontario (Information & Privacy Commissioner)*) 75 O.R. (3d) 309, 29 Admin. L.R. (4th) 86, 17 R.F.L. (6th) 32 (Ont. C.A.) — considered

Commissioner of Competition v. CCS Corp. (2015), 2015 SCC 3, 2015 CSC 3, 2015 CarswellNat 32, 2015 CarswellNat 33, 380 D.L.R. (4th) 381, 79 Admin. L.R. (5th) 1, (sub nom. *Tervita Corp. v. Commissioner of Competition*) 467 N.R. 97, (sub nom. *Tervita Corp. v. Canada (Commissioner of Competition)*) [2015] 1 S.C.R. 161 (S.C.C.) — referred to

Duquesne Light Co. v. Barasch (1989), 488 U.S. 299, 98 P.U.R. 4th 253, 109 S.Ct. 609, 102 L.Ed.2d 646, 57 U.S.L.W. 4083 (U.S. Sup. Ct.) — considered

Edmonton (City) v. Northwestern Utilities Ltd. (1929), [1929] S.C.R. 186, [1929] 2 D.L.R. 4, 1929 CarswellAlta 114 (S.C.C.) — considered

Enbridge Gas Distribution Inc. v. Ontario (Energy Board) (2006), 2006 CarswellOnt 2106, 41 Admin. L.R. (4th) 69, 210 O.A.C. 4 (Ont. C.A.) — referred to

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I.B.E.W., Local 894 v. Ellis-Don Ltd. (2001), 2001 SCC 4, 2001 CarswellOnt 99, 2001 CarswellOnt 100, (sub nom. *Ellis-Don Ltd. v. Ontario (Labour Relations Board)*) 194 D.L.R. (4th) 385, (sub nom. *Ellis-Don Ltd. v. Labour Relations Board (Ont.)*) 265 N.R. 2, (sub nom. *Ellis-Don Ltd. v. Ontario Labour Relations Board*) 52 O.R. (3d) 160 (note), (sub nom. *Ellis-Don Ltd. v. Ontario Labour Relations Board*) 2001 C.L.L.C. 220-028, 26 Admin. L.R. (3d) 171, (sub nom. *Ellis-Don Ltd. v. Labour Relations Board*) 140 O.A.C. 201, (sub nom. *Ellis-Don Ltd. v. Ontario (Labour Relations Board)*) [2001] 1 S.C.R. 221, [2001] O.L.R.B. Rep. 236, (sub nom. *Ellis-Don Ltd. v. Ontario (Labour Relations Board)*) 66 C.L.R.B.R. (2d) 216, 2001 CSC 4 (S.C.C.) — referred to

Leon's Furniture Ltd. v. Alberta (Information & Privacy Commissioner) (2011), 2011 ABCA 94, 2011 CarswellAlta 453, 22 Admin. L.R. (5th) 11, 45 Alta. L.R. (5th) 1, [2011] 9 W.W.R. 668, 502 A.R. 110, 517 W.A.C. 110 (Alta. C.A.) — considered

New Brunswick (Board of Management) v. Dunsmuir (2008), 2008 SCC 9, 2008 CarswellNB 124, 2008 CarswellNB 125, D.T.E. 2008T-223, (sub nom. *Dunsmuir v. New Brunswick*) 2008 C.L.L.C. 220-020, 64 C.C.E.L. (3d) 1, 69 Imm. L.R. (3d) 1, 69 Admin. L.R. (4th) 1, 372 N.R. 1, (sub nom. *Dunsmuir v. New Brunswick*) 170 L.A.C. (4th) 1, (sub nom. *Dunsmuir v. New Brunswick*) 291 D.L.R. (4th) 577, 329 N.B.R. (2d) 1, (sub nom. *Dunsmuir v. New Brunswick*) [2008] 1 S.C.R. 190, 844 A.P.R. 1, (sub nom. *Dunsmuir v. New Brunswick*) 95 L.C.R. 65, 2008 CSC 9 (S.C.C.) — referred to

Northwestern Utilities Ltd., Re (1978), [1979] 1 S.C.R. 684, (sub nom. *Northwestern Utilities Ltd. v. Edmonton (City)*) 7 Alta. L.R. (2d) 370, (sub nom. *Northwestern Utilities Ltd. v. Edmonton (City)*) 12 A.R. 449, (sub nom. *Northwestern Utilities Ltd. v. Edmonton (City)*) 89 D.L.R. (3d) 161, (sub nom. *Northwestern Utilities Ltd. v. Edmonton (City)*) 23 N.R. 565, 1978 CarswellAlta 141, 1978 CarswellAlta 303 (S.C.C.) — considered

Nova Scotia Power Inc., Re (2005), 2005 NSUARB 27, 2005 CarswellNS 656 (N.S. Utility & Review Bd.) — considered

Nova Scotia Power Inc., Re (2012), 2012 NSUARB 227, 2012 CarswellNS 927 (N.S. Utility & Review Bd.) — considered

Quadrini v. Canada (Revenue Agency) (2010), 2010 FCA 246, 2010 CarswellNat 3525, (sub nom. *Canada (Attorney General) v. Quadrini*) 409 N.R. 141, 2010 CAF 246, 2010 CarswellNat 5713, (sub nom. *Canada (Attorney General) v. Quadrini*) [2012] 2 F.C.R. 3 (F.C.A.) — considered

Québec (Commission des affaires sociales) c. Tremblay (1992), 3 Admin. L.R. (2d) 173, [1992] 1 S.C.R. 952, 47 Q.A.C. 169, 136 N.R. 5, 90 D.L.R. (4th) 609, 1992 CarswellQue 108, 1992 CarswellQue 114 (S.C.C.) — referred to

State of Missouri ex rel. Southwestern Bell Telephone Co. v. Public Service Commission of Missouri (1923), 262 U.S. 276, 43 S.Ct. 544, 67 L.Ed. 981 (U.S. Mo. S.C.) — considered

Toronto Hydro-Electric System Ltd. v. Ontario (Energy Board) (2010), 2010 ONCA 284, 2010 CarswellOnt 2353, 99 O.R. (3d) 481, 317 D.L.R. (4th) 247, 68 B.L.R. (4th) 159, 261 O.A.C. 306 (Ont. C.A.) — referred to

TransCanada Pipelines Ltd. v. Canada (National Energy Board) (2004), 2004 FCA 149, 2004 CarswellNat 987, 319 N.R. 171, 2004 CAF 149, 2004 CarswellNat 2545 (F.C.A.) — referred to

US West Communications Inc. v. Public Service Commission of Utah (1995), 901 P.2d 270 (U.S. Utah S.C.) — considered

Cases considered by *Abella J.* (dissenting):

Edmonton (City) v. Northwestern Utilities Ltd. (1929), [1929] S.C.R. 186, [1929] 2 D.L.R. 4, 1929 CarswellAlta 114 (S.C.C.) — refered to in a minority or dissenting opinion

Enbridge Gas Distribution Inc. v. Ontario (Energy Board) (2006), 2006 CarswellOnt 2106, 41 Admin. L.R. (4th) 69, 210 O.A.C. 4 (Ont. C.A.) — refered to in a minority or dissenting opinion

Ontario Power Generation v. Society of Energy Professionals (2011), 2011 CarswellOnt 1969 (Ont. Arb.) — refered to in a minority or dissenting opinion

State of Missouri ex rel. Southwestern Bell Telephone Co. v. Public Service Commission of Missouri (1923), 262 U.S. 276, 43 S.Ct. 544, 67 L.Ed. 981 (U.S. Mo. S.C.) — considered in a minority or dissenting opinion

TransCanada Pipelines Ltd. v. Canada (National Energy Board) (2004), 2004 FCA 149, 2004 CarswellNat 987, 319 N.R. 171, 2004 CAF 149, 2004 CarswellNat 2545 (F.C.A.) — refered to in a minority or dissenting opinion

Verizon Communications Inc. v. Federal Communications Commission (2002), 535 U.S. 467, 122 S.Ct. 1646 (U.S. Sup. Ct.) — refered to in a minority or dissenting opinion

Statutes considered by *Rothstein J.*:

Nuclear Safety and Control Act, S.C. 1997, c. 9

Generally — referred to

Ontario Energy Board Act, 1998, S.O. 1998, c. 15, Sched. B

Generally — referred to

s. 1 — referred to

s. 1(1) ¶ 1 — considered

s. 1(1) ¶ 2 — considered

s. 33(3) — referred to

s. 78.1 [en. 2004, c. 23, Sched. B, s. 15] — referred to

s. 78.1(5) [en. 2004, c. 23, Sched. B, s. 15] — considered

s. 78.1(6) [en. 2004, c. 23, Sched. B, s. 15] — considered

s. 78.1(7) [en. 2004, c. 23, Sched. B, s. 15] — considered

Public Utilities Act, R.S.B.C. 1948, c. 277

s. 16(1)(b) — referred to

Statutes considered by *Abella J.* (dissenting):

Labour Relations Act, 1995, S.O. 1995, c. 1, Sched. A

s. 69 — referred to

s. 56 — referred to

Nuclear Safety and Control Act, S.C. 1997, c. 9

Generally — referred to

Ontario Energy Board Act, 1998, S.O. 1998, c. 15, Sched. B

s. 1(1) ¶ 1 — referred to

s. 1(1) ¶ 2 — referred to

s. 78.1 [en. 2004, c. 23, Sched. B, s. 15] — referred to

s. 78.1(2) [en. 2004, c. 23, Sched. B, s. 15] — referred to

s. 78.1(5) [en. 2004, c. 23, Sched. B, s. 15] — considered

s. 78.1(6) [en. 2004, c. 23, Sched. B, s. 15] — considered

Regulations considered by *Rothstein J.*:

Ontario Energy Board Act, 1998, S.O. 1998, c. 15, Sched. B

Payments under Section 78.1 of the Act, O. Reg. 53/05

Generally — referred to

s. 6(1) — considered

s. 6(2) — considered

s. 6(2) ¶ 4.1 [en. O. Reg. 27/08] — considered

Regulations considered by *Abella J.* (dissenting):

Ontario Energy Board Act, 1998, S.O. 1998, c. 15, Sched. B

Payments under Section 78.1 of the Act, O. Reg. 53/05

s. 6 — referred to

s. 6(1) — referred to

Words and phrases considered:

OPG

OPG [Ontario Power Generation] is Ontario's largest energy generator, and is subject to rate regulation by the [Ontario Energy] Board. OPG came into being in 1999 as one of the successor corporations to Ontario Hydro. It operates Board-regulated nuclear and hydroelectric facilities . . . Its sole shareholder is the Province of Ontario.

bootstrapping

[I]n the context of tribunal standing, a tribunal engages in bootstrapping where it seeks to supplement what would otherwise be a deficient decision with new arguments on appeal . . .

forecast costs

Forecast costs are costs which the utility has not yet paid, and over which the utility still retains discretion as to whether the disbursement will be made.

prudent investment test

The prudent investment test, or prudence review, is a valid and widely accepted tool that regulators may use when assessing whether payments to a utility would be just and reasonable.

Termes et locutions cités:

Ontario Power Generation

OPG [(Ontario Power Generation)] est le plus grand producteur d'énergie de l'Ontario, et sa tarification est réglementée par la Commission. Elle a vu le jour en 1999 et fait partie des entreprises qui ont succédé à Ontario Hydro. Elle exploite des installations nucléaires et hydroélectriques soumises à la réglementation de la Commission (...). Son unique actionnaire est la province d'Ontario.

autojustification

Suivant le sens attribué à cette notion par les cours de justice qui l'ont examinée dans le contexte de la qualité pour agir, un tribunal « s'autojustifie » lorsqu'il cherche, par la présentation de nouveaux arguments en appel, à étoffer une décision qui, sinon, serait lacunaire (...).

critère de l'investissement prudent

Le critère de l'investissement prudent - ou contrôle de la prudence - offre aux organismes de réglementation un moyen valable et largement reconnu d'apprécier le caractère juste et raisonnable des paiements sollicités par un service public.

dépenses prévues

Les dépenses prévues sont celles que le service public n'a pas encore acquittées et qu'un pouvoir discrétionnaire lui permet de renoncer à faire.

APPEAL by Ontario Energy Board from judgment of Court of Appeal reported at *Hydro One Networks Inc., Re* (2013), 2013 ONCA 359, 2013 CarswellOnt 9792, 307 O.A.C. 109, 116 O.R. (3d) 793, 365 D.L.R. (4th) 247 (Ont. C.A.), setting aside Divisional Court decision setting aside Board's decision regarding rate application.

POURVOI formé par la Commission de l'énergie de l'Ontario à l'encontre d'une décision publiée à *Hydro One Networks Inc., Re* (2013), 2013 ONCA 359, 2013 CarswellOnt 9792, 307 O.A.C. 109, 116 O.R. (3d) 793, 365 D.L.R. (4th) 247 (Ont. C.A.), ayant annulé la décision de la Cour divisionnaire ayant elle-même annulé la décision de la Commission au sujet de l'application du tarif.

***Rothstein J.* (McLachlin C.J.C., Cromwell, Moldaver, Karakatsanis and Gascon JJ. concurring):**

1 In Ontario, utility rates are regulated through a process by which a utility seeks approval from the Ontario Energy Board ("Board") for costs the utility has incurred or expects to incur in a specified period of time. Where the Board approves of costs, they are incorporated into utility rates such that the utility receives payment amounts to cover the approved expenditures. This case concerns the decision of the Board to disallow certain payment amounts applied for by Ontario Power Generation Inc. ("OPG") as part of its rate application covering the 2011-2012 operating period. Specifically, the Board disallowed $145 million in labour compensation costs related to OPG's nuclear operations on the grounds that OPG's labour costs were out of step with those of comparable entities in the regulated power generation industry.

2 OPG appealed the Board's decision to the Ontario Divisional Court. A majority of the court dismissed the appeal and upheld the decision of the Board. OPG then appealed that decision to the Ontario Court of Appeal, which set aside the decisions of the Divisional Court and the Board and remitted the matter to the Board for redetermination in accordance with its reasons. The Board now appeals to this Court.

3 OPG asserts that the Board's decision to disallow these labour compensation costs was unreasonable. The crux of OPG's argument is that the Board is legally required to compensate OPG for all of its prudently committed or incurred costs. OPG asserts that prudence in this context has a particular methodological meaning that requires the Board to assess the reasonableness of OPG's decisions to incur or commit to costs at the time the decisions to incur or commit to the costs were made and that OPG ought to benefit from a presumption of prudence. Because the Board did not employ this prudence methodology, OPG argues that its decision was unreasonable.

4 The Board argues that a particular "prudence test" methodology is not compelled by law, and that in any case the costs disallowed here were not "committed" nuclear compensation costs, but are better characterized as forecast costs.

5 OPG also raises concerns regarding the Board's role in acting as a party on appeal from its own decision. OPG argues that in this case, the Board's aggressive and adversarial defence of its original decision was improper, and that the Board attempted to use the appeal to "bootstrap" its original decision by making additional arguments on appeal.

6 The Board asserts that the scope of its authority to argue on appeal was settled when it was granted full party rights in connection with the granting of leave by this Court. Alternatively, the Board argues that the structure of utilities regulation in Ontario makes it necessary and important for it to argue the merits of its decisions on appeal.

7 In my opinion, the labour compensation costs which led to the $145 million disallowance are best understood as partly committed costs and partly costs subject to management discretion. They are partly committed because they resulted from collective agreements entered into between OPG and two of its unions, and partly subject to management discretion because OPG retained some flexibility to manage total staffing levels in light of, among other things, projected attrition of the workforce. It is not reasonable to treat these costs as entirely forecast. However, I do not agree with OPG that the Board was bound to apply a particular prudence test in evaluating these costs. The *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Sch. B, and associated regulations give the Board broad latitude to determine the methodology it uses in assessing utility costs, subject to the Board's ultimate duty to ensure that payment amounts it orders be just and reasonable to both the utility and consumers.

8 In this case, the nature of the disputed costs and the environment in which they arose provide a sufficient basis to find that the Board did not act unreasonably in disallowing the costs.

9 Regarding the Board's role on appeal, I do not find that the Board acted improperly in arguing the merits of this case, nor do I find that the arguments raised on appeal amount to impermissible "bootstrapping".

10 Accordingly, I would allow the appeal, set aside the decision of the Court of Appeal, and reinstate the decision of the Board.

I. Regulatory Framework

11 The *Ontario Energy Board Act, 1998* establishes the Board as a regulatory body with authority to oversee, among other things, electricity generation in the province of Ontario. Section 1 sets out the objectives of the Board in regulating electricity, which include:

> **1.**(1) . . .
>
> > 1. To protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service.
> >
> > 2. To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry.

Accordingly, the Board must ensure that it regulates with an eye to balancing both consumer interests and the efficiency and financial viability of the electricity industry. The Board's role has also been described as that of a "market proxy": 2012 ONSC 729, 109 O.R. (3d) 576 (Ont. Div. Ct.), at para. 54; 2013 ONCA 359, 116 O.R. (3d) 793 (Ont. C.A.), at para. 38. In this sense, the Board's role is to emulate as best as possible the forces to which a utility would be subject in a competitive landscape: *Toronto Hydro-Electric System Ltd. v. Ontario (Energy Board)*, 2010 ONCA 284, 99 O.R. (3d) 481 (Ont. C.A.), at para. 48.

12 One of the Board's most powerful tools to achieve its objectives is its authority to fix the amount of payments utilities receive in exchange for the provision of service. Section 78.1(5) of the *Ontario Energy Board Act, 1998* provides in relevant part:

> (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; ...

13 Section 78.1(6) provides: "... the burden of proof is on the applicant in an application made under this section".

14 As I read these provisions, the utility applies for payment amounts for a future period (called the "test period"). The Board will accept the payment amounts applied for unless the Board is not satisfied that amounts are just and reasonable. Where the Board is not satisfied, s. 78.1(5) empowers it to fix other payment amounts which it finds to be just and reasonable.

15 This Court has had the occasion to consider the meaning of similar statutory language in *Edmonton (City) v. Northwestern Utilities Ltd.*, [1929] S.C.R. 186 (S.C.C.). In that case, the Court held that "fair and reasonable" rates were those "which, under the circumstances, would be fair to the consumer on the one hand, and which, on the other hand, would secure to the company a fair return for the capital invested" (pp. 192-93).

16 This means that the utility must, over the long run, be given the opportunity to recover, through the rates it is permitted to charge, its operating and capital costs ("capital costs" in this sense refers to all costs associated with the utility's invested capital). This case is concerned primarily with operating costs. If recovery of operating costs is not permitted, the utility will not earn its cost of capital, which represents the amount investors require by way of a return on their investment in order to justify an investment in the utility. The required return is one that is equivalent to what they could earn from an investment of comparable risk. Over the long run, unless a regulated utility is allowed to earn its cost of capital, further investment will be discouraged and it will be unable to expand its operations or even maintain existing ones. This will harm not only its shareholders, but also its customers: *TransCanada Pipelines Ltd. v. Canada (National Energy Board)*, 2004 FCA 149, 319 N.R. 171 (F.C.A.).

17 This of course does not mean that the Board must accept every cost that is submitted by the utility, nor does it mean that the rate of return to equity investors is guaranteed. In the short run, return on equity may vary, for example if electricity consumption by the utility's customers is higher or lower than predicted. Similarly, a disallowance of any operating costs to which the utility has committed itself will negatively impact the return to equity investors. I do not intend to enter into a detailed analysis of how the cost of equity capital should be treated by utility regulators, but merely to observe that any disallowance of costs to which a utility has committed itself has an effect on equity investor returns. This effect must be carefully considered in light of the long-run necessity that utilities be able to attract investors and retain earnings in order to survive and operate efficiently and effectively, in accordance with the statutory objectives of the Board in regulating electricity in Ontario.

18 As noted above, the burden is on the utility to satisfy the Board that the payment amounts it applies for are just and reasonable. If it fails to do so, the Board may disallow the portion of the application that it finds is not for amounts that are just and reasonable.

19 Where applied-for operating costs are disallowed, the utility, if it is able to do so, may forego the expenditure of such costs. Where the expenditure cannot be foregone, the shareholders of the utility will have to absorb the reduction in the form of receiving less than their anticipated rate of return on their investment, i.e. the utility's cost of equity capital. In such circumstances it will be the management of the utility that will be responsible in the future for bringing its costs into line with what the Board considers just and reasonable.

20 In order to ensure that the balance between utilities' and consumers' interests is struck, just and reasonable rates must be those that ensure consumers are paying what the Board expects it to cost to efficiently provide the services they receive, taking account of both operating and capital costs. In that way, consumers may be assured that, overall, they are paying no more than what is necessary for the service they receive, and utilities may be assured of an opportunity to earn a fair return for providing those services.

II. Facts

21 OPG is Ontario's largest energy generator, and is subject to rate regulation by the Board. OPG came into being in 1999 as one of the successor corporations to Ontario Hydro. It operates Board-regulated nuclear and hydroelectric facilities that generate approximately half of Ontario's electricity. Its sole shareholder is the Province of Ontario.

22 It employs approximately 10,000 people in connection with its regulated facilities, 95 percent of whom work in its nuclear business. Approximately 90 percent of its employees in its regulated businesses are unionized, with approximately two thirds of unionized employees represented by the Power Workers' Union, Canadian Union of Public Employees, Local 1000 ("PWU"), and one third represented by the Society of Energy Professionals ("Society").

23 Since early in its existence as an independent utility, OPG has been aware of the importance of improving its corporate performance. As part of a general effort to improve its business, OPG undertook efforts to benchmark its nuclear performance against comparable power plants around the world. In a memorandum of agreement ("MOA") with the Province of Ontario dated August 17, 2005, OPG committed to the following:

> OPG will seek continuous improvement in its nuclear generation business and internal services. OPG will benchmark its performance in these areas against CANDU nuclear plants worldwide as well as against the top quartile of private and publicly-owned nuclear electricity generators in North America. OPG's top operational priority will be to improve the operation of its existing nuclear fleet.
>
> (A.R., vol. III, at p. 215)

24 As part of OPG's first-ever rate application with the Board in 2007, for a test period covering the years 2008 and 2009, OPG sought approval for a $6.4 billion "revenue requirement"; this term refers to "the total revenue that is required by the company to pay all of its allowable expenses and also to recover all costs associated with its invested capital": L. Reid and J. Todd, "New Developments in Rate Design for Electricity Distributors", in G. Kaiser and B. Heggie, eds., *Energy Law and Policy* (2011), 519, at p. 521. This constituted an increase of $1 billion over the revenue requirement that it had sought and was granted under the regulatory scheme in place prior to the Board's assumption of regulatory authority over OPG: EB-2007-0905, Decision with Reasons, November 3, 2008 (the "Board 2008-2009 Decision") (online), at pp. 5-6).

25 The Board found that OPG was not meeting the nuclear performance expectations of its sole shareholder and that it had done little to conduct benchmarking of its performance against that of its peers, despite its commitment to do so dating back to 2005. Indeed, the only evidence of benchmarking that OPG submitted as part of its rate application was a 2006 report from Navigant Consulting, Inc. (the "Navigant Report"), which found that OPG was overstaffed by 12 percent in comparison to its peers. The Board found that OPG had not acted on the recommendations of the Navigant Report and had not commissioned subsequent benchmarking studies to assess its performance (Board 2008-2009 Decision, at pp. 27 and 30). The Board also found that operating costs at OPG's Pickering nuclear facilities were "far above industry averages" (p. 29). The Board thus disallowed $35 million of OPG's proposed revenue requirement and directed OPG to prepare benchmarking studies for use in future applications (p. 31).

26 In explaining the importance of benchmarking, the Board stated: "The reason why the MOA emphasized benchmarking was because such studies can and do shine a light on inefficiencies and lack of productivity improvement" (Board 2008-2009 Decision, at p. 30).

27 On May 5, 2010, shortly before OPG was set to file its second rate application, which is the subject of this appeal, the Ontario Minister of Energy and Infrastructure wrote to the President and CEO of OPG to ensure that OPG would demonstrate in its upcoming rate application "concerted efforts to identify cost saving opportunities and focus [its] forthcoming rate application on those items that are essential to the safe and reliable operation of [its] existing assets and projects already under development" (A.R., vol. IV, at p. 38).

28 On May 26, 2010, OPG filed its payment amounts application for the 2011-2012 test period. As part of its evidence before the Board, OPG submitted two reports by ScottMadden Inc., a general management consulting firm specializing in benchmarking and business planning for nuclear facilities. The Phase 1 report compared OPG's nuclear operational and financial performance against that of external peers using industry performance metrics. The Phase 2 final report discussed performance improvement targets with the intent of improving OPG's nuclear business. OPG collaborated with ScottMadden on the Phase 1 and 2 reports, which were released on July 2, 2009 and September 11, 2009, respectively.

29 OPG's rate application pertained to a test period beginning on January 1, 2011 and ending on December 31, 2012. OPG sought approval of a $6.9 billion revenue requirement, which represented an increase of 6.2 percent over OPG's then-current revenue based on the preceding year's approved utility rates. Of the $6.9 billion revenue requirement sought by OPG, $2.8 billion pertained to compensation costs, of which approximately $2.4 billion concerned OPG's nuclear business.

30 A substantial portion of OPG's wage and compensation expenses were fixed by OPG's collective agreements with the unions, PWU and the Society. At the time of its application, OPG was party to a collective agreement with PWU, effective from April 2009 through March 2012, while its collective agreement with the Society expired on December 31, 2010. These collective agreements provided annual wage increases between 2 percent and 3 percent. OPG forecast an additional 1 percent increase for step progressions and promotions of unionized staff. Following the Board's hearing in this case, an interest arbitrator ordered a new collective agreement between OPG and the Society, effective February 3, 2011. This collective agreement provided wage increases that varied between 1 percent and 3 percent.

III. Judicial History

A. Ontario Energy Board: EB-2010-0008, Decision With Reasons, March 10, 2011 (the "Board Decision") (Online)

31 In its decision concerning OPG's rate application for the 2011-2012 test period, the Board stated that it enjoyed broad discretion pursuant to Ontario Regulation 53/05 (*Payments Under Section 78.1 of the Act*) and s. 78.1 of the *Ontario Energy Board Act, 1998* to "adopt the mechanisms it judges appropriate in setting just and reasonable rates" (p. 18). The Board recognized that different tests could apply depending on whether its analysis concerned the recovery of forecast costs or an after-the-fact review of costs already incurred. In this rate application, it was appropriate to take into consideration all evidence that the Board deemed relevant to assess the reasonableness of OPG's revenue requirement.

32 The Board rejected OPG's proposed revenue requirement of $6.9 billion, reducing it by $145 million over the test period "to send a clear signal that OPG must take responsibility for improving its performance" (p. 86). Key to its disallowance was the Board's finding that OPG was overstaffed and that its compensation levels were excessive.

33 Regarding the number of staff, the Board pointed out that a benchmarking study commissioned by OPG itself, the ScottMadden Phase 2 final report, suggested that certain staff positions could be reduced or eliminated altogether. The Board suggested that OPG could review its organizational structure and reassign or eliminate positions in the coming years, as 20 percent to 25 percent of its staff were set to retire between 2010 and 2014 and it was possible to make greater use of external contractors. Regarding compensation, the Board found that OPG had not submitted compelling evidence justifying the benchmarking of its salaries of non-management employees to the 75th percentile of a survey of industry salaries conducted by Towers Perrin. Instead, the Board considered the proper benchmark to be the 50th percentile, the same percentile against which OPG benchmarks management compensation. In determining the appropriate disallowance, the Board acknowledged that OPG may not have been able to achieve the full $145 million

in savings for the test period through the reduction of compensation levels alone because of its collective agreements with the unions.

B. Ontario Superior Court of Justice, Divisional Court: 2012 ONSC 729, 109 O.R. (3d) 576 (Ont. Div. Ct.)

34 OPG appealed the Board Decision on the basis that it was unreasonable and that the reasons provided were inadequate. OPG argued that the Board should have conducted a prudent investment test — that is, it should have restricted its review of compensation costs to a consideration of whether the collective agreements that prescribed the compensation costs were prudent at the time they were entered into. OPG also argued that the Board should have presumed that the costs were prudent.

35 The panel of three Divisional Court judges was split. Justice Hoy (as she then was), for the majority, found the Board Decision reasonable because management had the ability to reduce total compensation costs in the future within the framework of the collective agreement. Applying a strict prudent investment test would not permit the Board to fulfill its statutory objective of promoting cost effectiveness in the generation of electricity. It was particularly important for the Board to exercise its authority to set just and reasonable rates given the "double monopoly" dynamic at play:

> The collective agreements were concluded between a regulated monopoly, which passes costs on to consumers, not a competitive enterprise, and two unions which account for approximately 90 per cent of the employees and amount to a near, second monopoly, based on terms inherited from Ontario Hydro and in face of the reality that running a nuclear operation without the employees would be extremely difficult. [para. 54]

36 Justice Aitken dissented, finding that,

> to the extent that [nuclear compensation] costs were predetermined, in the sense that they were locked in as a result of collective agreements entered prior to the date of the application and the test period, OPG only had to prove their prudence or reasonableness based on the circumstances that were known or that reasonably could have been anticipated at the time the decision to enter those collective agreements was made. [para. 83]

She would have held that the Board's failure to undertake a separate and explicit prudence review for the committed portion of nuclear compensation costs, coupled with its consideration of hindsight factors in assessing the reasonableness of these costs, rendered the Board Decision unreasonable.

C. Ontario Court of Appeal: 2013 ONCA 359, 116 O.R. (3d) 793 (Ont. C.A.)

37 The Ontario Court of Appeal reversed the Divisional Court's decision and remitted the case to the Board. The court drew a distinction between forecast costs and committed costs, with committed costs being those that the utility "is committed to pay in [the test period]" and that "cannot be managed or reduced by the utility in that time frame, usually because of contractual obligations" (para. 29). Although costs may not require actual payment until the future, as in this case, costs that have been "contractually incurred to be paid over the time frame are nonetheless committed even though they have not yet been paid" (para. 29). When reviewing such costs, the court held that the Board must undertake a prudence review as described in *Enbridge Gas Distribution Inc. v. Ontario (Energy Board)* (2006), 210 O.A.C. 4 (Ont. C.A.) (paras. 15-16). By failing to follow this jurisprudence and by requiring that OPG "manage costs that, by law, it cannot manage", the Board acted unreasonably (para. 37).

IV. Issues

38 The Board raises two issues on appeal:

1. What is the appropriate standard of review?

2. Was the Board's decision to disallow $145 million of OPG's revenue requirement reasonable?

39 Before this Court, OPG has argued that the Board stepped beyond the appropriate role of a tribunal in an appeal from its own decision, which raises the following additional issue:

3. Did the Board act impermissibly in pursuing its appeal in this case?

V. Analysis

40 It is logical to begin by considering the appropriateness of the Board's participation in the appeal. I will next consider the appropriate standard of review, and then the merits issue of whether the Board's decision in this case was reasonable.

A. The Appropriate Role of the Board in This Appeal

(1) Tribunal Standing

41 In *Northwestern Utilities Ltd., Re* (1978), [1979] 1 S.C.R. 684 (S.C.C.) ("*Northwestern Utilities*"), per Estey J., this Court first discussed how an administrative decision-maker's participation in the appeal or review of its own decisions may give rise to concerns over tribunal impartiality. Estey J. noted that "active and even aggressive participation can have no other effect than to discredit the impartiality of an administrative tribunal either in the case where the matter is referred back to it, or in future proceedings involving similar interests and issues or the same parties" (p. 709). He further observed that tribunals already receive an opportunity to make their views clear in their original decisions: "... it abuses one's notion of propriety to countenance its participation as a full-fledged litigant in this Court" (p. 709).

42 The Court in *Northwestern Utilities* ultimately held that the Alberta Public Utilities Board — which, like the Ontario Energy Board, had a statutory right to be heard on judicial appeal (see *Ontario Energy Board Act, 1998*, s. 33(3)) — was limited in the scope of the submissions it could make. Specifically, Estey J. observed that

> [i]t has been the policy in this Court to limit the role of an administrative tribunal whose decision is at issue before the Court, even where the right to appear is given by statute, to an explanatory role with reference to the record before the Board and to the making of representations relating to jurisdiction. [p. 709]

43 This Court further considered the issue of agency standing in *C.A.I.M.A.W., Local 14 v. Canadian Kenworth Co.*, [1989] 2 S.C.R. 983 (S.C.C.) [hereinafter Paccar], which involved judicial review of a British Columbia Labour Relations Board decision. Though a majority of the judges hearing the case did not endorse a particular approach to the issue, La Forest J., Dickson C.J. concurring, accepted that a tribunal had standing to explain the record and advance its view of the appropriate standard of review and, additionally, to argue that its decision was reasonable.

44 This finding was supported by the need to make sure the Court's decision on review of the tribunal's decision was fully informed. La Forest J. cited *B.C.G.E.U. v. British Columbia (Industrial Relations Council)* (1988), 26 B.C.L.R. (2d) 145 (B.C. C.A.), at p. 153, for the proposition that the tribunal is the party best equipped to draw the Court's attention to

> those considerations, rooted in the specialized jurisdiction or expertise of the tribunal, which may render reasonable what would otherwise appear unreasonable to someone not versed in the intricacies of the specialized area.
>
> (*Paccar*, at p. 1016)

La Forest J. found, however, that the tribunal could not go so far as to argue that its decision was correct (p. 1017). Though La Forest J. did not command a majority, L'Heureux-Dubé J. also commented on tribunal standing in her dissent, and agreed with the substance of La Forest J.'s analysis (p. 1026).

45 Trial and appellate courts have struggled to reconcile this Court's statements in *Northwestern Utilities* and *Paccar*. Indeed, while this Court has never expressly overturned *Northwestern Utilities*, on some occasions, it has permitted tribunals to participate as full parties without comment: see, e.g., *British Columbia (Securities Commission) v. McLean*,

2013 SCC 67, [2013] 3 S.C.R. 895 (S.C.C.); *I.B.E.W., Local 894 v. Ellis-Don Ltd.*, 2001 SCC 4, [2001] 1 S.C.R. 221 (S.C.C.); *Québec (Commission des affaires sociales) c. Tremblay*, [1992] 1 S.C.R. 952 (S.C.C.); see also *Children's Lawyer for Ontario v. Goodis* (2005), 75 O.R. (3d) 309 (Ont. C.A.) ("*Goodis*"), at para. 24.

46 A number of appellate decisions have grappled with this issue and "for the most part now display a more relaxed attitude in allowing tribunals to participate in judicial review proceedings or statutory appeals in which their decisions were subject to attack": D. Mullan, "Administrative Law and Energy Regulation", in Kaiser and Heggie, 35, at p. 51. A review of three appellate decisions suffices to establish the rationale behind this shift.

47 In *Goodis*, the Children's Lawyer urged the court to refuse or limit the standing of the Information and Privacy Commissioner, whose decision was under review. The Ontario Court of Appeal declined to apply any formal, fixed rule that would limit the tribunal to certain categories of submissions and instead adopted a contextual, discretionary approach: *Goodis*, at paras. 32-34. The court found no principled basis for the categorical approach, and observed that such an approach may lead to undesirable consequences:

> For example, a categorical rule denying standing if the attack asserts a denial of natural justice could deprive the court of vital submissions if the attack is based on alleged deficiencies in the structure or operation of the tribunal, since these are submissions that the tribunal is uniquely placed to make. Similarly, a rule that would permit a tribunal standing to defend its decision against the standard of reasonableness but not against one of correctness, would allow unnecessary and prevent useful argument. Because the best argument that a decision is reasonable may be that it is correct, a rule based on this distinction seems tenuously founded at best as Robertson J.A. said in *United Brotherhood of Carpenters and Joiners of America, Local 1386 v. Bransen Construction Ltd.*, [2002] N.B.J. No. 114, 249 N.B.R. (2d) 93 (C.A.); at para. 32.
>
> (*Goodis*, at para. 34)

48 The court held that *Northwestern Utilities* and *Paccar* should be read as the source of "fundamental considerations" that should guide the court's exercise of discretion in the context of the case: *Goodis*, at para. 35. The two most important considerations, drawn from those cases, were the "importance of having a fully informed adjudication of the issues before the court" (para. 37), and "the importance of maintaining tribunal impartiality": para. 38. The court should limit tribunal participation if it will undermine future confidence in its objectivity. The court identified a list of factors, discussed further below, that may aid in determining whether and to what extent the tribunal should be permitted to make submissions: paras. 36-38.

49 In *Quadrini v. Canada (Revenue Agency)*, 2010 FCA 246, [2012] 2 F.C.R. 3 (F.C.A.), Stratas J.A. identified two common law restrictions that, in his view, restricted the scope of a tribunal's participation on appeal from its own decision: finality and impartiality. Finality, the principle whereby a tribunal may not speak on a matter again once it has decided upon it and provided reasons for its decision, is discussed in greater detail below, as it is more directly related to concerns surrounding "bootstrapping" rather than agency standing itself.

50 The principle of impartiality is implicated by tribunal argument on appeal, because decisions may in some cases be remitted to the tribunal for further consideration. Stratas J.A. found that "[s]ubmissions by the tribunal in a judicial review proceeding that descend too far, too intensely, or too aggressively into the merits of the matter before the tribunal may disable the tribunal from conducting an impartial redetermination of the merits later": *Quadrini*, at para. 16. However, he ultimately found that these principles did not mandate "hard and fast rules", and endorsed the discretionary approach set out by the Ontario Court of Appeal in *Goodis*: *Quadrini*, at paras. 19-20.

51 A third example of recent judicial consideration of this issue may be found in *Leon's Furniture Ltd. v. Alberta (Information & Privacy Commissioner)*, 2011 ABCA 94, 502 A.R. 110 (Alta. C.A.). In this case, Leon's Furniture challenged the Commissioner's standing to make submissions on the merits of the appeal (para. 16). The Alberta Court of Appeal, too, adopted the position that the law should respond to the fundamental concerns raised in *Northwestern*

Utilities but should nonetheless approach the question of tribunal standing with discretion, to be exercised in view of relevant contextual considerations: paras. 28-29.

52 The considerations set forth by this Court in *Northwestern Utilities* reflect fundamental concerns with regard to tribunal participation on appeal from the tribunal's own decision. However, these concerns should not be read to establish a categorical ban on tribunal participation on appeal. A discretionary approach, as discussed by the courts in *Goodis*, *Leon's Furniture*, and *Quadrini*, provides the best means of ensuring that the principles of finality and impartiality are respected without sacrificing the ability of reviewing courts to hear useful and important information and analysis: see N. Semple, "The Case for Tribunal Standing in Canada" (2007), 20 *C.J.A.L.P.* 305; L. A. Jacobs and T. S. Kuttner, "Discovering What Tribunals Do: Tribunal Standing Before the Courts" (2002), 81 *Can. Bar Rev.* 616; F. A. V. Falzon, "Tribunal Standing on Judicial Review" (2008), 21 *C.J.A.L.P.* 21.

53 Several considerations argue in favour of a discretionary approach. Notably, because of their expertise and familiarity with the relevant administrative scheme, tribunals may in many cases be well positioned to help the reviewing court reach a just outcome. For example, a tribunal may be able to explain how one interpretation of a statutory provision might impact other provisions within the regulatory scheme, or to the factual and legal realities of the specialized field in which they work. Submissions of this type may be harder for other parties to present.

54 Some cases may arise in which there is simply no other party to stand in opposition to the party challenging the tribunal decision. Our judicial review processes are designed to function best when both sides of a dispute are argued vigorously before the reviewing court. In a situation where no other well-informed party stands opposed, the presence of a tribunal as an adversarial party may help the court ensure it has heard the best of both sides of a dispute.

55 Canadian tribunals occupy many different roles in the various contexts in which they operate. This variation means that concerns regarding tribunal partiality may be more or less salient depending on the case at issue and the tribunal's structure and statutory mandate. As such, statutory provisions addressing the structure, processes and role of the particular tribunal are key aspects of the analysis.

56 The mandate of the Board, and similarly situated regulatory tribunals, sets them apart from those tribunals whose function it is to adjudicate individual conflicts between two or more parties. For tribunals tasked with this latter responsibility, "the importance of fairness, real and perceived, weighs more heavily" against tribunal standing: *Henthorne v. British Columbia Ferry Services Inc.*, 2011 BCCA 476, 344 D.L.R. (4th) 292 (B.C. C.A.), at para. 42.

57 I am thus of the opinion that tribunal standing is a matter to be determined by the court conducting the first-instance review in accordance with the principled exercise of that court's discretion. In exercising its discretion, the court is required to balance the need for fully informed adjudication against the importance of maintaining tribunal impartiality.

58 In this case, as an initial matter, the *Ontario Energy Board Act, 1998* expressly provides that "[t]he Board is entitled to be heard by counsel upon the argument of an appeal" to the Divisional Court: s. 33(3). This provision neither expressly grants the Board standing to argue the merits of the decision on appeal, nor does it expressly limit the Board to jurisdictional or standard-of-review arguments as was the case for the relevant statutory provision in *Quadrini*: see para. 2.

59 In accordance with the foregoing discussion of tribunal standing, where the statute does not clearly resolve the issue, the reviewing court must rely on its discretion to define the tribunal's role on appeal. While not exhaustive, I would find the following factors, identified by the courts and academic commentators cited above, are relevant in informing the court's exercise of this discretion:

(1) If an appeal or review were to be otherwise unopposed, a reviewing court may benefit by exercising its discretion to grant tribunal standing.

> (2) If there are other parties available to oppose an appeal or review, and those parties have the necessary knowledge and expertise to fully make and respond to arguments on appeal or review, tribunal standing may be less important in ensuring just outcomes.
>
> (3) Whether the tribunal adjudicates individual conflicts between two adversarial parties, or whether it instead serves a policy-making, regulatory or investigative role, or acts on behalf of the public interest, bears on the degree to which impartiality concerns are raised. Such concerns may weigh more heavily where the tribunal served an adjudicatory function in the proceeding that is the subject of the appeal, while a proceeding in which the tribunal adopts a more regulatory role may not raise such concerns.

60 Consideration of these factors in the context of this case leads me to conclude that it was not improper for the Board to participate in arguing in favour of the reasonableness of its decision on appeal. First, the Board was the only respondent in the initial review of its decision. Thus, it had no alternative but to step in if the decision was to be defended on the merits. Unlike some other provinces, Ontario has no designated utility consumer advocate, which left the Board — tasked by statute with acting to safeguard the public interest — with few alternatives but to participate as a party.

61 Second, the Board is tasked with regulating the activities of utilities, including those in the electricity market. Its regulatory mandate is broad. Among its many roles: it licenses market participants, approves the development of new transmission and distribution facilities, and authorizes rates to be charged to consumers. In this case, the Board was exercising a regulatory role by setting just and reasonable payment amounts to a utility. This is unlike situations in which a tribunal may adjudicate disputes between two parties, in which case the interests of impartiality may weigh more heavily against full party standing.

62 The nature of utilities regulation further argues in favour of full party status for the Board here, as concerns about the appearance of partiality are muted in this context. As noted by Doherty J.A., "[l]ike all regulated bodies, I am sure Enbridge wins some and loses some before the [Board]. I am confident that Enbridge fully understands the role of the regulator and appreciates that each application is decided on its own merits by the [Board]": *Enbridge*, at para. 28. Accordingly, I do not find that the Board's participation in the instant appeal was improper. It remains to consider whether the content of the Board's arguments was appropriate.

(2) Bootstrapping

63 The issue of tribunal "bootstrapping" is closely related to the question of when it is proper for a tribunal to act as a party on appeal or judicial review of its decision. The standing issue concerns what types of argument a tribunal may make, i.e. jurisdictional or merits arguments, while the bootstrapping issue concerns the content of those arguments.

64 As the term has been understood by the courts who have considered it in the context of tribunal standing, a tribunal engages in bootstrapping where it seeks to supplement what would otherwise be a deficient decision with new arguments on appeal: see, e.g., *Bransen Construction Ltd. v. C.J.A., Local 1386*, 2002 NBCA 27, 249 N.B.R. (2d) 93 (N.B. C.A.). Put differently, it has been stated that a tribunal may not "defen[d] its decision on a ground that it did not rely on in the decision under review": *Goodis*, at para. 42.

65 The principle of finality dictates that once a tribunal has decided the issues before it and provided reasons for its decision, "absent a power to vary its decision or rehear the matter, it has spoken finally on the matter and its job is done": *Quadrini* , at para. 16, citing *Chandler v. Assn. of Architects (Alberta)*, [1989] 2 S.C.R. 848 (S.C.C.). Under this principle, the court found that tribunals could not use judicial review as a chance to "amend, vary, qualify or supplement its reasons": *Quadrini*, at para. 16. In *Leon's Furniture*, Slatter J.A. reasoned that a tribunal could "offer interpretations of its reasons or conclusion, [but] cannot attempt to reconfigure those reasons, add arguments not previously given, or make submissions about matters of fact not already engaged by the record": para. 29.

66 By contrast, in *Goodis*, Goudge J.A. found on behalf of a unanimous court that while the Commissioner had relied on an argument not expressly set out in her original decision, this argument was available for the Commissioner to make on appeal. Though he recognized that "[t]he importance of reasoned decision making may be undermined if, when attacked in court, a tribunal can simply offer different, better, or even contrary reasons to support its decision" (para. 42), Goudge J.A. ultimately found that the Commissioner was permitted to raise a new argument on judicial review. The new argument presented was "not inconsistent with the reason offered in the decision. Indeed it could be said to be implicit in it": para. 55. "It was therefore proper for the Commissioner to be permitted to raise this argument before the Divisional Court and equally proper for the court to decide on that basis": para. 58.

67 There is merit in both positions on the issue of bootstrapping. On the one hand, a permissive stance toward new arguments by tribunals on appeal serves the interests of justice insofar as it ensures that a reviewing court is presented with the strongest arguments in favour of both sides: Semple, at p. 315. This remains true even if those arguments were not included in the tribunal's original reasons. On the other hand, to permit bootstrapping may undermine the importance of reasoned, well-written original decisions. There is also the possibility that a tribunal, surprising the parties with new arguments in an appeal or judicial review after its initial decision, may lead the parties to see the process as unfair. This may be particularly true where a tribunal is tasked with adjudicating matters between two private litigants, as the introduction of new arguments by the tribunal on appeal may give the appearance that it is "ganging up" on one party. As discussed, however, it may be less appropriate in general for a tribunal sitting in this type of role to participate as a party on appeal.

68 I am not persuaded that the introduction of arguments by a tribunal on appeal that interpret or were implicit but not expressly articulated in its original decision offends the principle of finality. Similarly, it does not offend finality to permit a tribunal to explain its established policies and practices to the reviewing court, even if those were not described in the reasons under review. Tribunals need not repeat explanations of such practices in every decision merely to guard against charges of bootstrapping should they be called upon to explain them on appeal or review. A tribunal may also respond to arguments raised by a counterparty. A tribunal raising arguments of these types on review of its decision does so in order to uphold the initial decision; it is not reopening the case and issuing a new or modified decision. The result of the original decision remains the same even if a tribunal seeks to uphold that effect by providing an interpretation of it or on grounds implicit in the original decision.

69 I am not, however, of the opinion that tribunals should have the unfettered ability to raise entirely new arguments on judicial review. To do so may raise concerns about the appearance of unfairness and the need for tribunal decisions to be well reasoned in the first instance. I would find that the proper balancing of these interests against the reviewing courts' interests in hearing the strongest possible arguments in favour of each side of a dispute is struck when tribunals do retain the ability to offer interpretations of their reasons or conclusions and to make arguments implicit within their original reasons: see *Leon's Furniture*, at para. 29; *Goodis*, at para. 55.

70 In this case, I do not find that the Board impermissibly stepped beyond the bounds of its original decision in its arguments before this Court. In its reply factum, the Board pointed out — correctly, in my view — that its submissions before this Court simply highlight what is apparent on the face of the record, or respond to arguments raised by the respondents.

71 I would, however, urge the Board, and tribunal parties in general, to be cognizant of the tone they adopt on review of their decisions. As Goudge J.A. noted in *Goodis*:

> ... if an administrative tribunal seeks to make submissions on a judicial review of its decision, it [should] pay careful attention to the tone with which it does so. Although this is not a discrete basis upon which its standing might be limited, there is no doubt that the tone of the proposed submissions provides the background for the determination of that issue. A tribunal that seeks to resist a judicial review application will be of assistance to the court to the

> degree its submissions are characterized by the helpful elucidation of the issues, informed by its specialized position, rather than by the aggressive partisanship of an adversary. [para. 61]

72 In this case, the Board generally acted in such a way as to present helpful argument in an adversarial but respectful manner. However, I would sound a note of caution about the Board's assertion that the imposition of the prudent investment test "would in all likelihood not change the result" if the decision were remitted for reconsideration (A.F., at para. 99). This type of statement may, if carried too far, raise concerns about the principle of impartiality such that a court would be justified in exercising its discretion to limit tribunal standing so as to safeguard this principle.

B. Standard of Review

73 The parties do not dispute that reasonableness is the appropriate standard of review for the Board's actions in applying its expertise to set rates and approve payment amounts under the *Ontario Energy Board Act, 1998*. I agree. In addition, to the extent that the resolution of this appeal turns on the interpretation of the *Ontario Energy Board Act*, *1998*, the Board's home statute, a standard of reasonableness presumptively applies: *New Brunswick (Board of Management) v. Dunsmuir*, 2008 SCC 9, [2008] 1 S.C.R. 190 (S.C.C.), at para. 54; *A.T.A. v. Alberta (Information & Privacy Commissioner)*, 2011 SCC 61, [2011] 3 S.C.R. 654 (S.C.C.), at para. 30; *Commissioner of Competition v. CCS Corp.*, 2015 SCC 3, [2015] 1 S.C.R. 161 (S.C.C.), at para. 35. Nothing in this case suggests the presumption should be rebutted.

74 This appeal involves two distinct uses of the term "reasonable". One concerns the standard of review: on appeal, this Court is charged with evaluating the "justification, transparency and intelligibility" of the Board's reasoning, and "whether the decision falls within a range of possible, acceptable outcomes which are defensible in respect of the facts and law" (*Dunsmuir*, at para. 47). The other is statutory: the Board's rate-setting powers are to be used to ensure that, in its view, a just and reasonable balance is struck between utility and consumer interests. These reasons will attempt to keep the two uses of the term distinct.

C. Choice of Methodology Under the Ontario Energy Board Act, 1998

75 The question of whether the Board's decision to disallow recovery of certain costs was reasonable turns on how that decision relates to the Board's statutory and regulatory powers to approve payments to utilities and to have these payments reflected in the rates paid by consumers. The Board's general rate- and payment-setting powers are described above under the "Regulatory Framework" heading.

76 The just-and-reasonable approach to recovery of the cost of services provided by a utility captures the essential balance at the heart of utilities regulation: to encourage investment in a robust utility infrastructure and to protect consumer interests, utilities must be allowed, over the long run, to earn their cost of capital, no more, no less.

77 The *Ontario Energy Board Act, 1998* does not, however, either in s. 78.1 or elsewhere, prescribe the methodology the Board must use to weigh utility and consumer interests when deciding what constitutes just and reasonable payment amounts to the utility. Indeed, s. 6(1) of O. Reg. 53/05 expressly permits the Board, subject to certain exceptions set out in s. 6(2), to "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".

78 As a contrasting example, s. 6(2) 4.1 of O. Reg. 53/05 establishes a specific methodology for use when the Board reviews "costs incurred and firm financial commitments made in the course of planning and preparation for the development of proposed new nuclear generation facilities". When reviewing such costs, the Board must be satisfied that "the costs were *prudently incurred*" and that "the financial commitments were *prudently made*": s. 6(2)4.1. The provision thus establishes a specific context in which the Board's analysis is focused on the prudence of the decision to incur or commit to certain costs. The absence of such language in the more general s. 6(1) provides further reason to read the regulation as providing broad methodological discretion to the Board in making orders for payment amounts where the specific provisions of s. 6(2) do not apply.

79 Regarding whether a presumption of prudence must be applied to OPG's decisions to incur costs, neither the *Ontario Energy Board Act, 1998* nor O. Reg. 53/05 expressly establishes such a presumption. Indeed, the *Ontario Energy Board Act, 1998* places the burden on the applicant utility to establish that payment amounts approved by the Board are just and reasonable: s. 78.1(6) and (7). It would thus seem inconsistent with the statutory scheme to presume that utility decisions to incur costs were prudent.

80 Justice Abella concludes that the Board's review of OPG's costs should have consisted of "an after-the-fact prudence review, with a rebuttable presumption that the utility's expenditures were reasonable": para. 150. Such an approach is contrary to the statutory scheme. While the Board has considerable methodological discretion, it does not have the freedom to displace the burden of proof established by s. 78.1(6) of the *Ontario Energy Board Act, 1998* "... the burden of proof is on the applicant in an application made under this section". Of course, this does not imply that the applicant must systematically prove that every single cost is just and reasonable. The Board has broad discretion to determine the methods it may use to examine costs — it just cannot shift the burden of proof contrary to the statutory scheme.

81 In judicially reviewing a decision of the Board to allow or disallow payments to a utility, the court's role is to assess whether the Board reasonably determined that a certain payment amount was "just and reasonable" for both the utility and the consumers. Such an approach is consistent with this Court's rate-setting jurisprudence in other regulatory domains in which the regulator is given methodological discretion, where it has been observed that "[t]he obligation to act is a question of law, but the choice of the method to be adopted is a question of discretion with which, under the statute, no Court of law may interfere": *Bell Canada v. Canadian Radio-Television & Telecommunications Commission*, 2009 SCC 40, [2009] 2 S.C.R. 764 (S.C.C.), at para. 40 (concerning telecommunication rate-setting), quoting *General Increase in Freight Rates, Re* (1954), 76 C.R.T.C. 12 (S.C.C.), at p. 13 (concerning railway freight rates). Of course, today this statement must be understood to permit intervention by a court where the exercise of discretion rendered a decision unreasonable. Accordingly, it remains to determine whether the Board's analytical approach to disallowing the costs at issue in this case rendered the Board's decision unreasonable under the "just and reasonable" standard.

D. Characterization of Costs at Issue

82 Forecast costs are costs which the utility has not yet paid, and over which the utility still retains discretion as to whether the disbursement will be made. A disallowance of such costs presents a utility with a choice: it may change its plans and avoid the disallowed costs, or it may incur the costs regardless of the disallowance with the knowledge that the costs will ultimately be borne by the utility's shareholders rather than its ratepayers. By contrast, committed costs are those for which, if a regulatory board disallows recovery of the costs in approved payments, the utility and its shareholders will have no choice but to bear the burden of those costs themselves. This result may occur because the utility has already spent the funds, or because the utility entered into a binding commitment or was subject to other legal obligations that leave it with no discretion as to whether to make the payment in the future.

83 There is disagreement between the parties as to how the costs disallowed by the Board in this matter should be characterized. The Board asserts that compensation costs for the test period are forecast insofar as they have not yet been disbursed, while OPG asserts that the costs should be characterized as committed, because OPG is under a contractual obligation to pay those amounts when they become due. This disagreement is important because a "no hind-sight" prudence review, which is discussed in detail below, has developed in the context of "committed" costs. Indeed, it makes no sense to apply such a test where a utility still retains discretion over whether the costs will ultimately be incurred; the decision to commit the utility to such costs has not yet been made. Accordingly, where the regulator has discretion over its methodological approach, understanding whether the costs at issue are "forecast" or "committed" may be helpful in reviewing the reasonableness of a regulator's choice of methodology.

84 In this case, at least some of the compensation costs that the Board found to be excessive were driven by collective agreements to which OPG had committed before the application at issue, and which established compensation costs that were, in aggregate, above the 75th percentile for comparable positions at other utilities. The collective agreements left

OPG with limited flexibility regarding overall compensation rates or staffing levels — OPG was required to abide by wage and staffing levels established by collective agreements, and retained flexibility only over terms outside the bounds of those agreements — and thus those portions of OPG's compensation rates and staffing levels that were dictated by the terms of the collective agreements were committed costs.

85 However, the Board found that OPG's compensation costs for the test period were not entirely driven by the collective agreements, and thus were not entirely committed, because OPG retained some flexibility to manage total staffing levels in light of projected attrition of a mature workforce. The Board Decision did not, however, include detailed forecasts regarding exactly how much of the $145 million in disallowed compensation costs could be recovered through natural reduction in employee numbers or other adjustments, and how much would necessarily be borne by the utility and its shareholder. Accordingly, the disallowed costs at issue must be understood as being at least partially committed. It is unreasonable to characterize them as entirely forecast in view of the constraints placed on OPG by the collective agreements.

86 Having established that the disallowed costs are at least partially committed, it is necessary to consider whether the Board acted reasonably in not applying a no-hindsight prudent investment test in assessing those costs. Accordingly, I now turn to the jurisprudential history and methodological details of the prudent investment test.

E. The Prudent Investment Test

87 In order to assess whether the Board's methodology was reasonable in this case, it is necessary to provide some background on the prudent investment test (sometimes referred to as "prudence review" or the "prudence test") in order to identify its origins, place it in context, and explore how it has been understood by utilities, regulators, and legislators.

(1) American Jurisprudence

88 American jurisprudence has played a significant role in the history of the prudent investment test in utilities regulation. In discussing this history, I would first reiterate this Court's observation that "[w]hile the American jurisprudence and texts in this area should be considered with caution given that Canada and the United States have very different political and constitutional-legal regimes, they do shed some light on the issue": *ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board)*, 2006 SCC 4, [2006] 1 S.C.R. 140 (S.C.C.), at para. 54.

89 The origins of the prudent investment test in the context of utilities regulation may be traced to Justice Brandeis of the Supreme Court of the United States, who wrote a concurring opinion in 1923 to observe that utilities should receive deference in seeking to recover "investments which, under ordinary circumstances, would be deemed reasonable": *State of Missouri ex rel. Southwestern Bell Telephone Co. v. Public Service Commission of Missouri*, 262 U.S. 276 (U.S. Mo. S.C. 1923), at p. 289, fn.1.

90 In the decades that followed, American utility regulators tasked with reviewing past-incurred utility costs generally employed one of two standards: the "used and useful" test or the "prudent investment" test (J. Kahn, "Keep *Hope* Alive: Updating the Prudent Investment Standard for Allocating Nuclear Plant Cancellation Costs" (2010), 22 *Fordham Envtl. L. Rev.* 43, at p. 49). These tests took different approaches to determining what costs could justly and reasonably be passed on to ratepayers. The used and useful test allowed utilities to earn returns only on those investments that were actually used and useful to the utility's operations, on the principle that ratepayers should not be compelled to pay for investments that do not benefit them.

91 By contrast, the prudent investment test followed Justice Brandeis's preferred approach by allowing for recovery of costs provided they were not imprudent based on what was known at the time the investment or expense was incurred: Kahn, at pp. 49-50. Though it may seem problematic from the perspective of consumer interests to adopt the prudent investment test — a test that allows for payments related to investments that may not be used or useful — it gives regulators a tool to soften the potentially harsh effects of the used and useful test, which may place onerous burdens on utilities. Disallowing recovery of the cost of failed investments that appeared reasonable at the time, for example,

may imperil the financial health of utilities, and may chill the incentive to make such investments in the first place. This effect may then have negative implications for consumers, whose long-run interests will be best served by a dynamically efficient and viable electricity industry. Thus, the prudent investment test may be employed by regulators to strike the appropriate balance between consumer and utility interests: see Kahn, at pp. 53-54.

92 The states differed in their approaches to setting the statutory foundation for utility regulation. Regulators in some states were free to apply the prudent investment test, while other states enacted statutory provisions disallowing compensation in respect of capital investments that were not "used and useful in service to the public": *Duquesne Light Co. v. Barasch*, 488 U.S. 299 (U.S. Sup. Ct. 1989), at p. 302. Notably, when asked in *Duquesne* to consider whether "just and reasonable" payments to utilities required, as a constitutional matter, that the prudent investment test be applied to past-incurred costs, the U.S. Supreme Court held that "[t]he designation of a single theory of ratemaking as a constitutional requirement would unnecessarily foreclose alternatives which could benefit both consumers and investors": p. 316.

93 American courts have also recognized that there may exist some contexts in which certain features of the prudent investment test may be less justifiable. For example, the Supreme Court of Utah considered whether a presumption of reasonableness was justified when reviewing costs passed to a utility by an unregulated affiliate entity, and concluded that it was not appropriate:

> ... we do not think an affiliate expense should carry a presumption of reasonableness. While the pressures of a competitive market might allow us to assume, in the absence of a showing to the contrary, that nonaffiliate expenses are reasonable, the same cannot be said of affiliate expenses not incurred in an arm's length transaction.

(*US West Communications Inc. v. Public Service Commission of Utah*, 901 P.2d 270 (U.S. Utah S.C. 1995), p. 274)

94 Treatment of the prudent investment test in American jurisprudence thus indicates that the test has been employed as a tool that may be useful in arriving at just and reasonable outcomes, rather than a mandatory feature of utilities regulation that must be applied regardless of whether there is statutory language to that effect.

(2) Canadian Jurisprudence

95 Following its emergence in American jurisprudence, several Canadian utility regulators and courts have also considered the role of prudence review and, in some cases, applied a form of the prudent investment test. I provide a review of some of these cases here not in an attempt to exhaustively catalogue all uses of the test, but rather to set out the way in which the test has been invoked in various contexts.

96 In *British Columbia Electric Railway v. British Columbia (Public Utilities Commission)*, [1960] S.C.R. 837 (S.C.C.), Martland J. observed that the statute at issue in that case directed that the regulator, in fixing rates,

> (a) ... shall consider all matters which it deems proper as affecting the rate: [and]
>
> (b) ... shall have due regard, among other things, to the protection of the public from rates that are excessive as being more than a fair and reasonable charge for services of the nature and quality furnished by the public utility; and to giving to the public utility a fair and reasonable return upon the appraised value of the property of the public utility used, or prudently and reasonably acquired, to enable the public utility to furnish the service. [p. 852]

(Quoting *Public Utilities Act*, R.S.B.C. 1948, s. 16(1)(*b*) (repealed S.B.C. 1973, c. 29, s. 187).)

The consequence of this statutory language, Martland J. held, was that the regulator, "when dealing with a rate case, has unlimited discretion as to the matters which it may consider as affecting the rate, but that it must, when actually setting the rate, meet the two requirements specifically mentioned in clause (*b*)": at p. 856. That is, the regulator, under this statute, must ensure that the public pays only fair and reasonable charges, and that the utility secures a fair and reasonable return upon its property used *or prudently and reasonably acquired*. This express statutory protection for the recovery of prudently made property acquisition costs thus provides an example of statutory language under which this Court found a non-discretionary obligation to provide a fair return to utilities for capital expenditures that were either used or prudently acquired.

97 In 2005, the Nova Scotia Utility and Review Board ("NSUARB") considered and adopted a definition of the prudent investment test articulated by the Illinois Commerce Commission:

> ... prudence is that standard of care which a reasonable person would be expected to exercise under the same circumstances encountered by utility management at the time decisions had to be made. ... Hindsight is not applied in assessing prudence. ... A utility's decision is prudent if it was within the range of decisions reasonable persons might have made. ... The prudence standard recognizes that reasonable persons can have honest differences of opinion without one or the other necessarily being imprudent.
>
> (*Nova Scotia Power Inc., Re*, 2005 NSUARB 27 (N.S. Utility & Review Bd.) ("*Nova Scotia Power 2005*"), at para. 84 (CanLII))

The NSUARB then wrote that "[f]ollowing a review of the cases, the Board finds that the definition of imprudence as set out by the Illinois Commerce Commission is a reasonable test to be applied in Nova Scotia": para. 90. The NSUARB then considered, among other things, whether the utility's recent fuel procurement strategy had been prudent, and found that it had not: para. 94. It did not, however, indicate that it believed itself to be compelled to apply the prudent investment test.

98 The NSUARB reaffirmed its endorsement of the prudent investment test in 2012: *Nova Scotia Power Inc., Re*, 2012 NSUARB 227 (N.S. Utility & Review Bd.) ("*Nova Scotia Power 2012*"), at paras. 143-46 (CanLII). In that case, the utility whose submissions were under review "confirmed that from its perspective this is the test the Board should apply": para. 146. The NSUARB then applied the prudence test in evaluating whether several of the utility's operational decisions were prudent, and found that some were not: para. 188.

99 In 2006, the Ontario Court of Appeal considered the meaning of the prudent investment test in *Enbridge*. This case is of particular interest for two reasons. First, the Ontario Court of Appeal endorsed in its reasons a specific formulation of the prudent investment test framework:

> • Decisions made by the utility's management should generally be presumed to be prudent unless challenged on reasonable grounds.
>
> • To be prudent, a decision must have been reasonable under the circumstances that were known or ought to have been known to the utility at the time the decision was made.
>
> • Hindsight should not be used in determining prudence, although consideration of the outcome of the decision may legitimately be used to overcome the presumption of prudence.
>
> • Prudence must be determined in a retrospective factual inquiry, in that the evidence must be concerned with the time the decision was made and must be based on facts about the elements that could or did enter into the decision at the time. [para. 10]

100 Second, the Court of Appeal in *Enbridge* made certain statements that suggest that the prudent investment test was a necessary approach to reviewing committed costs. Specifically, it noted that in deciding whether Enbridge's requested rate increase was just and reasonable,

> the [Board] was required to balance the competing interests of Enbridge and its consumers. That balancing process is achieved by the application of what is known in the utility rate regulation field as the "prudence" test. Enbridge was entitled to recover its costs by way of a rate increase only if those costs were "prudently" incurred. [para. 8]

The Court of Appeal also noted that the Board had applied the "proper test": para. 18. These statements tend to suggest that the Court of Appeal was of the opinion that prudence review is an inherent and necessary part of ensuring just and reasonable payments.

101 However, the question of whether the prudence test was a required feature of just-and-reasonable analysis in this context was not squarely before the Court of Appeal in *Enbridge*. Rather, the parties in that case "were in substantial agreement on the general approach the Board should take to reviewing the prudence of a utility's decision" (para. 10), and the question at issue was whether the Board had reasonably applied that agreed-upon approach. In this sense, *Enbridge* is similar to *Nova Scotia Power 2012*: both cases involved the application of prudence analysis in contexts where there was no dispute over whether an alternative methodology could reasonably have been applied.

(3) Conclusion Regarding the Prudent Investment Test

102 The prudent investment test, or prudence review, is a valid and widely accepted tool that regulators may use when assessing whether payments to a utility would be just and reasonable. While there exists different articulations of prudence review, *Enbridge* presents one express statement of how a regulatory board might structure its review to assess the prudence of utility expenditures at the time they were incurred or committed. A no-hindsight prudence review has most frequently been applied in the context of capital costs, but *Enbridge* and *Nova Scotia Power* (both *Nova Scotia Power 2005* and *Nova Scotia Power 2012*) provide examples of its application to decisions regarding operating costs as well. I see no reason in principle why a regulatory board should be barred from applying the prudence test to operating costs.

103 However, I do not find support in the statutory scheme or the relevant jurisprudence for the notion that the Board should be *required* as a matter of law, under the *Ontario Energy Board Act, 1998*, to apply the prudence test as outlined in *Enbridge* such that the mere decision not to apply it when considering committed costs would render its decision on payment amounts unreasonable. Nor is the creation of such an obligation by this Court justified. As discussed above, where a statute requires only that the regulator set "just and reasonable" payments, as the *Ontario Energy Board Act, 1998* does in Ontario, the regulator may make use of a variety of analytical tools in assessing the justness and reasonableness of a utility's proposed payment amounts. This is particularly so where, as here, the regulator has been given express discretion over the methodology to be used in setting payment amounts: O. Reg. 53/05, s. 6(1).

104 To summarize, it is not necessarily unreasonable, in light of the particular regulatory structure established by the *Ontario Energy Board Act, 1998*, for the Board to evaluate committed costs using a method other than a no-hindsight prudence review. As noted above, applying a presumption of prudence would have conflicted with the burden of proof in the *Ontario Energy Board Act, 1998* and would therefore not have been reasonable. The question of whether it was reasonable to assess a particular cost using hindsight should turn instead on the circumstances of that cost. I emphasize, however, that this decision should not be read to give regulators *carte blanche* to disallow a utility's committed costs at will. Prudence review of committed costs may in many cases be a sound way of ensuring that utilities are treated fairly and remain able to secure required levels of investment capital. As will be explained, particularly with regard to committed capital costs, prudence review will often provide a reasonable means of striking the balance of fairness between consumers and utilities.

105 This conclusion regarding the Board's ability to select its methodology rests on the particulars of the statutory scheme under which the Board operates. There exist other statutory schemes in which regulators are expressly required to compensate utilities for certain costs prudently incurred: see *British Columbia Electric Railway Co*. Under such a framework, the regulator's methodological discretion may be more constrained.

(4) Application to the Board's Decision

106 In this case, the Board disallowed a total of $145 million in compensation costs associated with OPG's nuclear operations, over two years. As discussed above, these costs are best understood as at least partly committed. In view of the nature of these particular costs and the circumstances in which they became committed, I do not find that the Board

acted unreasonably in not applying the prudent investment test in determining whether it would be just and reasonable to compensate OPG for these costs.

107 First, the costs at issue are operating costs, rather than capital costs. Capital costs, particularly those pertaining to areas such as capacity expansion or upgrades to existing facilities, often entail some amount of risk, and may not always be strictly necessary to the short-term ongoing production of the utility. Nevertheless, such costs may often be a wise investment in the utility's future health and viability. As such, prudence review, including a no-hindsight approach (with or without a presumption of prudence, depending on the applicable statutory context), may play a particularly important role in ensuring that utilities are not discouraged from making the optimal level of investment in the development of their facilities.

108 Operating costs, like those at issue here, are different in kind from capital costs. There is little danger in this case that a disallowance of these costs will have a chilling effect on OPG's willingness to incur operating costs in the future, because costs of the type disallowed here are an inescapable element of operating a utility. It is true that a decision such as the Board's in this case may have the effect of making OPG more hesitant about committing to relatively high compensation costs, but that was precisely the intended effect of the Board's decision.

109 Second, the costs at issue arise in the context of an ongoing, "repeat-player" relationship between OPG and its employees. Prudence review has its origins in the examination of decisions to pursue particular investments, such as a decision to invest in capacity expansion; these are often one-time decisions made in view of a particular set of circumstances known or assumed at the time the decision was made.

110 By contrast, OPG's committed compensation costs arise in the context of an ongoing relationship in which OPG will have to negotiate compensation costs with the same parties in the future. Such a context supports the reasonableness of a regulator's decision to weigh all evidence it finds relevant in striking a just and reasonable balance between the utility and consumers, rather than confining itself to a no-hindsight approach. Prudence review is simply less relevant when the Board's focus is not solely on compensating for past commitments, but on regulating costs to be incurred in the future as well. As will be discussed further, the Board's ultimate disallowance was not targeted exclusively at committed costs, but rather was made with respect to the total compensation costs it evaluated in aggregate. Though the Board acknowledged that OPG may not have had the discretion to reduce spending by the entire amount of the disallowance, the disallowance was animated by the Board's efforts to get OPG's ongoing compensation costs under control.

111 Having already given OPG a warning that the Board found its operational costs to be of concern (see Board 2008-2009 Decision, at pp. 28-32), it was not unreasonable for the Board to be more forceful in considering compensation costs to ensure effective regulation of such costs going forward. The Board's statement that its disallowance was intended "to send a clear signal that OPG must take responsibility for improving its performance" (Board Decision, at p. 86) shows that it had the ongoing effects of its disallowance squarely in mind in issuing its decision in this case.

112 The reasonableness of the Board's decision to disallow $145 million in compensation costs is supported by the Board's recognition of the fact that OPG was bound to a certain extent by the collective agreements in making staffing decisions and setting compensation rates, and its consideration of this factor in setting the total disallowance: Board Decision, at p. 87. The Board's methodological flexibility ensures that its decision need not be "all or nothing". Where appropriate, to the extent that the utility was unable to reduce its costs, the total burden of such costs may be moderated or shared as between the utility's shareholders and the consumers. The Board's moderation in this case shows that, in choosing to disallow costs without applying a formal no-hindsight prudence review, it remained mindful of the need to ensure that any disallowance was not unfair to OPG and certainly did not impair the viability of the utility.

113 Justice Abella, in her dissent, acknowledges that the Board has the power under prudence review to disallow committed costs in at least some circumstances: para. 152. However, she speculates that any such disallowance could "imperil the assurance of reliable electricity service": para. 156. A large or indiscriminate disallowance might create such

peril, but it is also possible for the Board to do as it did here, and temper its disallowance to recognize the realities facing the utility.

114 There is no dispute that collective agreements are "immutable" between employees and the utility. However, if the legislature had intended for costs under collective agreements to also be inevitably imposed on consumers, it would not have seen fit to grant the Board oversight of utility compensation costs. The existence both of collective bargaining for utility employees and of the Board's power to fix payment amounts covering compensation costs indicates neither regime can trump the other. The Board cannot interfere with the collective agreement by ordering that a utility break its obligations thereunder, but nor can the collective agreement supersede the Board's duty to ensure a just and reasonable balance between utility and consumer interests.

115 Justice Abella says that the Board's review of committed costs using hindsight evidence appears to contradict statements made earlier in its decision. The Board wrote that it would use all relevant evidence in assessing forecast costs but that it would limit itself to a no-hindsight approach in reviewing costs that OPG could not "take action to reduce": Board Decision, at p. 19. In my view, these statements can be read as setting out a reasonable approach for analyzing costs that could reliably be fit into forecast or committed categories. However, not all costs are amenable to such clean categorization by the Board in assessing payment amounts for a test period.

116 With regard to the compensation costs at issue here, the Board declined to split the total cost disallowance into forecast and committed components in conducting its analysis. As Hoy J. observed, "[g]iven the complexity of OPG's business, and respecting its management's autonomy, [the Board] did not try to quantify precisely the amount by which OPG could reduce its forecast compensation costs within the framework of the existing collective bargaining agreements": Div. Ct. reasons, at para. 53. That is, the Board did not split all compensation costs into either "forecast" or "committed", but analyzed the disallowance of compensation costs as a mix of forecast and committed expenditures over which management retained some, but not total, control.

117 It was not unreasonable for the Board to proceed on the basis that predicting staff attrition rates is an inherently uncertain exercise, and that it is not equipped to micromanage business decisions within the purview of OPG management. These considerations mean that any attempt to predict the exact degree to which OPG would be able to reduce compensation costs (in other words, what share of the costs were forecast) would be fraught with uncertainty. Accordingly, it was not unreasonable for the Board to adopt a mixed approach that did not rely on quantifying the exact share of compensation costs that fell into the forecast and committed categories. Such an approach is not inconsistent with the Board's discussion at pp. 18-19, but rather represents an exercise of the Board's methodological discretion in addressing a challenging issue where these costs did not fit easily into the categories discussed in that passage.

118 Justice Abella emphasizes throughout her reasons that the costs established by the collective agreements were not adjustable. I do not dispute this point. However, to the extent that she relies on the observation that the collective agreements "made it *illegal* for the utility to alter the compensation and staffing levels" of the unionized workforce (para. 149 (emphasis in original)), one might conclude that the Board was in some way trying to interfere with OPG's obligations under its collective agreements. It is important not to lose sight of the fact that the Board decision in no way purports to force OPG to break its contractual commitments to unionized employees.

119 Finally, her observation that the Canadian Nuclear Safety Commission ("CNSC") "has ... imposed staffing levels on Ontario Power Generation to ensure safe and reliable operation of its nuclear stations" (para. 127) is irrelevant to the issues raised in this case. While the regime put in place by the CNSC surely imposes operational and staffing restraints on nuclear utilities (see OPG record, at pp. 43-46), there is nothing in the Board's reasons, and no argument presented before this Court, suggesting that the Board's disallowance will result in a violation of the provisions of the *Nuclear Safety and Control Act*, S.C. 1997, c. 9.

120 I have noted above that it is essential for a utility to earn its cost of capital in the long run. The Board's disallowance may have adversely impacted OPG's ability to earn its cost of capital in the short run. Nevertheless, the disallowance

was intended "to send a clear signal that OPG must take responsibility for improving its performance" (Board Decision, at p. 86). Such a signal may, in the short run, provide the necessary impetus for OPG to bring its compensation costs in line with what, in the Board's opinion, consumers should justly expect to pay for an efficiently provided service. Sending such a signal is consistent with the Board's market proxy role and its objectives under s. 1 of the *Ontario Energy Board Act, 1998*.

VI. Conclusion

121 I do not find that the Board acted improperly in pursuing this matter on appeal; nor do I find that it acted unreasonably in disallowing the compensation costs at issue. Accordingly, I would allow the appeal, set aside the decision of the Court of Appeal, and reinstate the decision of the Board.

***Abella J.* (dissenting):**

122 The Ontario Energy Board was established in 1960 to set rates for the sale and storage of natural gas and to approve pipeline construction projects. Over time, its powers and responsibilities evolved. In 1973, the Board became responsible for reviewing and reporting to the Minister of Energy on electricity rates. During this period, Ontario's electricity market was lightly regulated, dominated by the government-owned Ontario Hydro, which owned power generation assets responsible for about 90 per cent of electricity production in the province: Ron W. Clark, Scott A. Stoll and Fred D. Cass, *Ontario Energy Law: Electricity* (2012), at p. 134; *2011 Annual Report* of the Office of the Auditor General of Ontario, at pp. 5 and 67.

123 A series of legislative measures in the late 1990s were adopted to transform the electricity industry into a market-based one driven by competition. Ontario Hydro was unbundled into five entities. One of them was Ontario Power Generation Inc., which was given responsibility for controlling the power generation assets of the former Ontario Hydro. It was set up as a commercial corporation with one shareholder — the Province of Ontario: Clark, Stoll and Cass, at pp. 5-7 and 134.

124 As of April 1, 2008, the Board was given the authority by statute to set payments for the electricity generated by a prescribed list of assets held by Ontario Power Generation: *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Sch. B., s. 78.1(2); O. Reg. 53/05, *Payments Under Section 78.1 of the Act*, s. 3. Under the legislative scheme, Ontario Power Generation is required to apply to the Board for the approval of "just and reasonable" payment amounts: *Ontario Energy Board Act, 1998*, s. 78.1(5). The Board sets its own methodology to determine what "just and reasonable" payment amounts are, guided by the statutory objectives to maintain a "financially viable electricity industry" and to "protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service": O. Reg. 53/05, s. 6(1); *Ontario Energy Board Act, 1998*, ss. 1(1)1 and 1(1)2.

125 Ontario Power Generation remains the province's largest electricity generator. It was unionized by the Ontario Hydro Employees' Union (the predecessor to the Power Workers' Union) in the 1950s, and by the Society of Energy Professionals in 1992: Richard P. Chaykowski, *An Assessment of the Industrial Relations Context and Outcomes at OPG* (2013) (online), at s. 6.2. Today, Ontario Power Generation employs approximately 10,000 people in its regulated businesses, 90 per cent of whom are unionized. Two thirds of these unionized employees are represented by the Power Workers' Union, and the rest by the Society of Energy Professionals.

126 Both the Power Workers' Union and the Society of Energy Professionals had collective agreements with Ontario Hydro before Ontario Power Generation was established. As a successor company to Ontario Hydro, Ontario Power Generation inherited the full range of these labour relations obligations: Ontario *Labour Relations Act, 1995*, S.O. 1995, c. 1, Sch. A, s. 69. Ontario Power Generation's collective agreements with its unions prevent the utility from unilaterally reducing staffing or compensation levels.

127 The Canadian Nuclear Safety Commission, an independent federal government agency responsible for ensuring compliance with the *Nuclear Safety and Control Act*, S.C. 1997, c. 9, has also imposed staffing levels on Ontario Power Generation to ensure safe and reliable operation of its nuclear stations.

128 On May 26, 2010, Ontario Power Generation applied to the Board for a total revenue requirement of $6,909.6 million, including $2,783.9 million in compensation costs — wages, benefits, pension servicing, and annual incentives — to cover the period from January 1, 2011 to December 31, 2012: EB-2010-0008, at pp. 8, 49 and 80.

129 In its decision, the Board explained that it would use "two types of examination" to assess the utility's expenditures. When evaluating forecast costs — costs that the utility has estimated for a future period and which can still be reduced or avoided — the Board said that Ontario Power Generation bears the burden of showing that these costs are reasonable. On the other hand, when the Board would be evaluating costs for which "[t]here is no opportunity for the company to take action to reduce", otherwise known as committed costs, it said that it would undertake "an after-the-fact prudence review ... conducted in the manner which includes a presumption of prudence", that is, a presumption that the utility's expenditures are reasonable: p. 19.

130 The Board made no distinction between those compensation costs that were reducible and those that were not. Instead, it subjected all compensation costs to the kind of assessment it uses for reducible, forecast costs and disallowed $145 million because it concluded that the utility's compensation rates and staffing levels were too high.

131 On appeal, a majority of the Divisional Court upheld the Board's order. In dissenting reasons, Aitken J. concluded that the Board's decision was unreasonable because it did not apply the proper approach to the compensation costs which were, as a result of legally binding collective agreements, fixed and not adjustable. Instead, the Board "lumped" all compensation costs together and made no distinction between those that were the result of binding contractual obligations and those that were not. As she said:

> First, I consider any limitation on [Ontario Power Generation's] ability to manage nuclear compensation costs on a go-forward basis, due to binding collective agreements in effect prior to the application and the test period, to be costs previously incurred and subject to an after-the-fact, two-step, prudence review. Second, I conclude that, in considering [Ontario Power Generation's] nuclear compensation costs, as set out in its application, the [Board] in its analysis (though not necessarily in its final number) was required to differentiate between such earlier incurred liabilities and other aspects of the nuclear compensation cost package that were truly projected and not predetermined. Third, in my view, the [Board] was required to undergo a prudence review in regard to those aspects of the nuclear compensation package that arose under binding contracts entered prior to the application and the test period. In regard to the balance of factors making up the nuclear compensation package, the [Board] was free to determine, based on all available evidence, whether such factors were reasonable. Fourth, had a prudence review been undertaken, there was evidence upon which the [Board] could reasonably have decided that the presumption of prudence had been rebutted in regard to those cost factors mandated in the collective agreements. Unfortunately, I cannot find anywhere in the Decision of the [Board] where such an analysis was undertaken. The [Board] lumped all nuclear compensation costs together. It dealt with them as if they all emanated from the same type of factors and none reflected contractual obligations to which the [Ontario Power Generation] was bound due to a collective agreement entered prior to the application and the test period. Finally, I conclude that, when the [Board] was considering the reasonableness of the nuclear compensation package, it erred in considering evidence that came into existence after the date on which the collective agreements were entered when it assessed the reasonableness of the rates of pay and other binding provisions in the collective agreements. [para. 75]

132 The Court of Appeal unanimously agreed with Aitken J.'s conclusion, finding that "the compensation costs at issue before the [Board] were committed costs" which should therefore have been assessed using a presumption of prudence. As they both acknowledged, it was open to the Board to find that the presumption had been rebutted in connection

with the binding contractual obligations, but the Board acted unreasonably in failing to take the immutable nature of the fixed costs into consideration.

133 I agree. The compensation costs for approximately 90 per cent of Ontario Power Generation's regulated workforce were established through legally binding collective agreements which obligated the utility to pay fixed levels of compensation, regulated staffing levels, and provided unionized employees with employment security. Ontario Power Generation's compensation costs were therefore overwhelmingly predetermined and could not be adjusted by the utility during the relevant period. These are precisely the type of costs that the Board referred to in its decision as costs for which "[t]here is no opportunity for the company to take action to reduce" and which must be subjected to "a prudence review conducted in the manner which includes a presumption of prudence": p. 19.

134 In my respectful view, failing to acknowledge the legally binding, non-reducible nature of the cost commitments reflected in the collective agreements and apply the review the Board itself said should apply to such costs, rendered its decision unreasonable.

Analysis

135 Pursuant to s. 78.1(5) of the *Ontario Energy Board Act, 1998*, upon application from Ontario Power Generation, the Board is required to determine "just and reasonable" payment amounts to the utility. In the utility regulation context, the phrase "just and reasonable" reflects the aim of "navigating the straits" between overcharging a utility's customers and underpaying the utility for the public service it provides: *Verizon Communications Inc. v. Federal Communications Commission*, 535 U.S. 467 (U.S. Sup. Ct. 2002), at p. 481; see also *Edmonton (City) v. Northwestern Utilities Ltd.*, [1929] S.C.R. 186 (S.C.C.), at pp. 192-93.

136 The methodology adopted by the Board to determine "just and reasonable" payments to Ontario Power Generation draws in part on the regulatory concept of "prudence". Prudence is "a legal basis for adjudging the meeting of utilities' public interest obligations, specifically in regard to rate proceedings": Robert E. Burns et al., *The Prudent Investment Test in the 1980s*, report NRRI-84-16, The National Regulatory Research Institute, April 1985, at p. 20. The concept emerged in the early 20th century as a judicial response to the "mind-numbing complexity" of other approaches being used by regulators to determine "just and reasonable" amounts, and introduced a legal presumption that a regulated utility has acted reasonably: *Verizon Communications*, at p. 482. As Justice Brandeis famously explained in 1923:

> The term prudent investment is not used in a critical sense. There should not be excluded from the finding of the base, investments which, under ordinary circumstances, would be deemed reasonable. The term is applied for the purpose of excluding what might be found to be dishonest or obviously wasteful or imprudent expenditures. Every investment may be assumed to have been made in the exercise of reasonable judgment, unless the contrary is shown.
>
> [Emphasis added.]
>
> (*State of Missouri ex rel. Southwestern Bell Telephone Co. v. Public Service Commission of Missouri* (1923), 262 U.S. 276 (U.S. Mo. S.C. 1923), at p. 289, fn. 1, per Brandeis J., dissenting).

137 The presumption of prudence is the starting point for the type of examination the Board calls a "prudence review". In undertaking a prudence review, the Board applies a "well-established set of principles":

• Decisions made by the utility's management should generally be presumed to be prudent unless challenged on reasonable grounds.

• To be prudent, a decision must have been reasonable under the circumstances that were known or ought to have been known to the utility at the time the decision was made.

• Hindsight should not be used in determining prudence, although consideration of the outcome of the decision may legitimately be used to overcome the presumption of prudence.

• Prudence must be determined in a retrospective factual inquiry, in that the evidence must be concerned with the time the decision was made and must be based on facts about the elements that could or did enter into the decision at the time.

(*Enersource Hydro Mississauga Inc. (Re)*, 2012 LNONOEB 373 (QL), at para. 55, citing *Enbridge Gas Distribution (Re)*, 2002 LNONOEB 4 (QL), at para. 3.12.2).

138 This form of prudence review, including a presumption of prudence and a ban on hindsight, was endorsed by the Board and by the Ontario Court of Appeal as an appropriate method to determine "just and reasonable" rates in *Enbridge Gas Distribution Inc. (Re)*, at paras. 3.12.1 to 3.12.5, aff'd *Enbridge Gas Distribution Inc. v. Ontario (Energy Board)* (2006), 210 O.A.C. 4 (Ont. C.A.), at paras. 8 and 10-12.

139 In the case before us, however, the Board decided not to submit all costs to a prudence review. Instead, it stated that it would use two kinds of review. The first would apply to "forecast costs", that is, those over which a utility retains discretion and can still be reduced or avoided. It explained in its reasons that it would review such costs using a wide range of evidence, and that the onus was on the utility to demonstrate that its forecast costs were reasonable:

> When considering forecast costs, the onus is on the company to make its case and to support its claim that the forecast expenditures are reasonable. The company provides a wide spectrum of such evidence, including business cases, trend analysis, benchmarking data, etc. The test is not dishonesty, negligence, or wasteful loss; the test is reasonableness. And in assessing reasonableness, the Board is not constrained to consider only factors pertaining to [Ontario Power Generation]. The Board has the discretion to find forecast costs unreasonable based on the evidence — and that evidence may be related to the cost/benefit analysis, the impact on ratepayers, comparisons with other entities, or other considerations.
>
> The benefit of a forward test period is that the company has the benefit of the Board's decision in advance regarding the recovery of forecast costs. To the extent costs are disallowed, for example, a forward test period provides the company with the opportunity to adjust its plans accordingly. In other words, there is not necessarily any cost borne by shareholders (unless the company decides to continue to spend at the higher level in any event). [p. 19]

140 A different approach, the Board said, would be applied to those costs the company could not "take action to reduce". These costs, sometimes called "committed costs", represent binding commitments that leave a utility with no discretion about whether to make the payment. The Board explained that it evaluates these costs using a "prudence review", which includes a presumption that the costs were prudently incurred:

> Somewhat different considerations will come into play when undertaking an after-the-fact prudence review. In the case of an after-the-fact prudence review, if the Board disallows a cost, it is necessarily borne by the shareholder. There is no opportunity for the company to take action to reduce the cost at that point. For this reason, the Board concludes there is a difference between the two types of examination, with the after-the-fact review being a prudence review conducted in the manner which includes a presumption of prudence. [p. 19]

141 In *Enersource Hydro Mississauga Inc. (Re)*, for example, the Board concluded that it had to conduct a prudence review when evaluating the costs that Enersource had already incurred:

> This issue concerns expenditures which have largely already been incurred by the company. ... Given that the issue concerns past expenditures which are now in dispute, the Board must conduct a prudence review. [para. 55]

142 As the Board said in its reasons, the prudence review makes sense for committed costs because disallowing costs Ontario Power Generation cannot avoid, forces the utility to pay out of pocket for expenses it has already incurred. This could negatively affect Ontario Power Generation's ability to operate, leading the utility to restructure its relationships with the financial community and its service providers, or even lead to bankruptcy: see Burns et al., at pp. 129-65. These

outcomes would "increase capital costs and utility rates above the levels that would exist with a limited prudence penalty", forcing Ontario consumers to pay higher electricity bills: Burns et al., at p. vi.

143 The issue in this appeal therefore centres on the Board assessing *all* compensation costs in Ontario Power Generation's collective agreements as adjustable forecast costs, without determining whether any of them were costs for which "[t]here is no opportunity for the company to take action to reduce". The Board did not actually call them forecast costs, but by saying that "collective agreements may make it difficult to eliminate positions quickly" and that "changes to union contracts ... will take time" (pp. 85 and 87), the Board was clearly treating them as reducible in theory. Moreover, the fact that it failed to apply the prudence review it said it would apply to non-reducible costs confirms that it saw the collectively bargained commitments as adjustable.

144 The Board did not explain why it considered compensation costs in collective agreements to be adjustable forecast costs, but the effect of its approach was to deprive Ontario Power Generation of the benefit of the Board's assessment methodology that treats committed costs differently. In my respectful view, the Board's failure to separately assess the compensation costs committed as a result of the collective agreements from other compensation costs, ignored not only its own methodological template, but labour law as well.

145 Ontario Power Generation was a party to binding collective agreements with the Power Workers' Union and the Society of Energy Professionals covering most of the relevant period. At the time of the application, it had already entered into a collective agreement with the Power Workers' Union for the period of April 1, 2009 to March 31, 2012.

146 Its collective agreement with the Society of Energy Professionals, which required resolution by binding mediation-arbitration in the event of contract negotiations disputes, expired on December 31, 2010. As a result of a bargaining impasse, the terms of a new collective agreement for January 1, 2011 to December 31, 2012 were imposed by legally binding arbitration: *Ontario Power Generation v. Society of Energy Professionals*, [2011] O.L.A.A. No. 117 (Ont. Arb.).

147 The collective agreements with the Power Workers' Union and the Society of Energy Professionals prescribed the compensation rates for staff positions held by represented employees, strictly regulated staff levels at Ontario Power Generation's facilities, and limited the utility's ability to unilaterally reduce its compensation rates and staffing levels. The collective agreement with the Power Workers' Union, for example, stipulated that there would be no involuntary layoffs during the term of the agreement. Instead, Ontario Power Generation would be required either to relocate surplus staff or offer severance in accordance with rates set out in predetermined agreements between the utility and the union: "Collective Agreement between Ontario Power Generation Inc. and Power Workers' Union", April 1, 2009 to March 31, 2012, at art. 11.

148 Similarly, Ontario Power Generation's collective agreement with the Society of Energy Professionals severely limited the utility's bargaining power and control over compensation levels. When the contract between Ontario Power Generation and the Society of Energy Professionals expired on December 31, 2010, the utility's bargaining position had been that its sole shareholder, the Province of Ontario, had directed that there be a zero net compensation increase over the next two-year term. The parties could not reach an agreement and the dispute was therefore referred to binding arbitration as required by previous negotiations. The resulting award by Kevin M. Burkett provided mandatory across-the-board wage increases of three per cent on January 1, 2011, two per cent on January 1, 2012, and a further one per cent on April 1, 2012: *Ontario Power Generation v. Society of Energy Professionals*, at paras. 1, 9, and 28.

149 The obligations contained in these collective agreements were immutable and legally binding commitments: *Labour Relations Act, 1995*, s. 56. As a result, Ontario Power Generation was prohibited from unilaterally reducing the staffing levels, wages, or benefits of its unionized workforce. These agreements therefore did not just leave the utility "with limited flexibility regarding overall compensation rates or staffing levels", as the majority notes (at para. 84), they made it *illegal* for the utility to alter the compensation and staffing levels of 90 per cent of its regulated workforce in a manner that was inconsistent with its commitments under the agreements.

150 Instead, the Board, applying the methodology it said it would use for the utility's forecast costs, put the onus on Ontario Power Generation to prove the reasonableness of its costs and concluded that it had failed to provide "compelling evidence" or "documentation or analysis" to justify compensation levels: p. 85. Had the Board used the approach it said it would use for costs the company had "no opportunity ... to reduce", it would have used an after-the-fact prudence review, with a rebuttable presumption that the utility's expenditures were reasonable.

151 Applying a prudence review to these compensation costs would hardly, as the majority suggests, "have conflicted with the burden of proof in the *Ontario Energy Board Act, 1998*". To interpret the burden of proof in s. 78.1(6) of the *Ontario Energy Board Act* so strictly would essentially prevent the Board from ever conducting a prudence review, notwithstanding that it has comfortably done so in the past and stated, even in its reasons in this case, that it would review committed costs using an "after-the-fact prudence review" which "includes a presumption of prudence". Under the majority's logic, however, since a prudence review always involves a presumption of prudence, the Board would not only be limiting its methodological flexibility, it would be in breach of the Act.

152 The application of a prudence review does not shield the utility's compensation costs from scrutiny. As the Court of Appeal observed, a prudence review

> does not mean that the [Board] is powerless to review the compensation rates for [Ontario Power Generation]'s unionized staff positions or the number of those positions. In a prudence review, the evidence may show that the presumption of prudently incurred costs should be set aside, and that the committed compensation rates and staffing levels were not reasonable; however, the [Board] cannot resort to hindsight, and must consider what was known or ought to have been known at the time. A prudence review allows for such an outcome, and permits the [Board] both to fulfill its statutory mandate and to serve as a market proxy, while maintaining a fair balance between [Ontario Power Generation] and its customers. [para. 38]

153 The majority's suggestion (at para. 114) that "if the legislature had intended for costs under collective agreements to also be inevitably imposed on consumers, it would not have seen fit to grant the Board oversight of utility compensation costs", is puzzling. The legislature did not intend for *any* costs to be "inevitably" imposed on consumers. What it intended was to give the Board authority to determine just and reasonable payment amounts based on Ontario Power Generation's existing and proposed commitments. Neither collective agreements nor any other contractual obligations were intended to be "inevitably" imposed. They were intended to be inevitably considered in the balance. But it is precisely because of the unique nature of binding commitments that the Board said it would impose a different kind of review on these costs.

154 It may well be that Ontario Power Generation has the ability to manage some staffing levels through attrition or other mechanisms that did not breach the utility's commitments under its collective agreements, and that these costs may therefore properly be characterized as forecast costs. But no factual findings were made by the Board about the extent of any such flexibility. There is in fact no evidence in the record, nor any evidence cited in the Board's decision, setting out what proportion of Ontario Power Generation's compensation costs were fixed and what proportion remained subject to the utility's discretion. The Board made virtually no findings of fact regarding the extent to which the utility could reduce its collectively bargained compensation costs. On the contrary, the Board, as Aitken J. noted, "lumped" all compensation costs together, acknowledged that reducing those in the collective agreements would "take time" and "be difficult", and dealt with them as globally adjustable.

155 Given that collective agreements are legally binding, it was unreasonable for the Board to assume that Ontario Power Generation could reduce the costs fixed by these contracts in the absence of any evidence to that effect. To use the majority's words, these costs are "legal obligations that leave [the utility] with no discretion as to whether to make the payment in the future" (para. 82). According to the Board's own methodology, costs for which "[t]here is no opportunity for the company to take action to reduce" are entitled to "a presumption of prudence": p. 19.

156 Disallowing costs that Ontario Power Generation is legally required to pay as a result of its collective agreements, would force the utility and the Province of Ontario, the sole shareholder, to make up the difference elsewhere. This includes the possibility that Ontario Power Generation would be forced to reduce investment in the development of capacity and facilities. And because Ontario Power Generation is Ontario's largest electricity generator, it may not only threaten the "financial viability" of the province's electricity industry, it could also imperil the assurance of reliable electricity service.

157 The majority nonetheless assumes that the ongoing relationship between Ontario Power Generation and the unions should give the Board greater latitude in disallowing the collectively bargained compensation costs than it would have had if it applied a no-hindsight, presumption-of-prudence analysis. It also accepts the Board's conclusion that Ontario Power Generation's collectively bargained compensation costs may be "excessive", and therefore concludes that the Board was reasonable in choosing to avoid the "prudence" test in order to so find. This approach finds no support even in the methodology the Board set out for itself for evaluating just and reasonable payment amounts.

158 In my respectful view, selecting a test which is more likely to confirm an assumption that collectively bargained costs are excessive, misconceives the point of the exercise, namely, to determine whether those costs were in fact excessive. Blaming collective bargaining for what are *assumed* to be excessive costs, imposes, with respect, the appearance of an ideologically driven conclusion on what is intended to be a principled methodology based on a distinction between committed and forecast costs, not between costs which are collectively bargained and those which are not.

159 I recognize that the Board has wide discretion to fix payment amounts that are "just and reasonable" and, subject to certain limitations, to "establish the ... methodology" used to determine such amounts: O. Reg. 53/05, s. 6, *Ontario Energy Board Act, 1998*, s. 78.1. That said, once the Board establishes a methodology to determine what is just and reasonable, it is, at the very least, required to faithfully apply that approach: see *TransCanada Pipelines Ltd. v. Canada (National Energy Board)* (2004), 319 N.R. 171 (F.C.A.), at paras. 30-32, per Rothstein J.A. This does not mean that collective agreements "supersede" or "trump" the Board's authority to fix payment amounts; it means that once the Board selects a methodology for itself for the exercise of its discretion, it is required to follow it. Absent methodological clarity and predictability, Ontario Power Generation would be left in the dark about how to determine what expenditures and investments to make and how to present them to the Board for review. Wandering sporadically from approach to approach, or failing to apply the methodology it declares itself to be following, creates uncertainty and leads, inevitably, to needlessly wasting public time and resources in constantly having to anticipate and respond to moving regulatory targets.

160 In disallowing $145 million of the compensation costs sought by Ontario Power Generation on the grounds that the utility could reduce salary and staffing levels, the Board ignored the legally binding nature of the collective agreements and failed to distinguish between committed compensation costs and those that were reducible. Whether or not one can fault the Board for failing to use a particular methodology, what the Board can unquestionably be analytically faulted for, is evaluating all compensation costs fixed by collective agreements as being amenable to adjustment. Treating these compensation costs as reducible was, in my respectful view, unreasonable.

161 I would accordingly dismiss the appeal, set aside the Board's decision, and, like the Court of Appeal, remit the matter to the Board for reconsideration in accordance with these reasons.

Appeal allowed.

Pourvoi accueilli.

End of Document

Most Negative Treatment: Distinguished
Most Recent Distinguished: Bell Canada v. Canadian Radio-Television & Telecommunications Commission | 2009 SCC 40, 2009 CarswellNat 2717, 2009 CarswellNat 2718, 92 Admin. L.R. (4th) 157, J.E. 2009-1708, 392 N.R. 323, [2009] A.C.S. No. 40, [2009] S.C.J. No. 40, 310 D.L.R. (4th) 608, [2009] 2 S.C.R. 764, 180 A.C.W.S. (2d) 843 | (S.C.C., Sep 18, 2009)

1989 CarswellNat 586
Supreme Court of Canada

Bell Canada v. Canadian Radio-Television & Telecommunications Commission

1989 CarswellNat 586, 1989 CarswellNat 697, [1989] 1 S.C.R. 1722, [1989] S.C.J. No. 68, 16 A.C.W.S. (3d) 1, 38 Admin. L.R. 1, 60 D.L.R. (4th) 682, 97 N.R. 15, J.E. 89-994, EYB 1989-67230

CDN. RADIO-TELEVISION & TELECOMMUNICATIONS COMM. v. BELL CAN. et al.

Lamer, Wilson, La Forest, L'Heureux-Dubé, Sopinka, Gonthier, and Cory JJ.

Heard: Febuary 21, 1989
Judgment: June 22, 1989
Docket: Doc. No. 20525

Counsel: *Raynold Langlois, Q.C.* , *Greg Van Koughnett* and *Luc Huppé* , for appellant.
Gérald Tremblay, Q.C. , and *Michel Racicot*, for respondent.
Graham Garton , for Attorney General of Canada.
Janet Yale , for Consumers' Association of Canada.
Kenneth Engelhart , for Canadian Business Telecommunications Alliance.
Michel Ryan , for C.N.C.P. Telecommunications
Andrew Roman and *Robert Horwood*, for National Anti-Poverty Organization.

Subject: Public
Related Abridgment Classifications
Communications law
II Regulatory commissions
  II.1 C.R.T.C. (Canadian Radio-television and Telecommunications Commission)
    II.1.a Powers and duties
Headnote
Communications Law --- Regulatory commissions — C.R.T.C. (Canadian Radio-Television and Telecommunications Commission) — Powers and duties
Appeals — Statutory appeal on questions of law and jurisdiction — No scope for curial deference towards agency's decisions — Specialization of duties requiring respect for decision on matters within expertise — Power of C.R.T.C. to revisit interim rate orders being question of jurisdiction not within C.R.T.C.'s expertise — Method of rectifying unjust or unreasonable rates within realm of C.R.T.C.'s expertise.
Jurisdiction — C.R.T.C. making order for one-time credit to rectify excessive revenues found to have been earned by Bell Can. as result of interim orders — C.R.T.C. having authority to revisit interim orders and to rectify adverse effects of such orders as part of final order — Method of rectification for C.R.T.C. provided not unreasonable — One-time credit for existing customers reasonable albeit not perfect compensation.

In March 1984, BC applied to the C.R.T.C. for a general rate increase. Because of the time it was going to take to deal finally with that application resulting in allegedly severe prejudice to BC's fiscal situation, the C.R.T.C. responded favourably to its request for an interim rate increase. This was set at 2 per cent effective January 1, 1985. In the order allowing the interim rate increase, the C.R.T.C. indicated that it was subject to re-evaluation as part of any final order. Notwithstanding the concerns over profitability that had prompted the interim order, BC's financial situation improved dramatically thereafter. This prompted another interim order by the C.R.T.C. in 1985 which resulted in a roll back of BC's rates (also expressed to be interim) to those in place prior to the March 1984 application. Then, BC itself sought to withdraw its application for a general rate increase. In effect, the C.R.T.C. rejected this application in that it proceeded to a hearing into the financial situation of BC. The upshot of this was a finding that BC's revenues during 1985 and 1986 were $206 million more than were justified in terms of what was held to be an appropriate rate of return. As a result, the C.R.T.C. ordered that BC redistribute those excess revenues to certain classes of customer in the form of a one-time credit.

Under the *Railway Act* , BC's tolls were subject to approval by the C.R.T.C. as well as revision from time to time. Section 340(1) required that such tolls be "just and reasonable". Subsection 5 of that section also conferred on the C.R.T.C. authority to make orders with respect to tolls "[i]n all other matters not expressly provided for" in the rest of the section. Under the *National Transportation Act* , s. 52 the C.R.T.C. was given authority to deal of its own motion with matters assigned to it under the *Railway Act* , while by s. 60(2) it was given power to make interim orders and reserve further directions for a subsequent hearing. Section 66 then clothed the C.R.T.C. with authority to review, rescind, change, alter or vary its orders and decisions. Finally, under s. 68(1), provision was made for an appeal with leave on law and jurisdiction from C.R.T.C. orders to the Federal Court of Appeal.

BC appealed against the order and the Federal Court of Appeal (Hugesson J. dissenting) allowed the appeal and set aside the credit to customers ((1987), [1988] 1 F.C. 296). The C.R.T.C. then obtained leave to appeal to the Supreme Court of Canada.

Held:

The appeal was allowed. The order of the C.R.T.C. was reinstated.

Where the relevant legislation created a right of appeal to a Court from the decision of an administrative tribunal, there was no place for curial deference to decisions of that tribunal associated with decisions of tribunals protected by privative or finality clauses. Moreover, while even here, the concept of specialization of duties indicated the need for some measure of deference to decisions of the C.R.T.C. within its area of expertise, that did not apply to issues of jurisdiction such as the scope of the authority of the C.R.T.C. to issue interim decisions. On such issues, the Court was entitled to simply disagree with the Tribunal. In contrast, however, on the issue of the choice of the most appropriate remedy from among those available to achieve just and reasonable rates, the C.R.T.C. was entitled to a measure of deference. This, rather than the interpretation of the *Railway Act* and the *National Transportation Act* , was what the C.R.T.C. had been established to do. The statutory scheme of the powers conferred on the C.R.T.C. indicated that its authority to make interim orders was to be interpreted so as to facilitate its task of ensuring that telephone rates were always "just and reasonable".

It was a necessary incident of the authority to regulate tolls and tariffs that the C.R.T.C. could regulate BC's level of revenues and its return on its equity.

While the C.R.T.C.'s order of a one-time credit was not strictly retrospective in that it did not actually replace or substitute the rates that were charged during the interim period, nevertheless, it was retrospective in the sense that it was designed to remedy the excessive rates charged during that period. However, even accepting this characterization of the order, the C.R.T.C. had jurisdiction to make it. Indeed, the authority to review interim orders retrospectively was the key distinction between interim orders and final orders, given the authority of the C.R.T.C. to at any time review final orders prospectively. It was inherent in the nature of interim orders that they could, as here, be revised and modified in a retrospective manner by a final decision. This conclusion also followed from the fact that interim rate orders were not based on the same criteria as final orders. The intent of interim rate orders was not to afford a preliminary adjudication on the merits, but rather to relieve the applicant from the deleterious effects of lengthy proceedings. Such was the nature of the order made here. Moreover, throughout, the C.R.T.C. had indicated its intention as part of the final order to review the rates charged during the interim period.

While, unlike other statutes, the power to review interim orders retrospectively was not set out expressly in the legislation, it clearly existed by virtue of necessary implication from the statutory scheme and purpose. To deny the C.R.T.C. this authority would be to sterilize its powers through an overly technical interpretation. More specifically, the whole thrust of the legislation was in the direction of ensuring that rates charged were at all times just and reasonable. To deny the C.R.T.C. the authority to undo unjust or unreasonable interim rate orders would defeat that purpose. In this respect, it mattered not that the regulatory scheme involved was one involving positive approval on application rather than negative disallowance after complaint. The addition of a power to make interim orders as part of a positive approval scheme conferred on the C.R.T.C. the flexibility to make such an order from the date of the application had been made but, as a corollary, also involved the authority to remedy as part of the final order any discrepancy between the rate of return yielded by the interim order and that allowed in the final decision.

Given the C.R.T.C.'s authority to revisit the period during which the interim orders were in effect, this necessarily involved the authority to remedy any unjustness or unreasonableness in those interim rates. The statutory basis for such an order was to be found in the breadth of s. 340(5).

In so doing, the C.R.T.C. was not confined to the extra revenues generated by the 2 per cent interim rate increase but rather had authority with respect to all of BC's revenues generated from the date of the commencement of the proceedings.

While the order did not necessarily benefit the customers who were actually charged excessive rates, nevertheless, the nature and extent of such orders were within the C.R.T.C.'s jurisdiction and the particular order, while not effecting perfect compensation, was clearly reasonable given the difficulties associated with actually compensating all those who had paid excessive rates.

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Words and phrases considered:

INTERIM ORDER

. . . one of the differences between interim and final orders must be that interim decisions may be reviewed and modified in a retrospective manner by a final decision. It is inherent in the nature of interim orders that their effect, as well as any discrepancy between the interim order and the final order, may be reviewed and remedied by the final order . . . It is the interim nature of the order which makes it subject to further retrospective directions.

POSITIVE APPROVAL SCHEME

Much was said in argument about the difference between positive approval schemes and negative disallowance schemes, with respect to the power to act retrospectively. The first category includes schemes which provide that the administrative agency is the only body having statutory authority to approve or fix tolls payable to utility companies; these schemes generally stipulate that tolls shall be "just and reasonable" and that the administrative agency has the power to review these tolls on a proprio motu basis, or upon application by an interested party. The second category includes schemes which grant utility companies the right to fix tolls as they wish, but also grant users the right to complain before an administrative agency which has the power to vary those tolls if it finds that they are not "just and reasonable". It has generally been found that negative disallowance schemes provide the power to make orders which are retroactive to the date of the application, by the ratepayer who claims that the rates are not "just reasonable". On the other hand, positive approval schemes have been found to be exclusively prospective in nature and not to allow orders applicable to periods prior to the final decision itself.

APPEAL from Federal Court of Appeal, reported at (1987), [1988] 1 F.C. 296 , allowing an appeal from an order of the C.R.T.C.

The judgment of the Court was delivered by *Gonthier J.*:

1 The present case is an appeal against a decision of the Federal Court of Appeal [reported at (1987), [1988] 1 F.C. 296], which quashed one of the orders made by the appellant in Telecom Decision C.R.T.C. ["Decision"] 86-17. The impugned order compelled the respondent to distribute $206 million in excess revenues earned in the years 1985 and 1986 through a one-time credit to be granted to certain classes of customers. The respondent does not contest the factual findings on which Decision 86-17 is based, nor does it claim that this order would unduly prejudice its financial position. None of the other orders made in Decision 86-17 are challenged.

2 The appellant claims that the purpose of the challenged order was to provide telephone users with a remedy against interim rates, which turned out to be excessive, on the basis of the findings of fact made by the appellant following a final hearing, held in the summer of 1986, for the purpose of setting rates to be charged by the respondent in the years 1985 and following. These findings of fact are reported in Decision 86-17. Since this case turns on the proper characterization of the one-time credit order made in Decision 86-17, it is important to describe the procedural history of the administrative proceedings which led to the order now contested by the respondent.

I — The Facts

3 On March 28, 1984, the respondent applied for a general rate increase under Part VII of the C.R.T.C. Telecommunications Rules of Procedure, SOR/79-554 [under the *National Transportation Act* , R.S.C. 1985, c. N-20], which provides for a summary public process to deal with special applications. The respondent claimed that the Canadian Government's restraint program restricting rate increases of federally regulated utilities to 5 per cent and 6 per cent was sufficient justification to dispense with the normal procedure for general rate increase applications set out in Part III of the C.R.T.C. Telecommunications Rules of Procedure. In Decision 84-15, the appellant rejected this application on the ground that the respondent had failed to use the appropriate procedure as set out in Part III of these rules. However, the appellant indicated that if the respondent was to suffer financial prejudice as a result of the delays involved in preparing for the more complex procedure set out in part III, it could always apply for interim relief pending a hearing and a decision on the merits, at pp. 8-9:

> The Commission recognizes that, in 1985 and beyond, in the absence of rate relief, a deterioration in the Company's financial position could occur. In this regard, if the Company should find it necessary to file an application for a general rate increase under Part III of the Rules, the Commission would be prepared to schedule a public hearing

> on such an application in the fall of 1985. *Should Bell consider it necessary to seek rate increases to come into effect earlier in 1985 than this schedule would allow, it may of course apply for interim relief* . In the event Bell were to seek such interim relief, it would be open to the Company to suggest that the Commission's traditional test for determining interim rate applications is overly restrictive in light of the Commission hearing schedule and to put forward proposals for an alternative test for consideration.

(Emphasis added.) On September 4, 1984, the respondent filed an application for a general rate increase based on 1985 financial data which would come into effect on January 1, 1986. At the same time, the respondent applied for an interim rate increase of 3.6 per cent.

4 In Decision 84-28, rendered on December 19, 1984, the appellant set out the following policy previously adopted in Decision 80-7 with respect to the granting of interim rate increases, at pp. 8-9:

> The Commission's policy concerning interim rate increases, enunciated in Decision 80-7, is as follows:
>
> The Commission considers that, as a rule, general rate increases should only be granted following the full public process contemplated by Part III of its Telecommunications Rules of Procedure. In the absence of such a process, general rate increases should not in the Commission's view be granted, even on an interim basis, except where special circumstances can be demonstrated. *Such circumstances would include lengthy delays in dealing with an application that could result in a serious deterioration in the financial condition of an applicant absent a general interim increase* .

(Emphasis added.) The respondent argued that its financial situation warranted an interim rate increase and did not question the reasonableness of this policy. The appellant agreed with the respondent's submission that, in the absence of interim rate increases, it might suffer from serious financial deterioration and awarded an interim rate increase of 2 per cent. In this decision, the appellant required the respondent to prepare for a hearing to be held in the fall of 1985 for the purpose of assessing the respondent's application for a final order increasing its rates on the basis of 2 test years, 1985 and 1986. Decision 84-28 also states the reasons why the interim rate increase was set at 2 per cent, at p. 10:

> In determining the amount of interim rate increases required under the circumstances, the Commission has taken into account the following factors:
>
> 1) While the company stated that an interest coverage ratio of 4.0 times is required, the Commission regards the maintenance of the coverage ratio of 3.8 times, projected by the Company for 1984, as sufficient for the purposes of this interim decision.
>
> 2) With regard to the level of ROE ['return on equity'], the Commission is of the view that, for 1985, *and subject to review in the course of its consideration of the Company's general rate increase application in the fall of 1985* , 13.7% is appropriate for determining the amount of rate increases to be permitted pursuant to this interim increase application.
>
> 3) With regard to the Company's 1985 expense forecasts, the Commission notes that the inflation factor used by the Company is higher than the current consensus forecast of the inflation rate for 1985 and considers that Bell's forecast of its 1985 Operating Expenses could be overestimated by approximately $25 million.
>
> Taking the above factors into account, the Commission has decided that an interim rate increase of 2% for all services in respect of which rate increases were requested by the Company in the interim application is appropriate at this time. This increase is expected to generate additional revenues of $65 million from 1 January 1985 to 31 December 1985. *To permit the review of the Company's 1985 revenue requirement by the Commission at the fall 1985 public hearing, Bell is directed to file its 4 June 1985 general rate increase application on the basis of two test years, 1985 and 1986* .

(Emphasis added.) The reasons set out in the appellant's decision indicate that the interim rate increase was calculated on the basis of financial information provided by the respondent without placing this information under the scrutiny normally associated with hearings made under Part III of the C.R.T.C. Telecommunications Rules of Procedure. Furthermore, the appellant clearly expressed the intention to review this interim rate increase in its final decision on the respondent's application for a general rate increase, on the basis of financial information for the years 1985 and 1986. Given the content of the appellant's final decision, it is also important to note that the 2 per cent interim rate increase was calculated on the assumption that the respondent's return on equity for 1985 should be 13.7 per cent subject to review in the final decision.

5 The respondent's financial situation later improved thereby reducing the necessity to proceed with an early hearing for the purpose of obtaining a general and final rate increase. By a letter dated March 20, 1985, the respondent asked for this hearing to be postponed to February 10, 1986, suggesting however that the 2 per cent interim increase be given immediate final approval. In C.R.T.C. Telecom Public Notice 1985-30 dated April 16, 1985, the appellant granted the postponement but refused to grant the final approval requested by the respondent without further investigation into this matter. The Commission added that it would monitor the respondent's financial situation on a monthly basis and ordered the filing of monthly statements, at p. 4:

> In view of the improving trend in the Company's financial performance, the Commission further directs as follows:
>
> Bell Canada is to provide to the Commission for the balance of 1985, within 30 days after the end of each month, commencing with April 1985, a full year forecast of revenues and expenses on a regulated basis for the year 1985, together with the estimated financial ratios including the projected regulated return on common equity.
>
> The Commission will monitor the Company's financial performance during 1985, *in order to determine whether any further rate action may be necessary* .

(Emphasis added.) Again, the appellant clearly expressed its intention to prevent abuse of interim rate increases.

6 After a review of the July financial information filing ordered in C.R.T.C. Telecom Public Notice 1985-30, the appellant asked the respondent to provide reasons why the interim rate increase of 2 per cent should remain in force given its improved financial situation. The respondent was unable to convince the appellant that this interim increase remained necessary to avoid financial deterioration and was accordingly ordered to file revised tariffs effective as of September 1, 1985, at pp. 4-5 of Decision 85-18:

> In view of the improving trend in Bell's financial performance, the Commission is satisfied that the company no longer needs the 2% interim increases *which were awarded in Decision 84-28 in order to avoid serious financial deterioration in 1985* . Accordingly, Bell is directed to file revised tariffs forthwith, with an effective date of 1 September 1985, to suspend these increases.
>
> In arriving at its decision the Commission has estimated that, *with interim rates in effect for the complete year* , the company would earn an ROE ['return on equity'] of approximatively 14.5% in 1985, *a return well in excess of the 13.7% considered appropriate for determining the 2% interim rate increases* . The Commission also projected that interest coverage would be approximately 3.9 times. This would improve on the actual 1984 coverage of 3.8 times. These estimates are not significantly different from Bell's current expectation of its 1985 result.
>
> *The Commission will make its final determination of Bell's revenue requirement for the year 1985 in the general rate proceeding currently scheduled to commence with an application to be filed on 10 February 1986* .

(Emphasis added.) As a result of this decision, the respondent was forced to charge the rates effective before its application for a rate increase, filed on March 28, 1984. However, even though the rates effective as of September 1, 1985 were numerically identical to the rates in force under the previous final decision prior to the interim increase, these new rates remained interim in nature. In fact, the appellant reiterated its intention to review the rates actually charged during 1985 and 1986.

7 On October 31, 1985, the respondent decided not to proceed with its application for a general rate increase and requested that its procedures be withdrawn. In C.R.T.C. Telecom Public Notice 1985-85, the appellant decided to review the respondent's financial situation and therefore the appropriateness of its rates, notwithstanding its request to withdraw its initial application for a general rate increase, at pp. 3-4:

> *In light of these forecasts and the degree to which the company's rate structure is expected to be considered in separate proceedings, Bell stated that it wished to refrain from proceeding with the application schedule to be filed on 10 February 1986* . Accordingly, the company requested the withdrawal of the amended Directions on Procedure issued by the Commission in Public Notice 1985-30.
>
> . . . . .
>
> The Commission notes that the appropriate rate of return for Bell has not been reviewed in an oral hearing since the proceeding which culminated in *Bell Canada — General Increase in Rates* , Telecom Decision CRTC 81-15, 20 September 1981 (Decision 81-15). *The Commission considers that, given Bell's current forecasts, it would be appropriate to review the company's cost of equity for the years 1985, 1986 and 1987 in the proceeding scheduled for 1986* . Such a review would allow consideration of the changing financial and economic conditions since Decision 81-15 and the impact of Bell's corporate reorganization on its rate of return. The Commission notes that other issues arising from the reorganization would also be addressed in the 1986 proceeding.

(Emphasis added.) This interim decision indicates that the appellant wished to continue the original rate review procedure initiated by the respondent in March 1984. Thus, the rates in force as of January 1, 1985 until the final decision now challenged by the respondent were interim rates subject to review.

8 The hearing which led to the final decision lasted from June 2 to July 16, 1986 and this final decision, Decision 86-17, was rendered on October 14, 1986. In this decision, the appellant first established appropriate levels of profitability for the respondent on the basis of its return on equity. The appellant then calculated the amount of excess revenues earned by the respondent in 1985 and 1986, along with the necessary reduction in forecasted revenues for 1987. It was found that the respondent had earned excess revenues of $63 million in 1985 and $143 million in 1986, for a total of $206 million, at p. 93:

> After making further adjustments for the compensation for temporarily transferred employees and including the regulatory treatment for non-integral subsidiary and associated companies, the Commission has determined that a revenue requirement reduction of $234 million would provide the company with a 12.75% ROE ['return on equity'] on a regulated basis in 1987. Similarly, the Commission has determined that $143 million is the required revenue reduction to achieve the upper end of the permissible ROE on a regulated basis in 1986, 13.25%. With respect to 1985, after making the adjustments set out in this decision, the Commission has determined that Bell earned excess revenues in the amount of $63 million, the deduction of which would provide 13.75%, the upper end of the permissible ROE on a regulated basis.

It is important to note that the evidence and the arguments presented by the interested parties as well as interveners were carefully scrutinized by the appellant, at pp. 77-92 of Decision 86-17. It is for all practical purposes impossible to engage in such a meticulous and painstaking analysis of all relevant facts when faced with an application for interim relief. Finally, it is also useful to note that the permissible return on equity of 13.7 per cent allowed by the appellant in its interim decision, Decision 84-28, was increased to 13.75 per cent in Decision 86-17. Thus, the appellant realized that the interim rates approved for 1985 yielded greater rates of return than initially anticipated, and that the rate of return actually recorded for that year even exceeded the greater allowable rate of return fixed in the final decision, Decision 86-17. Such differences between projected and actual rates of return are common and certainly call for a high level of flexibility in the exercise of the appellant's regulatory duties.

9 The Commission decided that the respondent could not retain excess revenues earned on the basis of interim rates and issued the order now challenged by the respondent in order to provide a remedy for this situation. This order reads as follows, at pp. 95-96:

> *Concerning the excess revenues for the years 1985 and 1986, the Commission directs that the required adjustments be made by means of a one-time credit to subscribers of record, as of the date of this decision, of the following local services* : residence and business individual, two-party and four-party line services; PBX trunk services; centrex lines; enhanced exchange-wide dial lines; exchange radio-telephone service; service-system service and information system access line service. *The Commission directs that the credit to each subscriber be determined by pro-rating the sum of the excess revenues for 1985 and 1986 of $206 million in relation to the subscriber's monthly recurring billing for the specified local services provided as of the date of this decision* . The Commission further directs that the work necessary to implement the above directives be commenced immediately and that the billing adjustments be completed by no later than 31 January 1987. Finally, the Commission directs the company to file a report detailing the implementation of the credit by no later than 16 February 1987.
>
> *The Commission considers that 1987 excess revenues are best dealt with Gthrough rate reductions to be effective 1 January 1987* .

(Emphasis added.) Although the respondent always charged rates approved by the appellant, the appellant found it necessary to make sure that its assessment of allowable revenues for 1985 and 1986 would be complied with. The appellant argues that the order now challenged by the respondent was the most efficient way of redistributing these excess revenues to the respondent's customers even though they would not necessarily be refunded to those who actually had to pay the rates in force during that period.

10 It is therefore obvious that the appellant only allowed interim rates to be charged after January 1, 1985 on the assumption that it would review these rates in a hearing to be held in order to deal with an application for a general rate increase. Every interim decision which led to Decision 86-17 confirmed the appellant's intention to review the interim rates at the final hearing. Finally, the interim rates were ordered for the purpose of preventing any serious deterioration in the respondent's financial situation while awaiting for a final decision on the merits. Of necessity, these interim rates were determined on the basis of incomplete evidence presented by the respondent. It cannot be said that the purpose of the interim rate increase ordered by the appellant was to serve as a temporary final decision.

II — The Issue and the Arguments Raised by the Parties

11 In this Court, as well as in the Federal Court of Appeal, the parties have agreed that the only issue arising out of the facts of this case is whether the appellant had jurisdiction to order the respondent to grant a one-time credit to its customers. The appellant's findings of fact, its determination with respect to the respondent's revenue requirements for 1985 and 1986, and its computation of the amount of excess revenues earned during this period are not contested by the respondent. In my opinion, this issue can be divided in two subquestions:

> 1. Whether the appellant had the legislative authority to review the revenues made by the respondent during the period when interim rates were in force;
>
> 2. Whether the appellant had jurisdiction to make an order compelling the respondent to grant a one-time credit to its customers.

12 The main arguments raised by the appellant can be summarized as follows:

> 1. The *Railway Act* , R.S.C. 1985, c. R-3 and the *National Transportation Act* , R.S.C. 1985, c. N-20 grant the appellant the power to review the period during which a regulated entity was allowed to charge interim rates, for

the purpose of comparing the revenues earned during this period to the appropriate level of revenues set in the final decision;

2. The power to make a one-time credit order is necessarily ancillary to the power to review the period during which interim rates were charged, and the appellant has jurisdiction to determine the most efficient method of providing a remedy in cases where excess revenues were made.

13 The main arguments raised by the respondent can be summarized as follows:

1. The power to set tolls and tariffs does not include the power to review and make orders with respect to the respondent's level of revenues;

2. The appellant has no power to make a one-time credit order with respect to revenues earned as a result of having charged rates which the respondent, by virtue of the *Railway Act* , was obliged to charge, whether these rates were set by an interim order or by a final order.

14 Counsel for the National Anti-Poverty organization ("N.A.P.O.") has also argued that the appellant's decisions concerning the interpretation of statutes which grant them jurisdiction to deal with certain matters are entitled to curial deference and cannot be reviewed unless they are patently unreasonable. This argument raises the issue of the scope of review allowed by s. 68(1) of the *National Transportation Act* and must be dealt with prior to any analysis of the relevant statutory provisions claimed to be the source of the appellant's jurisdiction to make the one-time credit order found in Decision 86-17.

15 The present case raises difficult questions of statutory interpretation and it will therefore be necessary to examine the relevant provisions of the *wRailway Act* and the *National Transportation Act* before moving to a detailed analysis of the decision of the Federal Court of Appeal and the arguments raised by the parties.

III — Relevant Legislative Provisions

16 The appellant derives its power to regulate the telephone industry from ss. 334 to 340 of the *Railway Act* ("Provisions Governing Telegraphs and Telephones") and from ss. 47 et seq. of the *National Transportation Act* ("General Jurisdiction and Powers in Respect of Railways"). The *Railway Act* sets out the general criteria concerning the setting of rates and tariffs to be charged by telephone utility companies, whereas the *National Transportation Act* sets out the appellant's procedural powers in the context of decisions concerning, amongst other matters, telephone rates and tariffs.

17 Sections 335(1), 335(2) and 335(3) of the *Railway Act* (formerly ss. 320(2) and 320(3)) state the principle upon which the appellant's regulatory authority rests, namely, that telephone rates and tariffs are subject to approval by the appellant, cannot be changed without its prior authorization, and may be revised at any time by the appellant:

335. (1) Notwithstanding anything in any other Act, all telegraph and telephone tolls to be charged by a company, other than a toll for the transmission of a message intended for reception by the general public and charged by a company licensed under the *Broadcasting Act, are subject to the approval of the Commission, and may be revised by the Commission from time to time* .

(2) The company shall file with the Commission tariffs of any telegraph or telephone tolls to be charged, and the tariffs shall be in such form, size and style, and give such information, particulars and details, as the Commission by regulation or in any particular case prescribes.

(3) *Except with the approval of the Commission, the company shall not charge and is not entitled to charge any telegraph or telephone toll in respect of which there is default in filing under subsection (2), or which is disallowed by the Commission ...*

(Emphasis added.) The most important requirement governing the appellant's power to set telephone rates is found in s. 340(1) of the *Railway Act* which provides that all such rates must be "just and reasonable":

> 340. (1) *All tolls shall be just and reasonable* and shall always, under substantially similar circumstances and conditions with respect to all traffic of the same description carried over the same route, be charged equally to all persons at the same rate.

(Emphasis added.) Section 340 also prohibits discriminatory telephone rates and gives the appellant the power to suspend, postpone, or disallow a tariff of tolls which is contrary to ss. 335 to 340 and substitute a satisfactory tariff of tolls in lieu thereof.

18 Finally, s. 340(5) of the *Railway Act* gives the appellant the power to make orders with respect to traffic, tolls and tariffs in all matters not expressly covered by s. 340:

> 340....
>
> (5) In all other matters not expressly provided for in this section, the Commission may make orders with respect to all matters relating to traffic, tolls and tariffs or any of them.

Although the power granted by s. 340(5) could be construed restrictively by the application of the ejusdem generis rule, I do not think that such an interpretation is warranted. Section 340(5) is but one indication of the legislator's intention to give the appellant all the powers necessary to ensure that the principle set out in s. 340(1), namely that all rates should be just and reasonable, be observed at all times.

19 Sections 47 et seq. of the *National Transportation Act* set out, from a procedural point of view, the appellant's jurisdiction with respect to the powers granted by the *Railway Act* . Section 49(1) gives the appellant jurisdiction over all complaints concerning compliance with the Act, while s. 49(3) gives the appellant jurisdiction over all matters of fact or law for the purposes of the *Railway Act* and of ss. 47 et seq. of the *National Transportation Act* . However, s. 68(1) provides an appeal to the Federal Court of Appeal, with leave, on any question of law or jurisdiction, and it is under this provision that the respondent has challenged Decision 86-17.

20 In many respects, ss. 47 et seq. of the *National Transportation Act* have been designed to further the policy objectives and the regulatory scheme set out in the *Railway Act* governing the approval of telephone rates and tariffs. Thus, s. 52 of the *National Transportation Act* gives the appellant the power to inquire into, hear or determine, of its own motion or upon request from the Minister, any matter which it has the right to inquire into, hear or determine under the *Railway Act* :

> 52. The Commission may, of its own motion, or shall, on the request of the Minister, inquire into, hear and determine any matter or thing that, under this part or the *Railway Act* , it may inquire into, hear and determine upon application or complaint, and with respect thereto has the same powers as, on any application or complaint, are vested in it by this Act.

Section 52 is therefore the corollary of the appellant's power to "revise [tolls] ... from time to time" found in s. 335(1) of the *Railway Act* . Thus, the appellant has the power to review, from time to time, its own final decisions on a proprio motu basis. Similarly, s. 61 provides that the appellant is not bound by the wording of any complaint or application it hears and may make orders which would otherwise offend the ultra petita rule:

> 61. On any application made to the Commission, the Commission may make an order granting the whole or part only of the application, or may grant such further or other relief, in addition to or in substitution for that applied for, as to the Commission may seem just and proper, as fully in all respects as if the application had been for that partial, other or further relief.

21 By virtue of s. 60(2) of the *National Transportation Act* , the appellant also has the power to make interim orders:

> 60. ...
>
> (2) The Commission may, instead of making an order final in the first instance, make an interim order and reserve further directions either for an adjourned hearing of the matter or for further application.

22 Finally, by virtue of s. 66 of the *National Transportation Act* , the appellant has the power to review any of its past decisions, whether they are final or interim:

> 66. The Commission may review, rescind, change, alter or vary any order or decision made by it or may re-hear any application before deciding it.

23 It is obvious from the legislative scheme set out in the *Railway Act* and the *National Transportation Act* that the appellant has been given broad powers for the purpose of ensuring that telephone rates and tariffs are, at all times, just and reasonable. The appellant may revise rates at any time, either of its own motion or in the context of an application made by an interested party. The appellant is not even bound by the relief sought by such applications, and may make any order related thereto provided that the parties have received adequate notice of the issues to be dealt with at the hearing. Were it not for the fact that the appellant has the power to make interim orders, one might say that the appellant's powers in this area are limited only by the time it takes to process applications, prepare for hearings and analyze all the evidence. However, the appellant does have the power to make interim orders and this power must be interpreted in light of the legislator's intention to provide the appellant with flexible and versatile powers for the purpose of ensuring that telephone rates are always just and reasonable.

24 The question before this Court is whether the appellant has the statutory authority to make a one-time credit order for the purpose of remedying a situation where, after a final hearing dealing with the reasonableness of telephone rates charged during the years under review, it finds that interim rates in force during that period were not just and reasonable. Since there is no clear provision on this subject in the *Railway Act* or in the *National Transportation Act* , it will be necessary to determine whether this power is derived by necessary implication from the regulatory schemes set out in these statutes.

IV — The Decision of the Court Below

25 In the Federal Court of Appeal, the respondent in this Court argued that in order to find statutory authority for the power to make a one-time credit order, it was necessary to find that s. 66 (power to "review, rescind, change, alter or vary" previous decisions) or s. 60(2) (power to make interim orders) of the *National Transportation Act* provide powers to make retroactive orders. Of course, the respondent argued that these provisions did not grant such a power and the majority of the Federal Court of Appeal, composed of Marceau and Pratte JJ. agreed with this argument, Hugessen J. dissenting.

26 Marceau J. held that the appellant in this Court only had the power to fix telephone tolls and tariffs, and that it has no statutory authority to deal with excess revenues or deficiencies in revenues arising as a result of a discrepancy between the rate of return yielded from the interim rates in force prior to the final decision and the permissible rate of return fixed by this final decision. Marceau J. was of the opinion that the wording of s. 66 of the *National Transportation Act* is neutral with respect to retroactivity, and that the presumption against retroactivity should therefore operate. Marceau J. added that the power to make interim orders does not carry with it the power to remedy any discrepancy between interim and final orders because the respondent could not be forced to reimburse revenues earned by charging rates approved by the appellant. Thus, according to Marceau J., the regulatory scheme set out in the *Railway Act* and the *National Transportation Act* is prospective in nature and, in the context of such a scheme, the power to make interim orders only involves the power to make orders "for the time being".

27 Pratte J., who concurred in the result with Marceau J., rejected all arguments based on the retroactive nature of the powers granted by ss. 60(2) and 66 of the *National Transportation Act* . Pratte J. was of the opinion that the impugned order was not retroactive in nature since its effect was to force the respondent to grant a credit in the future rather than change the rates charged in the past in a retroactive manner. Pratte J. then stated that if legislative authority existed for Decision 86-17, it must be found in s. 60(2) of the *National Transportation Act* which provides for "further directions" to be made at a later date following an interim decision. However, Pratte J. was of the opinion that any "further direction" must be in the nature of an order which can be made under s. 60(2) in the first place. It follows from that reasoning that if no one-time credit order can be made by interim order, no "further direction" to that effect can be made under s. 60(2). Pratte J. then agreed with Marceau J. that the respondent could not be forced to reimburse revenues made by charging rates approved by the appellant whether by interim order or by a "further direction" made in a final order.

28 Hugessen J. dissented on the basis that, within the statutory framework set out in the *Railway Act* and the *National Transportation Act* , all orders whether final or interim can, by virtue of ss. 60(2) and 66 of the *National Transportation Act* , be modified by a further prospective order; thus, the proposed rule that interim orders can only be modified by a further prospective order would, in Hugessen J.'s opinion, effectively eliminate any distinction between final and interim orders and defeat the legislator's intention to provide the appellant with a distinct and independent power to make interim orders. In order to differentiate interim orders from final orders, Hugessen J. was of the opinion that the appellant in this Court must have the power to fix just and reasonable rates as of the date at which interim rates came into effect. Thus, only interim rates can be modified in a retrospective manner by a final order. Hugessen J. then stated that the interim rates in force in 1985 and 1986 must not be divided into the previous rate and the interim rate increase of 2 per cent: the resulting rate must be viewed as interim in its entirety because all the rates charged after January 1, 1985 were authorized by interim orders. Finally, Hugessen J. stated that the one-time credit order was a valid exercise of the power to set just and reasonable rates as of January 1, 1985 and that the choice of the appropriate remedy was an "'administrative matter' properly left for the Commission's determination". Hugessen J. also noted that the appellant's order was in substance, though not in form, a "matter relating to tolls and tariffs" within the meaning of s. 340(5) of the *Railway Act* .

V — Analysis

29

a) Curial deference towards the decisions of the C.R.T.C.

30 N.A.P.O. argues that the appellant's decisions are entitled to "curial deference" because of their national importance, and that these decisions should not be overturned unless they are patently unreasonable. N.A.P.O. cites the following cases as authority for this proposition: *N.B. Liquor Corp. v. C.U.P.E., Loc. 963*, [1979] 2 S.C.R. 227, 25 N.B.R. (2d) 237, 51 A.P.R. 237, 24 N.R. 341, 79 C.L.L.C. 14,209 ("C.U.P.E."); *Douglas Aircraft Co. of Can. Ltd. v. McConnell*, [1980] 1 S.C.R. 245, 29 N.R. 109, 23 L.A.C. (2d) 143n, 99 D.L.R. (3d) 385, (sub nom. *Douglas Aircraft Co. v. U.A.W., Loc. 1967)* 79 C.L.L.C. 14,221 ; *A.U.P.E. v. Bd. of Governors of Olds College*, [1982] 1 S.C.R. 923 ; *O.P.S.E.U. v. Forer* (1985), 52 O.R. (2d) 705, 15 Admin. L.R. 145, 12 O.A.C. 1, 23 D.L.R. (4th) 97 ; *Ottawa (City) v. Ottawa Professional Firefighters' Assn.* (1987), 58 O.R. (2d) 685, 24 Admin. L.R. 213, 19 O.A.C. 197, 36 D.L.R. (4th) 609 ; *McCreary v. Greyhound Lines of Can. Ltd.* (1987), 87 C.L.L.C. 17,018, 78 N.R. 192, 8 C.H.R.R. D/4184, 38 D.L.R. (4th) 724 (Fed. C.A.) ; and *Canadian Pacific Ltd. v. Canadian Transport Commn.* (1987), 79 N.R. 13 (Fed. C.A.) ("Canadian Pacific").

31 With the exception of the *Canadian Pacific* case, supra, all these cases involved judicial review of decisions which were either protected by a privative clause or by a provision stating that no appeal lies therefrom. Where the legislator has clearly stated that the decision of an administrative tribunal is final and binding, Courts of original jurisdiction cannot interfere with such decisions unless the tribunal has committed an error which goes to its jurisdiction. Thus, this Court has decided in the *C.U.P.E.* case, supra, that judicial review cannot be completely excluded by statute and that Courts of original jurisdiction can always quash a decision if it is "so patently unreasonable that its construction cannot be rationally supported by the relevant legislation and demands intervention by the court upon review" (p. 237,

S.C.R.). Decisions which are so protected are, in that sense, entitled to a non-discretionary form of deference because the legislator intended them to be final and conclusive and, in turn, this intention arises out of the desire to leave the resolution of some issues in the hands of a specialized tribunal. In the *C.U.P.E.* case, Dickson J., as he then was, described the legislator's intention as follows, at pp. 235-36 (S.C.R.):

> Section 101 constitutes a clear statutory direction on the part of the Legislature that public sector labour matters be promptly and finally decided by the Board. Privative clauses of this type are typically found in labour relations legislation. The rationale for protection of a labour board's decisions within jurisdiction is straightforward and compelling. The labour board is a specialized tribunal which administers a comprehensive statute regulating labour relations. In the administration of that regime, a board is called upon not only to find facts and decide questions of law, but also to exercise its understanding of the body of jurisprudence that has developed around the collective bargaining system, as understood in Canada, and its labour relations sense acquired from accumulated experience in the area.

However, it is important to stress the fact that the decision of an administrative tribunal can only be entitled to such deference if the legislator has clearly expressed his intention to protect such decisions through the use of privative clauses or clauses which state that the decision is final and without appeal. As formulated, N.A.P.O.'s argument on curial deference must therefore be rejected because it fails to recognize the basic difference between appellate review and judicial review of decisions which do not fall within the jurisdiction of the lower tribunal.

32 Although s. 49(3) of the *National Transportation Act* provides that the appellant has full jurisdiction to hear and determine all matters whether of law or fact for the purposes of the *Railway Act* and of Part IV of the *National Transportation Act* , the appellant's decisions are subject to appeal, with leave, to the Federal Court of Appeal on questions of law or jurisdiction by virtue of s. 68(1), which reads as follows:

> 68. (1) An appeal lies from the Commission to the Federal Court of Appeal on a question of law or a question of jurisdiction on leave therefor being obtained from that Court on application made within one month after the making of the order, decision, rule or regulation sought to be appealed from or within such further time as a judge of that Court under special circumstances allows, and on notice to the parties and the Commission, and on hearing such of them as appear and desire to be heard.

It is trite to say that the jurisdiction of a Court on appeal is much broader than the jurisdiction of a Court on judicial review. In principle, a Court is entitled, on appeal, to disagree with the reasoning of the lower tribunal.

33 However, within the context of a statutory appeal from an administrative tribunal, additional consideration must be given to the principle of specialization of duties. Although an appeal tribunal has the right to disagree with the lower tribunal on issues which fall within the scope of the statutory appeal, curial deference should be given to the opinion of the lower tribunal on issues which fall squarely within its area of expertise. The *Canadian Pacific* case is an example of a situation where curial deference towards a decision of the Canadian Transport Commission involving the interpretation of a tariff was appropriate. The decision of the Canadian Transport Commission was appealed to a review committee and then to the Federal Court of Appeal. Urie J. held that the decision of the review committee must not be reversed unless it is unreasonable or clearly wrong, at pp. 16-17:

> On the appeal from that decision to this court, the appellant advanced essentially the same grounds and arguments which it had submitted to the R.T.C. As to the first ground, I am of the opinion that the R.T.C. correctly interpreted the two items from the tariff and since its view was confirmed by the Review Committee, that Committee did not commit an error in construction. No useful purpose would be served by my restating the reasons of the R.T.C. for interpreting the items as they did and I respectfully adopt them as my own. *This court should not interfere with an interpretation made by bodies having the expertise of the R.T.C. and the Review Committee in an area within their jurisdiction, unless their interpretation is not reasonable or is clearly wrong* . Neither situation prevails in this case.

(Emphasis added.) Although the very purpose of the review committee is to interpret the tariff, and although such questions of interpretation fall within the Review Committee's area of special expertise, it does not follow that its decisions can only be reviewed if they are unreasonable. However, the principle of specialization of duties justifies curial deference in such circumstances.

34 In this case, the respondent is challenging the appellant's decision on a question of law and jurisdiction involving the nature of interim decisions and the extent of the powers conferred on the appellant when it makes interim decisions. This question cannot be solved without an analysis of the procedural scheme created by the *Railway Act* and the *National Transportation Act* . It is a question of law which is clearly subject to appeal under s. 68(1) of the *National Transportation Act* . It is also a question of jurisdiction because it involves an inquiry into whether the appellant had the power to make a one-time credit order.

35 Except as regards the choice, amongst remedies available to the appellant, of the most appropriate remedy to achieve the goal of just and reasonable rates throughout the interim period, the decision impugned by the respondent is not a decision which falls within the appellant's area of special expertise and is therefore pursuant to s. 68(1), subject to review in accordance with the principles governing appeals. Indeed, the appellant was not created for the purpose of interpreting the *Railway Act* or the *National Transportation Act* but rather to ensure, amongst other duties, that telephone rates are always just and reasonable.

b) The power to regulate Bell Canada's revenues

36 The respondent argues that the appellant only has jurisdiction to regulate tolls and tariffs and that this power does not include the power to regulate its level of revenues or its return on equity.

37 The fixing of tolls and tariffs that are just and reasonable necessarily involves the regulation of the revenues of the regulated entity. This has been recognized by this Court interpreting provisions similar to s. 340(1) of the *Railway Act* which prescribe that "[a]ll tolls shall be just and reasonable". In *B.C. Electric Railway Co. v. Public Utilities Comm. of B.C.*, [1960] S.C.R. 837, 33 W.W.R. 97, 82 C.R.T.C. 32, 25 D.L.R. (2d) 689 , Locke J. said the following about para. 16(1)(b) of the *Public Utilities Act* , R.S.B.C. 1948, c. 277, which provided that in fixing a rate the Public Utility Commission of British Columbia should take into consideration the "fair and reasonable return upon the appraised value of the property of the public utility used ... to enable the public utility to furnish the service", at p. 848 (S.C.R.):

> I do not think it is possible to define what constitutes a fair return upon the property of utilities in a manner applicable to all cases or that it is expedient to attempt to do so. It is a continuing obligation that rests upon such a utility to provide what the Commission regards as adequate service in supplying not only electricity but transportation and gas, to maintain its properties in a satisfactory state to render adequate service and to provide extensions to these services when, in the opinion of the Commission, such are necessary. In coming to its conclusion as to what constituted a fair return to be allowed to the appellant *these matters as well as the undoubted fact that the earnings must be sufficient, if the company was to discharge these statutory duties, to enable it to pay reasonable dividends and attract capital, either by the sale of shares or securities, were of necessity considered* . Once that decision was made it was, in my opinion, the duty of the Commission imposed by the statute to approve rates which would enable the company to earn such a return or such lesser return as it might decide to ask.

(Emphasis added.) In *Northwestern Utilities Ltd. v. Edmonton*, [1929] S.C.R. 186, [1929] 2 D.L.R. 4 , Lamont J. described the relevant factors in the determination of what are just and reasonable rates as follows, at p. 190 (S.C.R.):

> In order to fix just and reasonable rates, which it was the duty of the Board to fix, the Board had to consider certain elements which must always be taken into account in fixing a rate which is fair and reasonable to the consumer and to the company. One of these is the rate base, by which is meant the amount which the Board considers the owner of the utility has invested in the enterprise and on which he is entitled to a fair return. Another is the percentage to be allowed as a fair return.

Such provisions require the administrative tribunal to balance the interests of the customers with the necessity of ensuring that the regulated entity is allowed to make sufficient revenues to finance the costs of the services it sells to the public.

38 Thus, it is trite to say that in fixing fair and reasonable tolls the appellant must take into consideration the level of revenues needed by the respondent. In fact, the respondent would be the first to complain if its financial situation was not taken into consideration when tolls are fixed. By so doing, the appellant regulates the respondent's revenues, albeit in a seemingly indirect manner. I would therefore dismiss this argument.

c) The power to revisit the period during which interim rates were in force

i) Introduction

39 As indicated above, the appellant has examined the period during which interim rates were in force, i.e. from January 1, 1985 to October 14, 1986, for the purpose of ascertaining whether these interim rates were in fact just and reasonable. Following a factual finding that these rates were not just and reasonable, the one-time credit order now contested before this Court was made in order to remedy this situation. Thus, the effect of Decision 86-17 was not retroactive in nature since it does not seek to establish rates to replace or be substituted to those which were charged during that period. The one-time credit order is, however, retrospective in the sense that its purpose is to remedy the imposition of rates approved in the past and found in the final analysis to be excessive. Thus, the question before this Court is whether the appellant has jurisdiction to make orders for the purpose of remedying the inappropriateness of rates which were approved by it in a previous interim decision.

40 This question involves a determination of whether rates approved by interim order are inherently contingent as well as provisional, or whether the statutory scheme established by the *Railway Act* and the *National Transportation Act* is so prospective in nature that it precluded such a retrospective review of interim rates approved by the appellant. Finally, it is also necessary to determine whether the appellant has jurisdiction to order the reimbursement of amounts which exceed the revenues actually collected as a direct result of the interim rates.

ii) The distinction between interim and final orders

41 The respondent argues that the *Railway Act* and the *National Transportation Act* establish a regulatory regime which is exclusively prospective in nature because all rates, whether interim or final, must be just and reasonable. Thus, if interim rates have been approved on the basis that they are just and reasonable, no excessive revenues can be earned by charging such rates; interim rates, by reason only of their approval by the appellant, are presumed to be just and reasonable until they are modified by a subsequent order. According to the respondent, interim orders are therefore orders made "for the time being" until a more permanent order is made.

42 In his dissenting reasons, Hugessen J. points out quite accurately that if interim orders are simply orders made "for the time being", it will be impossible to distinguish final orders from interim orders within the statutory scheme established by the *Railway Act* and the *National Transportation Act* since all final orders may be revised by the appellant of its own motion and at any time: s. 335(1) of the *Railway Act* and s. 52 of the *National Transportation Act* . It is therefore impossible to say that final orders made under these statutes are final in the sense that they may never be reconsidered. The on-going nature of the appellant's regulatory activities necessarily entails a continuous review of past decisions concerning tolls and tariffs. Thus, all orders, whether final or interim, would be orders "for the time being" within the statutory scheme established by the *Railway Act* and the *National Transportation Act* .

43 Both the appellant and Hugessen J. rely heavily on *Coseka Resources Ltd. v. Saratoga Processing Co.; Petrogas Processing Ltd. v. Pub. Utilities Bd.* (1981), 16 Alta. L.R. (2d) 60, 126 D.L.R. (3d) 705, 31 A.R. 541 (C.A.) ("*Coseka* ") for the proposition that interim decisions must be distinguished from final decisions in that they may be reviewed in a retrospective manner. This distinction is based on the fact that interim decisions are made subject to "further direction" as prescribed by s. 60(2) of the *National Transportation Act* which, for convenience, I cite again:

60. ...

(2) The Commission may, instead of making an order final in the first instance, make an interim order and *reserve further directions* either for an adjourned hearing of the matter or for further application.

(Emphasis added.) The statutory scheme analysed by the Alberta Court of Appeal in *Coseka* , supra, is substantially similar to though more clearly prospective than the statutory scheme established by the *Railway Act* and the *National Transportation Act* . Furthermore, s. 52(2) of the *Public Utilities Board Act* , R.S.A. 1970, c. 302, is identical in wording to s. 60(2) of the *National Transportation Act* . Laycraft J.A., as he then was, cited with approval by Hugessen J., wrote the following with respect to the possibility of revisiting the period during which interim rates were in force for the purpose of deciding whether those interim rates were in fact just and reasonable, at pp. 717-718 (D.L.R.):

In my view, to say that an interim order may not be replaced by a final order is to attribute virtually no additional powers to the Board from s. 52 beyond those already contained in either the *Gas Utilities Act* or the *Public Utilities Board Act* to make final orders. The Board is by other provisions of the statute empowered by order to fix rates either on application or on its own motion. *An interim order would be the same, and have the same effect, as a final order unless the 'further direction' which the statute contemplates includes the power to change the interim order. On that construction of the section the interim order would be a 'final' order in all but name* . The Board would need no further legislative authority to issue a further 'final' order since it may fix rates under s. 27 on its own motion without a further application. The provision for an interim order was intended to permit rates to be fixed subject to correction to be made when the hearing is subsequently completed.

It was urged during argument that s. 52(2) was merely intended to enable the Board to achieve 'rough justice' during the period of its operation until a final order is issued. However, the Board is required to fix 'just and reasonable rates' not 'roughly just and reasonable rates'. The words 'reserve for further direction', in my view, contemplate changes as soon as the Board is able to determine those just and reasonable rates.

(Emphasis added.)

44 I agree with Hugessen J. and with the reasons of Laycraft J.A. in *Coseka* where he made a careful review of previous cases. The statutory scheme established by the *Railway Act* and the *National Transportation Act* is such that one of the differences between interim and final orders must be that interim decisions may be reviewed and modified in a retrospective manner by a final decision. It is inherent in the nature of interim orders that their effect, as well as any discrepancy between the interim order and the final order, may be reviewed and remedied by the final order. I hasten to add that the words "further directions" do not have any magical, retrospective content. Under the *Railway Act* and the *National Transportation Act* , final orders are subject to "further [prospective] directions" as well. It is the interim nature of the order which makes it subject to further retrospective directions.

45 The importance of distinguishing final orders from interim orders is illustrated by the case of *City of Calgary v. Madison Natural Gas Co.* (1959), 19 D.L.R. (2d) 655 (Alta. C.A.) ("*Madison* "). In *Madison* , supra, the Public Utility Board (the "Board") was faced with an application by the City of Calgary for the reimbursement of amounts earned in excess of the rates of the rates of return allowed in orders 34 and 41 for the sale of natural gas. The Board had allowed a rate of return of 7 per cent but, due to its lack of useful information to predict the effect of rates on the actual financial performance of the regulated entity, the rates per volume fixed by the Board actually yielded greater profits than anticipated. The Board refused to grant the demands made in the application because it felt it had no jurisdiction to revisit periods during which rates approved in a final decision were in force. This decision was confirmed by the Court of Appeal on the basis that, contrary to arguments made by the City of Calgary, orders 34 and 41 were final orders not governed by s. 35*a* (3) of the *Natural Gas Utilities Act* , S.A. 1944, c. 4, which read as follows:

35a ...

> (3) The Board is hereby authorized, empowered and directed, on the final hearing, to give consideration to the effect of the operation of such interim or temporary order and in the final order to make, allow or provide for such adjustments, allowances or other factors, as to the Board may seem just and reasonable.

Order 34 provided that the price was set at 9 cents per mcf and that "if it should turn out that there is a surplus, it can be dealt with when the time arrives" which led to the argument that this order was in fact an interim order. Johnson J.A. dismissed this argument in the following terms, at pp. 662-663:

> It is the submission of the appellants that O. 34 and O. 41 are interim or temporary orders and the Board can now deal with these surpluses in accordance with s-s (3). As I have mentioned, orders fixing interim prices were made while the Board was hearing the application and considering its report. These, of course, were superseded by the order now under consideration. Orders 34 and 41 are, of course, not final orders in the sense that judgments are final. The Act contemplates that subsequent applications will be made to change the price fixed by these orders. They are nonetheless final so far as each application is concerned.

It is useful to note that the respondent relies heavily on the *Madison* case for the proposition that a regulated entity cannot be forced to disgorge profits legally earned by charging rates approved by the relevant regulatory authority on the basis that they are just and reasonable. Since the City of Calgary sought to obtain the reimbursement of profits earned by charging rates approved by final order, this case does not support the respondent's position.

46 A consideration of the nature of interim orders and the circumstances under which they are granted further explains and justifies their being, unlike final decisions, subject to retrospective review and remedial orders. The appellant may make a wide variety of interim orders dealing with hearings, notices and, in general, all matters concerning the administration of proceedings before the appellant. Such orders are obviously interim in nature. However, this is less obvious when an interim order deals with a matter which is to be dealt with in the final decision, as was the case with the interim rate increase ordered in Decision 84-28. If interim rate increases are awarded on the basis of the same criteria as those applied in the final decision, the interim decision would serve as a preliminary decision on the merits as far as the rate increase is concerned. This, however, is not the purpose of interim rate orders.

47 Traditionally, such interim rate orders dealing in an interlocutory manner with issues which remain to be decided in a final decision are granted for the purpose of relieving the applicant from the deleterious effects caused by the length of the proceedings. Such decisions are made in an expeditious manner on the basis of evidence which would often be insufficient for the purposes of the final decision. The fact that an order does not make any decision on the merits of an issue to be settled in a final decision, and the fact that its purpose is to provide temporary relief against the deleterious effects of the duration of the proceedings, are essential characteristics of an interim rate order.

48 In Decision 84-28, the appellant granted the respondent an interim rate increase on the basis of the following criteria which, for convenience, I cite again, at p. 9:

> The Commission considers that, as a rule, general rate increases should only be granted following the full public process contemplated by Part III of its Telecommunications Rules of Procedure. In the absence of such a process, general rate increases should not in the Commission's view be granted, even on an interim basis, except where special circumstances can be demonstrated. Such circumstances would include lengthy delays in dealing with an application that could result in a serious deterioration in the financial condition of an applicant absent a general interim increase.

Decision 84-28 was truly an interim decision since it did not seek to decide in a preliminary manner an issue which would be dealt with in the final decision. Instead, the appellant granted the interim rate increase on the basis that such an increase was necessary in order to prevent the respondent from having serious financial difficulties.

49 Furthermore, the appellant consistently reiterated throughout the procedures which led to Decision 86-17 its intention to review the rates charged for the test year 1985 and up to the date of the final decision. Holding that the

interim rates in force during that period cannot be reviewed would not only be contrary to the nature of interim orders, it would also frustrate and subvert the appellant's order approving interim rates.

50 It is true, as the respondent argues, that all telephone rates approved by the appellant must be just and reasonable whether these rates are approved by interim or final order; no other conclusion can be derived from s. 340(1) of the *Railway Act* . However, interim rates must be just and reasonable on the basis of the evidence filed by the applicant at the hearing or otherwise available for the interim decision. It would be useless to order a final hearing if the appellant was bound by the evidence filed at the interim hearing. Furthermore, the interim rate increase was granted on the basis that the length of the proceedings could cause a serious deterioration in the financial condition of the respondent. Only once such an emergency situation was found to exist did the appellant ask itself what rate increase would be just and reasonable on the basis of the available evidence and for the purpose of preventing such a financial deterioration. The inherent differences between a decision made on an interim basis and a decision made on a final basis clearly justify the power to revisit the period during which interim rates were in force.

51 The respondent argues that the power to revisit the period during which interim rates were in force cannot exist within the statutory scheme established by the *Railway Act* and the *National Transportation Act* because these statutes do not grant such a power explicitly, unlike s. 64 of the *National Energy Board Act* , R.S.C. 1985, c. N-7. The powers of any administrative tribunal must of course be stated in its enabling statute, but they may also exist by necessary implication from the wording of the act, its structure and its purpose. Although Courts must refrain from unduly broadening the powers of such regulatory authorities through judicial law-making, they must also avoid sterilizing these powers through overly technical interpretations of enabling statutes. I have found that, within the statutory scheme established by the *Railway Act* and the *National Transportation Act* , the power to make interim orders necessarily implies the power to revisit the period during which interim rates were in force. The fact that this power is provided explicitly in other statutes cannot modify this conclusion based as it is on the interpretation of these two statutes as a whole.

52 I am bolstered in my opinion by the fact that the regulatory scheme established by the *Railway Act* and the *National Transportation Act* gives the appellant very broad procedural powers for the purpose of ensuring that telephone rates and tariffs are, at all times, just and reasonable. Within this regulatory framework, the power to make appropriate orders for the purpose of remedying interim rates which are not just and reasonable is a necessary adjunct to the power to make interim orders.

53 It is interesting to note that, in the context of statutory schemes which did not provide any power to set interim rates, the United States Supreme Court has held that regulatory agencies have both the power to impose interim rates and the power to make reimbursement orders where the interim rates are found to be excessive in the final order: see *U.S. v. Fulton* (1986), 475 U.S. 657 , at pp. 669-671; *Re Trans Alaska Pipeline Rate Cases* (1978), 436 U.S. 631, where Brennan J. wrote the following comments, at pp. 654-656:

> Finally, petitioners contend that the Commission has no power to subject them to an obligation to account for and refund amounts collected under the interim rates in effect during the suspension period and the initial rates which would become effective at the end of such a period ... In response, we note first that we have already recognized in *Chessie* that the Commission does have powers 'ancillary' to its suspension power which do not depend on an express statutory grant of authority. We had no occasion in *Chessie* to consider what the full range of such powers might be, but we did indicate that the touchstone of ancillary power was a 'direc(t) relat(ionship)' between the power asserted and the Commission's 'mandate to assess the reasonableness of ... rates and to suspend them pending investigation if there is a question as to their legality.' 426 U.S., at 514.
>
> Thus, here as in *Chessie* , the Commission's refund conditions are a 'legitimate, reasonable, and direct adjunct to the Commission's explicit statutory power to suspend rates pending investigation,' in that they allow the Commission, in exercising its suspension power, to pursue 'a more measured course' and to 'offe[r] an alternative tailored far more precisely to the particular circumstances' of these cases. Since, again as in *Chessie* , the measured course adopted here is necessary to strike a proper balance between the interests of carriers and the public, we think the

> *Interstate Commerce Act* should be construed to confer on the Commission the authority to enter on this course unless language in the Act plainly requires a contrary result.

This approach to the interpretation of statutes conferring regulatory authority over rates and tariffs is only the expression of the wider rule that the Court must not stifle the legislator's intention by reason only of the fact that a power has not been explicitly provided for.

54 The appellant has also argued that the power to "vary" a previous decision, whether interim or final, found in s. 66 of the *National Transportation Act* , includes the power to vary these decisions in a retroactive manner. Given my conclusion based on the inherent nature of interim orders, it is unnecessary for me to deal with this argument.

iii) The relevance of the distinction between positive approval and negative disallowance schemes of rate regulation

55 Much was said in argument about the difference between positive approval schemes and negative disallowance schemes, with respect to the power to act retrospectively. The first category includes schemes which provide that the administrative agency is the only body having statutory authority to approve or fix tolls payable to utility companies; these schemes generally stipulate that tolls shall be "just and reasonable" and that the administrative agency has the power to review these tolls on a proprio motu basis, or upon application by an interested party. The second category includes schemes which grant utility companies the right to fix tolls as they wish, but also grant users the right to complain before an administrative agency which has the power to vary those tolls if it finds that they are not "just and reasonable". It has generally been found that negative disallowance schemes provide the power to make orders which are retroactive to the date of the application, by the ratepayer who claims that the rates are not "just and reasonable". On the other hand, positive approval schemes have been found to be exclusively prospective in nature and not to allow orders applicable to periods prior to the final decision itself. A full discussion of this issue was made by Estey J. in *Nova v. Amoco Can. Petroleum Co.*, [1981] 2 S.C.R. 437 at 450-451, [1981] 6 W.W.R. 391, 38 N.R. 381, 128 D.L.R. (3d) 1, 32 A.R. 384 , and I do not propose to repeat or to criticize what was said in that case with respect to the power to review rates approved by a previous final order. I am of the opinion that the regulatory scheme established by the *Railway Act* and the *National Transportation Act* is a positive approval scheme inasmuch as the respondent's rates are subject to approval by the appellant. However, the *Nova* case, supra, only dealt with the power to review rates approved in a previous final decision and, as I have said before, entirely different considerations apply when interim rates are reviewed.

56 It has often been said that the power to review its own previous final decision on the fairness and the reasonableness of rates would threaten the stability of the regulated entity's financial situation. In *R. v. Bd. of Commrs. of Public Utilities (N.B.); Ex parte Moncton Utility Gas Ltd.* (1966), 60 D.L.R. (2d) 703 , Ritchie J.A., as he then was, wrote the following comments on this issue, at p. 729:

> The distributor contends that in the absence of any express limitation or restriction or an express provision as to the effective date of any order made by the board, the jurisdiction conferred on the board by the Legislature includes jurisdiction to make orders with retrospective effect. Reliance is placed on *Bakery and Confectionery Workers International Union of America, Local 468 v. Salmi, White Lunch Ltd. v. Labour Relations Board of British Columbia*, 56 D.L.R. (2d) 193, [1966] S.C.R. 282, 55 W.W.R. 129 which it is contended must be applied when interpreting s. 6(1) of the Act.
>
> The clear object of the Act is to ensure stability in the operation of public utilities and the maintenance of just, reasonable and non-discriminatory rates. That object would be defeated if the board having, on November 14, 1962, made an order fixing the rates to be paid by the distributor for natural gas purchased from the producer, reduced those rates on February 19, 1966, more than three years later, and directed that the reduced rates be effective as from January 1, 1962, or as from any other date prior to February 19, 1966.

and further at p. 732:

> In no section of the Act do I find any wording indicating an intention on the part of the Legislature to confer on the board authority to make orders fixing rates with retrospective effect or any language requiring a construction that such authority has been bestowed on the board. To so interpret s. 6(1) would render insecure the position of not only every public utility carrying on business in the Province but also the position of every customer of such public utility.

However, Ritchie J.A.'s comments deal with the *Public Utilities Act* , R.S.N.B. 1952, c. 186, which did not provide the Board with any power to make interim orders. I readily agree that Ritchie J.A.'s concerns about the financial stability of utility companies are valid when one is faced with the argument that a Board has the power to revisit its own previous final decisions. Since no time limit could be placed on the period which could be revisited, any power to revisit previous final decisions would have to be explicitly provided in the enabling statute. Furthermore, even if final orders are "for the time being", it does not necessarily follow that they must be stripped of all their finality through the judicial recognition of a power to revisit a period during which final rates were in force.

57 However, there should be no concern over the financial stability of regulated utility companies where one deals with the power to revisit interim rates. The very purpose of interim rates is to allay the prospect of financial instability which can be caused by the duration of proceedings before a regulatory tribunal. In fact, in this case, the respondent asked for and was granted interim rate increases on the basis of serious apprehended financial difficulties. The added flexibility provided by the power to make interim orders is meant to foster financial stability throughout the regulatory process. The power to revisit the period during which interim rates were in force is a necessary corollary of this power, without which interim orders made in emergency situations may cause irreparable harm and subvert the fundamental purpose of ensuring that rates are just and reasonable.

58 Even though Parliament has decided to adopt a positive approval regulatory scheme for the regulation of telephone rates, the added flexibility provided by the power to make interim orders indicates that the appellant is empowered to make orders as of the date at which the initial application was made or as of the date the appellant initiated the proceedings of its own motion. The underlying theory behind the rule that a positive approval scheme only gives jurisdiction to make prospective orders is that the rates are presumed to be just and reasonable until they are modified because they have been approved by the regulatory authority on the basis that they were indeed just and reasonable. However, the power to make interim orders necessarily implies the power to modify in its entirety the rate structure previously established by final order. As a result, it cannot be said that the rate review process begins at the date of the final hearing; instead, the rate review begins when the appellant sets interim rates pending a final decision on the merits. As was stated in obiter in *Re Eurocan Pulp & Paper Co. and B.C. Energy Commn.* (1978), 87 D.L.R. (3d) 727 (B.C.C.A.) , with respect to a similar though not identical legislative scheme, the power to make interim orders effectively implies the power to make orders effective from the date of the beginning of the proceedings. In turn, this power must comprise the power to make appropriate orders for the purpose of remedying any discrepancy between the rate of return yielded by the interim rates and the rate of return allowed in the final decision for the period during which they are in effect, so as to achieve just and reasonable rates throughout that period.

iv) The power to make a one-time credit order

59 Once it is decided, as I have, that the appellant does have the power to revisit the period during which interim rates were in force for the purpose of ascertaining whether they were just and reasonable, it would be absurd to hold that it has no power to make a remedial order where, in fact, these rates were not just and reasonable. I also agree with Hugessen J. that s. 340(5) of the *Railway Act* provides a sufficient statutory basis for the power to make remedial orders, including an order to give a one-time credit to certain classes of customers.

60 C.N.C.P. Telecommunications argues that the one-time credit order should be limited to the amount of revenues actually derived as a direct result of the 2 per cent interim rate increase and that these excess revenues should be refunded to the actual customers who paid them. The presumption behind this argument is that the portion of the interim rates corresponding to the final rates in force prior to the beginning of the proceedings cannot be held to be unjust or

unreasonable until a final decision is rendered. As I have held that the appellant has jurisdiction to review the fairness and the reasonableness of these interim rates in their entirety because the rate-review process starts as of the date of the beginning of the proceedings, this argument must be dismissed.

61 Finally, it is true that the one-time credit ordered by the appellant will not necessarily benefit the customers who were actually billed excessive rates. However, once it is found that the appellant does have the power to make a remedial order, the nature and extent of this order remain within its jurisdiction in the absence of any specific statutory provision on this issue. The appellant admits that the use of a one-time credit is not the perfect way of reimbursing excess revenues. However, in view of the cost and the complexity of finding who actually paid excessive rates, where these persons reside, and of quantifying the amount of excessive payments made by each, and having regard to the appellant's broad jurisdiction in weighing the many factors involved in apportioning respondent's revenue requirement amongst its several classes of customers to determine just and reasonable rates, the appellant's decision was eminently reasonable and I agree with Hugessen J. that it should not be overturned.

VI — Conclusion

62 In my opinion, the appellant had jurisdiction to review the interim rates in force prior to Decision 86-17 for the purpose of ascertaining whether they were just and reasonable, had jurisdiction to order the respondent to grant the one-time credit described in Decision 86-17, and has committed no error in so doing.

63 I would allow the appeal and confirm the appellant's decision, with costs in all Courts.

Appeal allowed. Decision of Canadian Radio-Television Telecommunications Commission affirmed.

End of Document

DARLINGTON REFURBISHMENT PROGRAM OVERVIEW

1.0 PROGRAM SUMMARY

The Darlington Refurbishment Program (the “Program” or “DRP”) is a multi-year, multi-phase mega-project that will enable the Darlington Generating Station (“Darlington”) to continue safe and reliable operation until approximately 2055. The Program includes the replacement of life-limiting critical components, the completion of upgrades to meet applicable regulatory requirements, and the rehabilitation of components at Darlington’s four units. The Program is comprised of individual projects of various scales and sizes that will be executed during multi-year outages.

In this application, OPG provides an update on the progress of the DRP and evidence to support its request for approval of in-service additions through 2021, including the in-service additions related to Unit 2 refurbishment. More specifically, OPG’s pre-filed evidence demonstrates that:

- OPG has successfully performed the detailed planning that is necessary to determine Program scope and to establish high-confidence schedule (“schedule”) and cost estimates for safely completing the Unit 2 refurbishment by February 2020 and refurbishment of the other three units thereafter; and
- OPG has in place the resources, organization and processes necessary to execute the refurbishment of Unit 2, and the Program in its entirety, safely, on time, on budget, and to the required quality level.

As part of the work completed during the Definition Phase of the Program, all major contracts required to execute the scope of the DRP have been awarded. The detailed planning conducted by OPG and its contractors during the Definition Phase has enabled the development of a four-unit budget and schedule for the successful execution of the DRP. Critical to OPG’s planning efforts during this phase have been the construction of a full scale reactor mock-up and other training facilities which have been brought into service in this phase, as well as the Retube and Feeder Replacement tooling development and testing in the mock-up. Equally important has been the completion of the Unit 2 detailed engineering for each design modification package for all committed scope that is part of the DRP. Based upon this work, OPG prepared a detailed four-unit budget and schedule (the “Release Quality Estimate” or “RQE”), which was finalized in November 2015 (as discussed in Ex. D2-2-8).

Refurbishment of all four Darlington units will take place over a total span of 112 months (October 2016 to February 2026), including 40 months for Unit 2 from October 2016 to February 2020. Based on the significant effort that went into developing the RQE, which was approved by OPG’s Board of Directors on November 13, 2015, OPG has a high level of confidence in the DRP cost estimate of $12.8B, which includes contingency, capitalized interest and escalation. The RQE establishes a four-unit, program-level control budget that serves as the baseline against which the success of the DRP will be measured. Subsequent to receiving approval from OPG’s Board of Directors, the RQE was provided to the Minister of Energy, who announced the Province’s endorsement of the DRP on January 11, 2016.[1]

A simplified breakdown showing the Program components included in RQE and their budget is provided in Chart 1, below, followed by brief descriptions of the listed components. Life to date expenditures (to the end of 2015) are $2.2B, inclusive of interest and escalation.

[1] See: https://news.ontario.ca/mei/en/2016/01/ontario-moving-forward-with-nuclear-refurbishment-at-darlington-and-pursuing-continued-operations-at.html.

Chart 1

Simplified Breakdown of Total DRP Release Quality Estimate[2]

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**

Major Work Bundles are logical groupings of work scope, each consisting of a number of individual projects, defined by OPG for purposes of effectively contracting work to outside contractors and assigning project management accountabilities. The work to be undertaken through the major work bundles consists of the replacement and rehabilitation of components, inspections and the completion of upgrades directly related to unit refurbishment. The major work bundles are (1) Retube and Feeder Replacement ("RFR"), (2) Turbines, Generators and Auxiliaries ("Turbine Generator"), (3) Fuel Handling and Defueling, (4) Steam Generators, and (5) Balance of Plant.

Safety Improvement Opportunities ("SIO") are initiatives which OPG committed to in the Environmental Assessment ("EA") for the DRP, primarily to address beyond-design basis or four-unit events. The need for this work was established through the EA, which was filed with the Canadian Nuclear Safety Commission ("CNSC"). To meet required in-service dates, OPG commenced execution of SIO work early in the Definition Phase of the Program. The SIO are useful to OPG's current and future nuclear operations independent of whether the DRP is completed.

[2] The vast majority of these amounts are capital, but included in these amounts are some amounts (e.g. removal costs) that are expensed as OM&A. OM&A costs associated with the DRP are set out in Ex. F2-7-1.

Facilities and Infrastructure Projects ("F&IP") are projects that do not involve the refurbishment of units but which are necessary to enable execution of the unit refurbishments. A number of the F&IP involve upgrades to Darlington site infrastructure to ensure it can effectively support continued operations for 30 or more years. Other F&IP involve facilities that are needed to support DRP activities during the life of the Program. To meet required in-service dates, OPG commenced the F&IP work early in the Definition Phase of the Program. The F&IP are expected to remain useful to OPG's current and future nuclear operations independent of whether the DRP is completed.

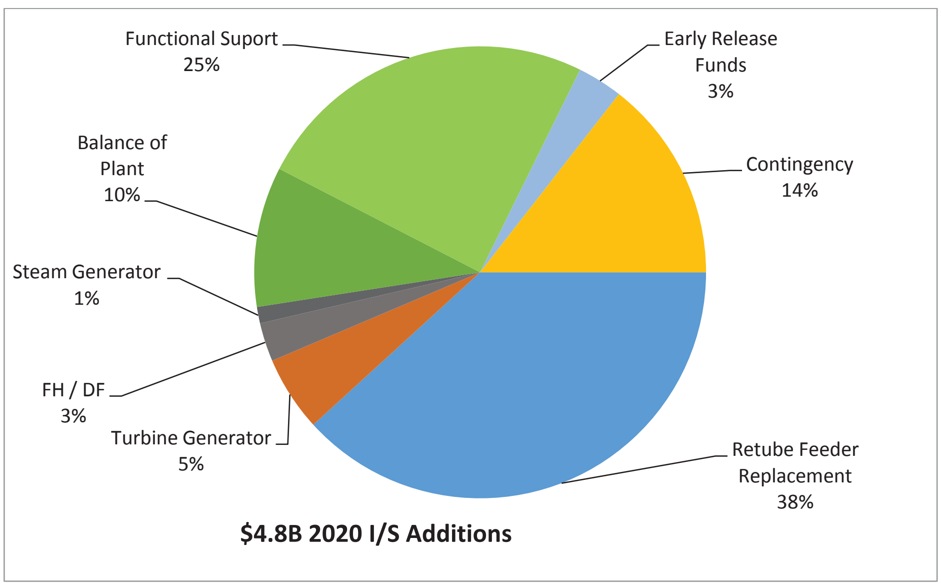
OPG Functional Support refers to work carried out by groups (referred to as "Functions") within OPG's DRP organization. The Functions provide a broad range of support that is critical for the success of the major work bundles and the Program as a whole, including oversight, coordination and integration among the various contractors and ongoing station operations. The largest of the groups, the Operations and Maintenance Function, is distinct from the others because it is both a functional and execution organization in that it provides functional support to the major work bundles and also directly carries out work at the station, particularly for the purpose of ensuring that refurbishment activities do not adversely impact Darlington's other operating units. It is largely through the Functions that OPG performs its vital role as the Program owner, with overall responsibility for Program management, deliverables, costs and schedule, as well as full integration with the operating units in order to comply with all CNSC regulations and safe work practices, including permits and work control, radiation protection, chemistry and environmental controls.

The remaining Program components consist of: (i) *Early Release Funds*, which are costs incurred during the Preliminary Planning Phase, such as with respect to EA and CNSC approvals work, that cannot be attributed to particular major work bundles or Functions; (ii) *Contingency*, which is an element of the cost estimate that is allocated to manage uncertainty and risk throughout the life of the Program, and which is expected to be spent based on OPG's in-depth assessment of the DRP risks and uncertainties that cannot be avoided or fully mitigated; and (iii) *Interest and Escalation*, which are included in the RQE to reflect costs associated with the passage of time during the life of the Program.

As noted above, the total four-unit budget to refurbish the four Darlington units is $12.8B. Within the 2017-2021 period, all of the F&IP and SIO will be placed in service and the Unit 2 refurbishment will be completed and placed in service. For the purpose of OPG's request for approval of in-service additions, $4,800.2M is forecast to come into service in 2020 for the Unit 2 refurbishment. A simplified breakdown showing the components of the Unit 2 amount is provided in Figure 1, below. While actual costs for particular components shown in Figure 1 may ultimately be higher or lower than forecast, OPG will complete the Unit 2 refurbishment within the total envelope budgeted for Unit 2 and OPG's performance with respect to cost should be considered on this basis.

Figure 1

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



OPG plans to issue annual status reports to the public for the duration of the Program. This reporting will include a range of measures, including construction completion, cost performance, schedule performance and safety performance, and is described in greater detail in section 7 of Ex. D2-2-9.

[3] Interest and escalation for in-service amounts are included in major work bundle costs.

2.0 APPROVALS SOUGHT

In the current application, OPG seeks the following OEB approvals for the DRP:

- In-service additions to rate base of: (i) $350.4M in the 2016 Bridge Year; and (ii) for the test period, $374.4M 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 $743.1M related to Unit Refurbishment Early In-Service Projects[4], 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
- 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).

OPG also seeks recovery of the contribution of the DRP to the Capacity Refurbishment Variance Account ("CRVA") 2015 balance, as discussed in Ex. H1-1-1.

3.0 EVIDENCE ROADMAP

To understand the rationale underlying the evidence roadmap set out below, it is important to understand that OPG has approached the DRP in a manner that is consistent with generally accepted methods for planning and implementing mega-projects. This process of planning and implementing the DRP provides the broad framework for presentation of this evidence.

More particularly, given the Program's complexity and in order to successfully complete the DRP on time and on budget, OPG must have in place a number of elements that are essential for Program development, execution and completion. This includes appropriate structure, both with respect to OPG's contractual relationships as well as organizationally, to ensure the appropriate allocation of risk and cost responsibility and an effective and

[4] See section 2.2 of Ex. D2-2-10 for more information on Unit Refurbishment Early In-Service Projects.

functioning working relationship between OPG as Program owner and its contractors. Moreover, OPG must undertake rigorous planning to ensure proper scope and corresponding cost and schedule. However, this is not an end in itself. OPG must also require its contractors to execute the major work bundles in an efficient and cost effective manner and must conduct itself likewise in its capacity as owner. Furthermore, while executing the four-unit refurbishment, OPG must comply with all CNSC regulatory requirements. OPG must also comply with provincial requirements for nuclear refurbishment as set out in the Long Term Energy Plan ("LTEP").

The Program cannot be viewed through a single lens or by considering a single component. As a result, OPG's evidence is structured so as to enable the OEB to understand that OPG (i) has adopted the most appropriate contracting strategy; (ii) has established an effective organization that aligns with and supports that strategy; (iii) has through that organization and in conjunction with its contractors undertaken extensive planning to define the scope, plan the schedule and estimate the cost of the Program; and (iv) has an effective execution strategy to ensure safe completion of the Program on time and on budget. The evidence is organized as follows:

- Ex. D2-2-1 (Program Overview) provides a summary of the Program, the approvals sought, this evidence roadmap and a description of the relevant regulatory framework, including recent amendments to Ontario Regulation 53/05, the Province's Long-Term Energy Plan and the relevant requirements of the CNSC;
- Ex. D2-2-2 (Program Structure) describes OPG's overall commercial strategy for the DRP, which establishes OPG as the Program owner and defines OPG's relationships with its external contractors. In a project of the magnitude of the DRP, it is critical that the responsibilities and accountabilities for project risks and execution be clear. It is also important to ensure alignment between the commercial/contracting strategies and the owner's organizational structure. This schedule describes how OPG has structured itself as the Program owner as well as the management system structures used by OPG to exercise its role as owner;
- Ex. D2-2-3 (Major Work Bundle Structure and Contracts) describes how OPG has structured the major work bundles, as well as the contracting approaches that OPG

has used for each of the major work bundles and the SIO and F&IP projects. The contracting models employed by OPG and the specific contract terms, such as with respect to pricing, will play a significant role in determining how the work will be performed and the overall success of the Program;

- Ex. D2-2-4 to Ex. D2-2-8 (Program Planning, Program Scope, Program Schedule, Contingency, and Cost) are all related directly to the development and approval of the RQE. Program planning concerns the significant investment in planning made by OPG during the Definition Phase to establish detailed scope, schedule and cost estimates, thereby minimizing the risk of scope creep, schedule delays and resulting increases in cost. OPG's approaches to identifying, defining and developing the Program scope, schedules, contingency amounts and cost estimates are considered in greater detail in these schedules;
- Ex. D2-2-9 (Program Execution) focuses on how OPG will manage the Program during execution, including the methods by which OPG as Program owner will manage circumstances that affect scope, schedule, cost and quality during refurbishment execution. In particular, this schedule considers the key activities to be carried out by certain OPG functional support groups during execution, as well as other key controlling activities all of which will enable OPG to effectively track progress and manage execution risk; and
- Ex. D2-2-10 (In-Service Amounts) describes the capital in-service additions, including for Unit 2 refurbishment, unit refurbishment early in-service projects, SIO and F&IP projects, as well as applicable variance analysis.

A detailed breakdown of the DRP evidence structure is included in Attachment 1.

OPG has also engaged independent experts to review and verify key aspects of the Program. The following independent expert reviews are provided in support of the evidence:

- KPMG review of risk management and contingency development process (Ex. D2-2-7, Attachment 1);
- KPMG review of the governance and processes to develop the RQE (Ex. D2-2-8, Attachment 2);

- Modus Strategic Solutions Canada Company and Burns & McDonnell Canada Ltd. Review of the RQE development process (Ex. D2-2-8, Attachment 3); and
- an expert panel, comprised of four individuals with retube and feeder replacement experience, review of the cost estimate for retube and feeder replacement (Ex. D2-2-8, Attachment 4).

In addition, two independent experts have been engaged to give evidence as follows:

- Concentric Energy Advisors, Inc. to provide an independent, updated assessment of their report filed in EB-2013-0321 of the commercial strategies developed for the RFR work package (Ex. D2-2-11, Attachment 1); and
- Pegasus Global Holdings, Inc. to provide an independent and objective assessment of the degree to which OPG's plan and approach to execution of the Program are consistent with the way other megaprojects and mega programs of comparable magnitude, scale and complexity have been carried out (Ex. D2-2-11, Attachment 3).

4.0 REGULATORY FRAMEWORK

4.1 Amendments to O. Reg. 53/05

On January 1, 2016, Ontario Regulation 53/05, *Payments Under Section 78.1 of the Ontario Energy Board Act* (O. Reg. 53/05) was amended to include additional provisions that deal with nuclear refurbishment costs and to define the scope of the OEB's jurisdiction in considering this application. In relation to the DRP, the amendments concern the following key aspects:

- The need for the DRP has been established by the regulation. As set out in the regulation, in setting nuclear payment amounts during the period from January 1, 2017 to the end of the DRP, the OEB shall accept the need for the DRP in light of the Ministry of Energy's 2013 LTEP and the related policy of the Minister endorsing the need for nuclear refurbishment.[5]

[5] O. Reg. 53/05, s. 6(2), para. 12(v).

- If the OEB is satisfied that costs of the DRP were prudently incurred and financial commitments were prudently made, the OEB must ensure that OPG recovers its capital and non-capital costs and firm financial commitments incurred for the DRP.[6]
- The OEB must permit OPG to establish a rate smoothing deferral account for the DRP.[7]
- In setting payment amounts for the deferral period (i.e. from January 1, 2017 to the end of the DRP), the OEB must determine, on a five year basis for the first ten years of the deferral period, and thereafter on such periodic basis as the OEB determines, the portion of the approved nuclear revenue requirement for each year that is to be deferred for purposes of making more stable the year-over-year changes in the nuclear payment amount.[8] OPG's rate smoothing proposal is discussed in Ex. A1-3-3.

4.2 Long Term Energy Plan

As stated by the Minister of Energy in Ontario's LTEP: "[t]he government is committed to nuclear power. It will continue to be the backbone of our electricity system, supplying about half of Ontario's electricity generation."[9] The Minister further stated in the LTEP:

> The government will ensure a reliable supply of electricity by proceeding with the refurbishment of the province's existing nuclear fleet taking into account future demand levels. Refurbishment received strong, province-wide support during the 2013 LTEP consultation process. The merits of refurbishment are clear:
>
> - Refurbished nuclear is the most cost-effective generation available to Ontario for meeting base load requirements.
> - Existing nuclear generating stations are located in supportive communities, and have access to high-voltage transmission.
> - Nuclear generation produces no greenhouse gas emissions.[10]

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[6] O. Reg. 53/05, s. 6(2), para. 4.
[7] O. Reg. 53/05, s. 5.5.
[8] O. Reg. 53/05, s. 6(2), paras. 12(i) and (ii).
[9] Government of Ontario, *Achieving Balance – Ontario's Long Term Energy Plan*, December 2013, p. 30.
[10] LTEP, page 29.

The LTEP sets out a number of principles with respect to the nuclear refurbishment process.[11] As highlighted in Attachment 2 below, OPG's plans for the DRP include a number of specific elements that align with each of these principles, which are as follows:

- minimize the commercial risk on the part of ratepayers and government;
- mitigate reliability risks by developing contingency plans that include alternative supply options if contract and other objectives are at risk of non-fulfillment;
- entrench appropriate and realistic off-ramps and scoping;
- require OPG to hold its contractors accountable to the nuclear refurbishment schedule and price;
- make site, project management, regulatory requirements and supply chain considerations, and cost and risk containment, the primary factors in developing the implementation plan; and
- take smaller initial steps to ensure there is opportunity to incorporate lessons learned from the refurbishment including collaboration by operators.

4.3 Minister's Support for DRP

In addition to issuing clear policy statements regarding the need for nuclear refurbishment, the Government of Ontario's support for the DRP has been affirmed through the Minister's announcement on January 11, 2016[12] endorsing OPG's plan to refurbish the four Darlington units.

4.4 CNSC Regulatory Framework

The CNSC exercises ongoing regulatory and licensing oversight over nuclear power plants in Canada. Continued operation of Darlington is largely dependent on the work that is required for long term safe operation.

The CNSC's regulatory expectations for proposed refurbishment and life extension projects at the time that OPG began to undertake the DRP required that OPG systematically identify and address all environmental and safety concerns, carry out an Integrated Safety Review

[11] LTEP, page 29.
[12] See footnote 1.

("ISR") and integrate them into a Global Assessment Report ("GAR") and an Integrated Implementation Plan ("IIP") in accordance with all CNSC regulations, including the requirements from Regulatory Document RD-360 (Life Extension of Nuclear Power Plants).[13] In December 2015, the CNSC ruled that OPG has completed an ISR, GAR and IIP as set out in Regulatory Document RD-360. Regulatory Document REGDOC-2.3.3 (Periodic Safety Reviews) has superseded Regulatory Document RD-360 relating to the life extension of nuclear plants. As part of Darlington's renewed Nuclear Power Reactor Operating Licence (discussed further below), in accordance with REGDOC-2.3.3 (Periodic Safety Reviews), the CNSC ruled that OPG must conduct a periodic safety review in support of OPG's next Nuclear Power Reactor Operating Licence application to confirm that the facility remains consistent with a set of modern codes and standards to demonstrate that the safety basis remains valid. CNSC's Regulatory Document REGDOC-2.3.3: Periodic Safety Reviews can found in Attachment 3, and Regulatory Document RD-360: Life Extension of Nuclear Power Plants can be found in Attachment 4. In addition, OPG is required to adhere to the requirements of the *Nuclear Safety and Control Act*, the *Canadian Environmental Assessment Act*, all associated regulations, and conditions under its operating license for Darlington.

The EA Screening Report for the DRP was submitted to the CNSC on December 1, 2011. The CNSC released its decision regarding the EA on March 14, 2013. The overall finding of the CNSC was that the DRP will not result in any significant adverse environmental effects given the proposed mitigation measures. As required by the OEB's Decision in EB-2013-0321, OPG is filing as part of this application updates of actual costs of the EA follow-up studies. These updates are provided in Attachment 5.

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[13] As set out in Regulatory Document RD-360, for a nuclear life extension project, the CNSC expects the licensee to demonstrate that the following objectives are met:

- The technical scope of the project is adequately determined through an IIP that takes into account the results of an EA and an ISR;
- Programs and processes that take into account the special considerations of the project are established; and
- The project is appropriately planned and executed.

(See: CNSC, RD-360: Life Extension of Nuclear Power Plants, Section 4.0.)

On December 23, 2015, the CNSC issued a renewed Darlington Nuclear Power Reactor Operating Licence effective January 1, 2016 until November 30, 2025. OPG's Nuclear Power Reactor Operating Licence application included the proposed refurbishment of Darlington. The CNSC concluded that OPG is qualified to carry on the proposed refurbishment project. The CNSC's Record of Proceedings, Including Reasons for Decisions was issued on March 2, 2016.[14]

[14] The CNSC Reasons for Decision can be found on the CNSC website as e-Doc 4920689 at: http://www.nuclearsafety.gc.ca/eng/the-commission/pdf/2015-11-02-CompleteDecision-OPG-Darlington-e-edoc4920689.pdf.

ATTACHMENTS

Attachment 1:	Detailed Breakdown of Evidence Structure
Attachment 2:	OPG Actions Taken/Planned in Alignment with LTEP Principles
Attachment 3:	Regulatory Document REGDOC-2.3.3: Periodic Safety Reviews
Attachment 4:	Regulatory Document RD-360: Life Extension of Nuclear Power Plants
Attachment 5:	Costs of Environmental Assessment Follow-up Studies

COMPARISON OF PRODUCTION FORECASTS
NUCLEAR

1.0 PURPOSE

This evidence presents period-over-period comparisons of nuclear production forecasts for 2013-2021 in support of the approval of OPG's nuclear production forecast for the test period.

2.0 OVERVIEW

Variances between actual and forecast production in any year or period-over-period variances are typically the result of OPG experiencing more or fewer forced outages ("FO") or derates, forced extensions to planned outages ("FEPO"), planned outage days or unbudgeted planned outages. Variances may also arise due to station consumption, grid losses and lake water temperature.

Period-over-period variances are presented in Ex. E2-1-2 Table 1 and are explained below.

PERIOD-OVER-PERIOD CHANGES – TEST YEARS

2017 Plan versus 2016 Budget

The nuclear production forecast for 2017 of 38.1 TWh is 8.7 TWh lower than the 2016 Budget of 46.8 TWh. The lower forecast production for 2017 relative to 2016 forecast production is primarily due to the following:

- There are 287 additional planned outage refurbishment days[1] for Darlington as Unit 2 refurbishment continues for the entire year.
- There are 182.4 additional planned outage days[1] for the combined nuclear fleet (additional 42.4 planned outage days for Darlington and additional 140 planned outage days for Pickering). The increase in planned outage days for Darlington is a result of a Single Fuel Channel Replacement on Unit 1, planned derates on Unit 3

[1] Darlington "planned outage refurbishment days" includes outage days for units out of service during refurbishment. "Planned outage days" excludes outage days for units out of service during refurbishment.

and 4 due to Unit 2 bulkhead installation, and a mini-outage to install Primary Heat Transport ("PHT") pump motors. The increase of planned outage days for Pickering reflects the additional scope required Pickering Extended Operations.

- There are 10.6 fewer equivalent days in the combined nuclear fleet Forced Loss Rate ("FLR"). While the forecast FLR is maintained year-over-year for Darlington (1.0 per cent) and Pickering (5.0 per cent), with additional planned outage days at both stations, this results in fewer equivalent FLR days.

2018 Plan versus 2017 Plan

The nuclear production forecast for 2018 of 38.5 TWh is 0.4 TWh higher than the 2017 Plan of 38.1 TWh. The higher forecast production for 2018 relative to 2017 forecast production is primarily due to the following:

- There are 20.9 fewer planned outage days for the combined nuclear fleet (10.1 fewer planned outage days for Darlington and 10.8 fewer planned outage days for Pickering). The reduction of planned outage days for Darlington is due to no Single Fuel Channel replacement and Planned Derates in 2018 versus 2017. The reduction in planned outage days for Pickering reflects the scope being undertaken in 2018 versus 2017 for Pickering Extended Operations.
- There is no change in the combined nuclear fleet FLR. With a total of 20.9 fewer planned outage days, this results in 0.6 additonal equivalent FLR days.
- There is no change in planned outage refurbishment days for Darlington as Unit 2 refurbishment continues for the entire year.

2019 Plan versus 2018 Plan

The nuclear production forecast for 2019 of 39.0 TWh is 0.6 TWh higher than the 2018 Plan of 38.5 TWh. The slightly higher forecast production for 2019 relative to 2018 forecast production is primarily due to the following:

- There are 32.9 fewer planned outage days for the combined nuclear fleet (19.2 fewer planned outage days for Darlington and 13.7 fewer planned outage days for Pickering). The reduction of planned outage days for Darlington is a result of one fewer mini-outage to install PHT pump motors, and reduced scope in the Unit 4

Most Negative Treatment: Recently added (treatment not yet designated)
Most Recent Recently added (treatment not yet designated): Ferme Jean Bélanger inc. c. Commission de protection du territoire agricole | 2018 QCCS 560, 2018 CarswellQue 1000, EYB 2018-290669 | (C.S. Qué., Feb 19, 2018)

2015 SCC 45, 2015 CSC 45
Supreme Court of Canada

ATCO Gas and Pipelines Ltd. v. Alberta (Utilities Commission)

2015 CarswellAlta 1745, 2015 CarswellAlta 1746, 2015 SCC 45, 2015 CSC 45, [2015] 3 S.C.R. 219, [2015] A.W.L.D. 3680, [2015] A.W.L.D. 3682, 20 Alta. L.R. (6th) 292, 21 C.C.P.B. (2nd) 1, 257 A.C.W.S. (3d) 728, 388 D.L.R. (4th) 515, 475 N.R. 83, 602 A.R. 1, 647 W.A.C. 1, J.E. 2015-1511

ATCO Gas and Pipelines Ltd. and ATCO Electric Ltd., Appellants and Alberta Utilities Commission and Office of the Utilities Consumer Advocate of Alberta, Respondents

McLachlin C.J.C., Abella, Rothstein, Cromwell, Moldaver, Karakatsanis, Gascon JJ.

Heard: December 3, 2014
Judgment: September 25, 2015
Docket: 35624

Proceedings: affirming *ATCO Utilities, Re* (2013), 7 C.C.P.B. (2nd) 171, 93 Alta. L.R. (5th) 234, (sub nom. *Atco Gas and Pipelines Ltd. v. Alberta Utilities Commission)* 584 W.A.C. 376, 556 A.R. 376, 2013 ABCA 310, 2013 CarswellAlta 1984, Frans Slatter J.A., Peter Costigan J.A., Peter Martin J.A. (Alta. C.A.); affirming *ATCO Utilities, Re* (2011), 2011 CarswellAlta 1646, Anne Michaud Chair, Bill Lyttle Member, Moin A. Yahya Member (Alta. U.C.)

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Subject: Corporate and Commercial; Public; Employment
Related Abridgment Classifications
Public law
IV Public utilities
IV.5 Regulatory boards
IV.5.b Regulation of rates
Public law
IV Public utilities
IV.5 Regulatory boards
IV.5.d Miscellaneous
Headnote
Public law --- Public utilities — Regulatory boards — Miscellaneous
Regulated companies applied to include their full pension costs in their revenue requirements — Companies argued that their pension policies were prudent, made in good faith by third party, and consistent with industry standards, and that they should be allowed to include all of their pension costs in their rates — Utilities commission denied companies permission to include certain pension costs in their estimates of revenue requirements — Commission found that evidence

did not support finding that awarding in every year annual cost of living adjustment (COLA) award of 100 per cent of consumer price index up to three per cent was acceptable standard practice — Companies appealed — Appeal was dismissed — Court of Appeal ruled that analytical framework selected by commission was not unreasonable — Two-stage analysis of determining if expenditures were prudently incurred and then setting of reasonable rates was not mandated — On record, it was open to commission to determine that only 50 per cent of COLA amounts should be included in rates — Reasons for decision explained adequately how commission came to that conclusion, and there was no basis for appellate intervention — Utility companies appealed — Appeal dismissed — Standard of review was reasonableness — Regulatory framework allowed commission to set just and reasonable tariffs for electric and gas utilities seeking recovery of their prudent costs and expenses but does not impose specific rate-setting methodology — Commission itself must decide upon specific test and methodology to employ — There is no obligation on commission to utilize particular prudence test methodology when reviewing costs on forecast basis — Utility bears onus of proving that tariff it proposes is just and reasonable — Both methodology commission used, and application of that methodology, were reasonable given nature of costs.

Public law --- Public utilities — Regulatory boards — Regulation of rates

Regulated companies applied to include their full pension costs in their revenue requirements — Companies argued that their pension policies were prudent, made in good faith by third party, and consistent with industry standards, and that they should be allowed to include all of their pension costs in their rates — Utilities commission denied companies permission to include certain pension costs in their estimates of revenue requirements — Commission found that evidence did not support finding that awarding in every year annual cost of living adjustment (COLA) award of 100 per cent of consumer price index up to three per cent was acceptable standard practice — Companies appealed — Appeal was dismissed — Court of Appeal ruled that analytical framework selected by commission was not unreasonable — Two-stage analysis of determining if expenditures were prudently incurred and then setting of reasonable rates was not mandated — On record, it was open to commission to determine that only 50 per cent of COLA amounts should be included in rates — Reasons for decision explained adequately how commission came to that conclusion, and there was no basis for appellate intervention — Utility companies appealed — Appeal dismissed — Regulatory framework allowed commission to set just and reasonable tariffs for electric and gas utilities seeking recovery of their prudent costs and expenses but does not impose specific rate-setting methodology — Commission itself must decide upon specific test and methodology to employ — There is no obligation on commission to utilize particular prudence test methodology when reviewing costs on forecast basis — There is no presumption of prudence — Utility bears onus of proving that tariff it proposes is just and reasonable — Both methodology commission used, and application of that methodology, were reasonable given nature of costs.

Droit autochtone --- Divers

Compagnies réglementées ont demandé à ce que l'ensemble des coûts relatifs au régime de retraite soient inclus dans les exigences se rapportant à leur revenu — Compagnies ont fait valoir que les politiques applicables à leur régime de retraite étaient prudentes, établies de bonne foi par une tierce partie et conformes aux normes de l'industrie et qu'elles devraient être autorisées à inclure l'ensemble des coûts relatifs au régime de retraite dans leurs tarifs — Commission des services publics a refusé d'autoriser les compagnies à inclure certains coûts relatifs au régime de retraite dans leurs estimations des recettes nécessaires — Commission a conclu que la preuve ne permettait pas de conclure que le recouvrement à chaque année de l'ajustement annuel au coût de la vie (AACV) à raison de 100 p. cent de l'indice des prix à la consommation jusqu'à un maximum de 3 p. cent constituait une pratique courante reconnue — Compagnies ont interjeté appel — Appel a été rejeté — Cour d'appel a décidé que le cadre d'analyse utilisé par la Commission n'était pas déraisonnable — Analyse en deux volets visant à déterminer si les dépenses avaient été prudemment encourues puis à établir des taux raisonnables n'était pas obligatoire — Au vu du dossier, il était loisible à la Commission de conclure que seulement 50 p. cent des montants relatifs à l'AACV devrait être inclus dans les taux — Motifs de cette décision expliquaient adéquatement la manière dont la Commission en était venu à cette conclusion et la Cour d'appel n'était pas justifiée d'intervenir — Compagnies ont formé un pourvoi — Pourvoi rejeté — Norme de contrôle applicable était celle de la décision raisonnable — Cadre réglementaire permettait à la Commission d'établir des tarifs justes et raisonnables pour les fournisseurs d'électricité et de gaz qui voulaient obtenir le recouvrement de leurs coûts et dépenses encourus de manière prudente, mais il n'imposait pas de méthodologie particulière pour l'établissement des tarifs — Il appartenait à la Commission de choisir quel test et quelle méthodologie employer — Commission n'était pas obligée d'utiliser une méthodologie particulière pour le test visant à déterminer la prudence lorsqu'elle révisait la prévision des coûts — Il revenait aux fournisseurs de démontrer que le tarif qu'ils proposaient était juste et raisonnable — Méthodologie utilisée par la Commission et la manière dont elle l'a appliquée étaient raisonnables compte tenu de la nature des coûts.

Droit public --- Services publics — Organismes de réglementation — Réglementation des tarifs

Compagnies réglementées ont demandé à ce que l'ensemble des coûts relatifs au régime de retraite soient inclus dans les exigences se rapportant à leur revenu — Compagnies ont fait valoir que les politiques applicables à leur régime de retraite étaient prudentes, établies de bonne foi par une tierce partie et conformes aux normes de l'industrie et qu'elles devraient être autorisées à inclure l'ensemble des coûts relatifs au régime de retraite dans leurs tarifs — Commission des services publics a refusé d'autoriser les compagnies à inclure certains coûts relatifs au régime de retraite dans leurs estimations des recettes nécessaires — Commission a conclu que la preuve ne permettait pas de conclure que le recouvrement à chaque année de l'ajustement annuel au coût de la vie (AACV) à raison de 100 p. cent de l'indice des prix à la consommation jusqu'à un maximum de 3 p. cent constituait une pratique courante reconnue — Compagnies ont interjeté appel — Appel a été rejeté — Cour d'appel a décidé que le cadre d'analyse utilisé par la Commission n'était pas déraisonnable — Analyse en deux volets visant à déterminer si les dépenses avaient été prudemment encourues puis à établir des taux raisonnables n'était pas obligatoire — Au vu du dossier, il était loisible à la Commission de conclure que seulement 50 p. cent des montants relatifs à l'AACV devrait être inclus dans les taux — Motifs de cette décision expliquaient adéquatement la manière dont la Commission en était venu à cette conclusion et la Cour d'appel n'était pas justifiée d'intervenir — Compagnies ont formé un pourvoi — Pourvoi rejeté — Cadre réglementaire permettait à la Commission d'établir des tarifs justes et raisonnables pour les fournisseurs d'électricité et de gaz qui voulaient obtenir le recouvrement de leurs coûts et dépenses encourus de manière prudente, mais il n'imposait pas de méthodologie particulière pour l'établissement des tarifs — Il appartenait à la Commission de choisir quel test et quelle méthodologie employer — Commission n'était pas obligée d'utiliser une méthodologie particulière pour le test visant à déterminer la prudence lorsqu'elle révisait la prévision des coûts — Il revenait aux fournisseurs de démontrer que le tarif qu'ils proposaient était juste et raisonnable — Méthodologie utilisée par la Commission et la manière dont elle l'a appliquée étaient raisonnables compte tenu de la nature des coûts.

The Alberta Utilities Commission denied the request by a group of utility companies to recover through approved rates certain pension costs related to an annual cost of living adjustment (COLA). Instead of approving recovery for an adjustment of 100 per cent of annual consumer price index (CPI) up to a maximum COLA of 3 per cent, the Commission ruled that recovery of only 50 per cent of annual CPI was reasonable. The Alberta Court of Appeal dismissed the companies' appeal from the decision of the Commission and ruled that the analytical framework selected by the Commission was not unreasonable. A two-stage analysis of determining if expenditures were prudently incurred and then the setting of reasonable rates was not mandated and on the record, it was open to the Commission to determine that only 50 per cent of the COLA amounts should be included in the rates. The reasons for this decision explained adequately how the Commission came to that conclusion, and there was no basis for appellate intervention. The companies appealed.

Held: The appeal was dismissed.

Per Rothstein J. (McLachlin C.J.C., Abella, Cromwell, Moldaver, Karakatsanis and Gascon JJ. concurring): The applicable standard of review is reasonableness. The Commission was applying its expertise to set rates and approve payment amounts in accordance with the Electric Utilities Act and the Gas Utilities Act. The matter related to rate-making which is at the heart of a regulator's expertise and was deserving of a high degree of deference. The matter also turned on the Commission's interpretation of its home statutes, and a standard of reasonableness presumptively applied. The Alberta regulatory framework allows the Commission to set just and reasonable tariffs for electric and gas utilities seeking recovery of their prudent costs and expenses. It does not impose a specific rate-setting methodology on the Commission. It falls to the Commission to decide upon the specific test and methodology to employ. There is no obligation on the Commission to utilize a particular prudence test methodology when reviewing costs on a forecast basis. There was no need for the Commission to employ a two-step process of first examining whether the decisions to incur costs were prudent. There was no need to apply a presumption of prudence in favour of the utility. The legislation contained the specific use of the word "prudent" to qualify the costs and expenses that electric and gas utilities are entitled to recover, but that did not mandate the use of the prudence test. It is the utility that bears the onus of proving that the tariff it proposes is just and reasonable. The methodology the Commission used, and the way it applied its methodology, were reasonable given the nature of the costs.

The Commission's interpretation and exercise of its rate-setting authority was reasonable. The disallowed costs were forecast costs. The utilities were not entitled to a no-hindsight prudence review. Under the reasonableness standard of review, the Commission's interpretation of its home statute was entitled to deference. The Commission did not expressly address the question of whether the statutory regime mandated a no-hindsight approach, but its decision to proceed without using a no-hindsight prudence test implied that it understood the relevant statutes not to mandate the utilities' desired methodology. A review of the relevant statutes showed that the Commission's approach was reasonable.

L'Alberta Utilities Commission a refusé la demande présentée par un groupe de compagnies oeuvrant dans le domaine du service public en vue de recouvrer, selon les taux approuvés, certaines charges de retraite correspondant à l'ajustement annuel au coût de la vie (AACV). Au lieu d'approuver ce recouvrement à raison de 100 p. cent de l'indice des prix à la consommation (IPC) de l'année (AACV d'au plus 3 p. cent), la Commission a jugé raisonnable le recouvrement de seulement 50 p. cent de l'IPC annuel. La Cour d'appel de l'Alberta a rejeté l'appel des compagnies interjeté à l'encontre de la décision de la Commission et a décidé que le cadre d'analyse utilisé par la Commission n'était pas déraisonnable. Une analyse en deux volets visant d'abord à déterminer si les dépenses avaient été prudemment encourues puis à établir des taux raisonnables n'était pas obligatoire et, au vu du dossier, il était loisible à la Commission de conclure que seulement 50 p. cent des montants relatifs à l'AACV devrait être inclus dans les taux. Les motifs de cette décision expliquaient adéquatement la manière dont la Commission en était venu à cette conclusion et la Cour d'appel n'était pas justifiée d'intervenir. Les compagnies ont formé un pourvoi.

Arrêt: Le pourvoi a été rejeté.

Rothstein, J. (McLachlin, J.C.C., Abella, Cromwell, Moldaver, Karakatsanis, Gascon, JJ., souscrivant à son opinion) : La norme de contrôle applicable était celle de la décision raisonnable. La Commission se fiait à son expertise pour établir les taux et approuver les paiements en conformité avec l'Electric Utilities Act et la Gas Utilities Act. La question se rapportait à la décision de fixer le taux, ce qui se situait au coeur de l'expertise de l'organisme de réglementation et commandait un haut degré de déférence. La question se rapportait également à l'interprétation par la Commission de sa propre loi et il fallait présumer que la norme de la décision raisonnable s'appliquait.

Le cadre réglementaire de l'Alberta permettait à la Commission d'établir des tarifs justes et raisonnables pour les fournisseurs d'électricité et de gaz qui voulaient obtenir le recouvrement de leurs coûts et dépenses encourus de manière prudente. Il n'imposait pas à la Commission une méthodologie particulière pour l'établissement des tarifs. Il appartenait à la Commission de choisir quel test et quelle méthodologie employer. La Commission n'était pas obligée d'utiliser une méthodologie particulière pour le test visant à déterminer la prudence lorsqu'elle révisait la prévision des coûts. Il n'était pas nécessaire que la Commission emploie une analyse en deux volets visant, en premier lieu, à déterminer si les décisions d'encourir les coûts étaient prudentes. Il n'était pas nécessaire de recourir à une présomption de prudence favorisant les fournisseurs. Le mot « prudent » était utilisé dans la législation pour qualifier les coûts et dépenses qu'un fournisseur d'électricité et de gaz pouvait recouvrer, mais cela ne rendait pas obligatoire l'usage du critère de prudence. Il revenait aux fournisseurs de démontrer que le tarif qu'ils proposaient était juste et raisonnable. La méthodologie utilisée par la Commission et la manière dont elle l'a appliquée étaient raisonnables compte tenu de la nature des coûts.

L'interprétation faite par la Commission et l'exercice de son pouvoir d'établissement des tarifs étaient raisonnables. Les coûts qui n'avaient pas été autorisés étaient des coûts prévus. Les fournisseurs n'avaient pas droit à un contrôle de la prudence excluant le recul. En vertu de la norme de la décision raisonnable, l'interprétation par la Commission de sa propre loi commandait de la déférence. La Commission n'a pas traité spécifiquement de la question de savoir si le régime statutaire rendait obligatoire une approche excluant le recul, mais sa décision d'aller de l'avant sans recourir à un critère de prudence excluant le recul indiquait implicitement qu'elle comprenait que les lois applicables ne rendaient pas obligatoire l'application de la méthodologie prônée par les fournisseurs. Une revue des lois applicables démontrait que l'approche de la Commission était raisonnable.

Table of Authorities

Cases considered by *Rothstein J.*:

A.T.A. v. Alberta (Information & Privacy Commissioner) (2011), 2011 SCC 61, 2011 CarswellAlta 2068, 2011 CarswellAlta 2069, 339 D.L.R. (4th) 428, 28 Admin. L.R. (5th) 177, 52 Alta. L.R. (5th) 1, [2012] 2 W.W.R. 434, (sub nom. *Alberta Teachers' Association v. Information & Privacy Commissioner (Alta.)*) 424 N.R. 70, (sub nom. *Alberta (Information & Privacy Commissioner) v. Alberta Teachers' Association*) [2011] 3 S.C.R. 654, (sub nom. *Alberta Teachers' Association v. Information and Privacy Commissioner*) 519 A.R. 1, (sub nom. *Alberta Teachers' Association v. Information and Privacy Commissioner*) 539 W.A.C. 1 (S.C.C.) — referred to

ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board) (2006), 2006 SCC 4, 2006 CarswellAlta 139, 2006 CarswellAlta 140, 344 N.R. 293, 54 Alta. L.R. (4th) 1, [2006] 5 W.W.R. 1, 263 D.L.R. (4th) 193, 39 Admin. L.R. (4th) 159, 380 A.R. 1, 363 W.A.C. 1, [2006] 1 S.C.R. 140 (S.C.C.) — considered

ATCO Gas & Pipelines Ltd. v. Alberta (Utilities Commission) (2009), 2009 ABCA 246, 2009 CarswellAlta 983, 9 Alta. L.R. (5th) 267, 311 D.L.R. (4th) 343, 464 A.R. 275, 467 W.A.C. 275 (Alta. C.A.) — considered

ATCO Utilities, Re (2010), 2010 CarswellAlta 870, 84 C.C.P.B. 89 (Alta. U.C.) — referred to

ATCO Utilities, Re (2012), 2012 CarswellAlta 491, 97 C.C.P.B. 298 (Alta. U.C.) — referred to

AltaLink Management Ltd., Re (2012), 2012 ABCA 378, 2012 CarswellAlta 2175, 44 Admin. L.R. (5th) 199, 72 Alta. L.R. (5th) 23, (sub nom. *Shaw v. Alberta Utilities Commission*) 539 A.R. 315, (sub nom. *Shaw v. Alberta Utilities Commission*) 561 W.A.C. 315 (Alta. C.A.) — considered

British Columbia (Securities Commission) v. McLean (2013), 2013 SCC 67, 2013 CarswellBC 3618, 2013 CarswellBC 3619, 366 D.L.R. (4th) 30, [2014] 2 W.W.R. 415, (sub nom. *McLean v. British Columbia Securities Commission*) 452 N.R. 340, 53 B.C.L.R. (5th) 1, (sub nom. *McLean v. British Columbia (Securities Commission)*) [2013] 3 S.C.R. 895, (sub nom. *McLean v. British Columbia Securities Commission*) 347 B.C.A.C. 1, (sub nom. *McLean v. British Columbia Securities Commission*) 593 W.A.C. 1, 64 Admin. L.R. (5th) 237 (S.C.C.) — referred to

Edmonton (City) v. Northwestern Utilities Ltd. (1929), [1929] S.C.R. 186, [1929] 2 D.L.R. 4, 1929 CarswellAlta 114 (S.C.C.) — considered

Enbridge Gas Distribution Inc. v. Ontario (Energy Board) (2006), 2006 CarswellOnt 2106, 41 Admin. L.R. (4th) 69, 210 O.A.C. 4 (Ont. C.A.) — considered

Hydro One Networks Inc., Re (2013), 2013 ONCA 359, 2013 CarswellOnt 9792, (sub nom. *Power Workers' Union v. Ontario Energy Board*) 307 O.A.C. 109, (sub nom. *Power Workers' Union, Canadian Union of Public Employees, Local 1000 v. Ontario Energy Board*) 116 O.R. (3d) 793, 365 D.L.R. (4th) 247 (Ont. C.A.) — considered

New Brunswick (Board of Management) v. Dunsmuir (2008), 2008 SCC 9, 2008 CarswellNB 124, 2008 CarswellNB 125, D.T.E. 2008T-223, (sub nom. *Dunsmuir v. New Brunswick*) 2008 C.L.L.C. 220-020, 64 C.C.E.L. (3d) 1, 69 Imm. L.R. (3d) 1, 69 Admin. L.R. (4th) 1, 372 N.R. 1, (sub nom. *Dunsmuir v. New Brunswick*) 170 L.A.C. (4th) 1, (sub nom. *Dunsmuir v. New Brunswick*) 291 D.L.R. (4th) 577, 329 N.B.R. (2d) 1, (sub nom. *Dunsmuir v. New Brunswick*) [2008] 1 S.C.R. 190, 844 A.P.R. 1, (sub nom. *Dunsmuir v. New Brunswick*) 95 L.C.R. 65, 2008 CSC 9 (S.C.C.) — referred to

Rizzo & Rizzo Shoes Ltd., Re (1998), 1998 CarswellOnt 1, 1998 CarswellOnt 2, 154 D.L.R. (4th) 193, 36 O.R. (3d) 418 (headnote only), (sub nom. *Rizzo & Rizzo Shoes Ltd. (Bankrupt), Re*) 221 N.R. 241, (sub nom. *Adrien v. Ontario Ministry of Labour*) 98 C.L.L.C. 210-006, 50 C.B.R. (3d) 163, (sub nom. *Rizzo & Rizzo Shoes Ltd. (Bankrupt), Re*) 106 O.A.C. 1, [1998] 1 S.C.R. 27, 33 C.C.E.L. (2d) 173, 36 O.R. (3d) 418 (note), 36 O.R. (3d) 418 (S.C.C.) — considered

TransCanada Pipelines Ltd. v. Canada (National Energy Board) (2004), 2004 FCA 149, 2004 CarswellNat 987, 319 N.R. 171, 2004 CAF 149, 2004 CarswellNat 2545 (F.C.A.) — considered

Statutes considered by *Rothstein J.*:

Electric Utilities Act, S.A. 2003, c. E-5.1

Generally — referred to

s. 102 — referred to

s. 102(1) — considered

s. 102(2) — referred to

s. 121(2)(a) — considered

s. 121(4) — considered

s. 122 — considered

s. 122(1)(a) — considered

s. 122(1)(b) — considered

s. 122(1)(d) — considered

s. 122(1)(e) — considered

s. 122(1)(g) — considered

Employment Pension Plans Act, R.S.A. 2000, c. E-8

Generally — referred to

s. 13 — referred to

s. 13(5) — referred to

s. 14 — referred to

s. 48(3) — considered

Employment Pension Plans Act, S.A. 2012, c. E-8.1

s. 13 — referred to

s. 35(2) — referred to

s. 52(2)(b) — referred to

Gas Utilities Act, R.S.A. 2000, c. G-5

Generally — referred to

s. 36 — referred to

s. 36(a) — considered

s. 37(3) — considered

s. 44(1) — considered

s. 44(3) — considered

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Generally — referred to

Regulations considered by *Rothstein J.*:

Employment Pension Plans Act, R.S.A. 2000, c. E-8

Employment Pension Plans Regulation, Alta. Reg. 35/2000

s. 9 — referred to

s. 10 — referred to

Employment Pension Plans Act, S.A. 2012, c. E-8.1

Employment Pension Plans Regulation, Alta. Reg. 154/2014

s. 48 — referred to

s. 49 — referred to

s. 60(2)(b) — referred to

s. 60(3) — referred to

Gas Utilities Act, R.S.A. 2000, c. G-5

Roles, Relationships and Responsibilities Regulation, Alta. Reg. 186/2003

Generally — referred to

s. 4(3) — considered

Words and phrases considered:

just and reasonable rates

In Canadian law, "just and reasonable" rates or tariffs are those that are fair to both consumers and the utility: *Edmonton (City) v. Northwestern Utilities Ltd.*, [1929] S.C.R. 186 (S.C.C.), at pp. 192-93, per Lamont J. Under a cost of service model, rates must allow the utility the opportunity to recover, over the long run, its operating and capital costs. Recovering these costs ensures that the utility can continue to operate and can earn its cost of capital in order to attract and retain investment in the utility: [*Ontario (Energy Board) v. Ontario Power Generation Inc.*, 2015 SCC 44 (S.C.C.) *OEB*], at para. 16. Consumers must pay what the Commission "expects it to cost to efficiently provide the services they receive" such that, "overall, they are paying no more than what is necessary for the service they receive": *OEB*, at para. 20.

prudence

Because, as will be discussed, the meaning of "prudence" is the focus of much of the debate in this case, it is helpful to start by examining the ordinary meaning of the word as a baseline for the subsequent analysis. Pertinent dictionary definitions give a range of meanings for "prudent", including "having or exercising sound judgement in practical affairs" (*The Oxford English Dictionary* (2nd ed. 1989), vol. XII, at p. 729), "acting with or showing care and thought for the future" (*Concise Oxford English Dictionary* (12th ed. 2011), at p. 1156), or "marked by wisdom or judiciousness [or] shrewd in the management of practical affairs" (*Merriam-Webster's Collegiate Dictionary* (11th ed. 2003), at p. 1002). While these definitions may vary in their nuance, the ordinary sense of the word is such that a prudent cost is one which may be described as wise or sound.

However, these dictionary definitions are not so consistent and exhaustive as to provide a complete answer to the question of the meaning of "prudent" costs in the context of the Alberta utilities regulation statutes. As such, a contextual reading of the statutory provisions at issue provides further guidance. In the context of utilities regulation, I do not find any difference between the ordinary meaning of a "prudent" cost and a cost that could be said to be reasonable. It would not be imprudent to incur a reasonable cost, nor would it be prudent to incur an unreasonable cost.

revenue requirement

The . . . Utilities submit that the Commission is bound to first assess costs put forward by a utility for prudence, and that prudently incurred costs must be approved for inclusion in the utility's "revenue requirement". This term refers to "the total revenue that is required by the company to pay all of its allowable expenses and also to recover all costs associated with its invested capital": L. Reid and J. Todd, "New Developments in Rate Design for Electricity Distributors", in G. Kaiser and B. Heggie, eds., *Energy Law and Policy* (2011), 519, at p.521.

Termes et locutions cités:

Prudence

Nous verrons plus loin que le débat porte en grande partie sur la signification de la notion de « prudence », si bien qu'il est utile d'examiner d'abord le sens ordinaire de ce terme comme point de référence pour l'analyse qui suivra. Les dictionnaires offrent une gamme de définitions de l'adjectif « prudent », dont les suivantes : [TRADUCTION] « qui a ou qui exerce un bon jugement dans les affaires d'ordre pratique » (*The Oxford English Dictionary* (2e éd. 1989), vol. XII, p. 729), [TRADUCTION] « qui agit en se souciant du lendemain ou qui manifeste un tel souci » (*Concise Oxford English Dictionary* (12e éd. 2011), p. 1156), ou [TRADUCTION] « qui est empreint de sagesse ou de pertinence, [ou] qui est rompu à la gestion des affaires d'ordre pratique » (*Merriam-Webster's Collegiate Dictionary* (11e éd. 2003), p. 1002). Bien que ces définitions comportent des nuances, on peut en conclure, suivant le sens ordinaire de l'adjectif, qu'une dépense prudente est celle qui résulte d'une décision sage ou bonne.

Cependant, ces définitions ne sont pas suffisamment uniformes et exhaustives pour apporter une réponse définitive à la question de savoir ce qu'il faut entendre par des dépenses « prudentes » dans le contexte des lois qui réglementent les services publics en Alberta. Une interprétation contextuelle des dispositions législatives en cause offre donc un autre élément de réponse. Dans le contexte de la réglementation de services publics, je ne vois aucune différence entre des dépenses « prudentes » au sens ordinaire de ce terme et des dépenses que l'on pourrait qualifier de raisonnables. Ainsi, il ne serait pas imprudent de faire des dépenses raisonnables, pas plus qu'il ne serait prudent de faire des dépenses déraisonnables.

recette nécessaire

Les services publics ATCO soutiennent que la Commission doit d'abord se prononcer sur la prudence des dépenses invoquées par le service public et que les dépenses faites avec prudence doivent être approuvées aux fins de leur prise en compte dans les « recettes nécessaires » de l'entreprise. Ce poste s'entend des [TRADUCTION] « recettes dont l'entreprise a besoin au total pour le paiement de toutes ses dépenses susceptibles d'approbation et, également, pour recouvrer tous les coûts liés aux capitaux investis » (L. Reid et J. Todd, « New Developments in Rate Design for Electricity Distributors » dans G. Kaiser et B. Heggie, dir., *Energy Law and Policy* (2011), 519, p. 521).

tarification juste et raisonnable

En droit canadien, la tarification « juste et raisonnable » est celle qui est équitable tant pour le consommateur que pour le service public (*Northwestern Utilities Ltd. c. City of Edmonton*, [1929] S.C.R. 186, p. 192-193 (juge Lamont)). Selon un modèle fondé sur le coût du service, la tarification doit permettre à l'entreprise de recouvrer, à long terme, ses dépenses d'exploitation et son coût en capital. Grâce au recouvrement de ceux-ci, le service public peut continuer d'exercer ses activités et obtenir l'équivalent du coût du capital de manière à susciter l'investissement et à le maintenir. ([*Ontario (Commission de l'énergie) c. Ontario Power Generation Inc.*, 2015 CSC 44, (CÉO)], par. 16). Le consommateur doit payer ce que la Commission « prévoit qu'il en coûtera pour la prestation efficace du service » de sorte que, « globalement, il ne paie pas plus que ce qui est nécessaire pour obtenir le service » (CÉO, par. 20)

APPEAL from judgment reported at *ATCO Utilities, Re* (2013), 2013 ABCA 310, 2013 CarswellAlta 1984, 556 A.R. 376, 584 W.A.C. 376, 93 Alta. L.R. (5th) 234, 7 C.C.P.B. (2nd) 171 (Alta. C.A.).

POURVOI formé à l'encontre d'un jugement publié à *ATCO Utilities, Re* (2013), 2013 ABCA 310, 2013 CarswellAlta 1984, 556 A.R. 376, 584 W.A.C. 376, 93 Alta. L.R. (5th) 234, 7 C.C.P.B. (2nd) 171 (Alta. C.A.).

***Rothstein J.* (*McLachlin C.J.C, Abella, Cromwell, Moldaver, Karakatsanis, Gascon JJ.* concurring):**

1 In its decision of September 27, 2011, the Alberta Utilities Commission denied the request by ATCO Gas and Pipelines Ltd. and ATCO Electric Ltd. (collectively the "ATCO Utilities") to recover, in approved rates, certain pension costs related to an annual cost of living adjustment ("COLA") for 2012. Instead of approving recovery for an adjustment of 100 percent of the annual consumer price index ("CPI") (up to a maximum COLA of 3 percent), the Commission ruled that recovery of only 50 percent of annual CPI (up to a maximum COLA of 3 percent) was reasonable. The Alberta

Court of Appeal dismissed the ATCO Utilities' appeal from the decision of the Commission. The ATCO Utilities now appeal to this Court.

2 This matter was heard together with *Ontario (Energy Board) v. Ontario Power Generation Inc.*, 2015 SCC 44 (S.C.C.) ("*OEB*"), which also concerns the review of a rate-setting decision by a utilities regulator. Although the facts of the cases are different, both involve issues of methodology, and, in particular, when — if ever — a regulator is required to apply a particular regulatory tool known as the "prudent investment test" in assessing a utility's costs.

3 The ATCO Utilities submit that the Commission is bound to first assess costs put forward by a utility for prudence, and that prudently incurred costs must be approved for inclusion in the utility's "revenue requirement". This term refers to "the total revenue that is required by the company to pay all of its allowable expenses and also to recover all costs associated with its invested capital": L. Reid and J. Todd, "New Developments in Rate Design for Electricity Distributors", in G. Kaiser and B. Heggie, eds., *Energy Law and Policy* (2011), 519, at p.521. The approved revenue requirement is then to be allocated to customers in the form of just and reasonable rates. The ATCO Utilities argue that the Commission failed to properly address the prudence of such costs. They say that in the absence of an explicit contrary finding, costs are presumed to be prudent. Further, the Utilities assert that prudence is to be established based on circumstances as of the date of the cost decision — not based on hindsight and the use of information not available to the utility when the decision to incur the cost was made.

4 The Office of the Utilities Consumer Advocate of Alberta argues that the Alberta regulatory framework does not impose a specific rate-setting methodology on the Commission; it falls to the Commission to decide upon the specific test and methodology to employ. Specifically, the Consumer Advocate argues that there is no obligation on the Commission to utilize a particular prudence test methodology when reviewing costs on a forecast basis. Nor is there a presumption of prudence. On the contrary, the onus is on the utility to demonstrate that the tariff it proposes is just and reasonable.

5 As in ***OEB***, the relevant statutory framework does not impose upon the Commission the "prudence" methodology urged by the ATCO Utilities. Further, following the approach set out in ***OEB***, the methodology adopted by the Commission and its application of this methodology were reasonable in view of the nature of the costs in question. I would dismiss the appeal.

I. Regulatory Framework

6 In Alberta, the Commission sets "just and reasonable" tariffs for electric and gas utilities seeking recovery of their prudent costs and expenses: s. 121(2)(a) of the *Electric Utilities Act*, S.A. 2003, c. E-5.1 ("*EUA*"); and s. 36(a) of the *Gas Utilities Act*, R.S.A. 2000, c. G-5 ("*GUA*").

7 In Canadian law, "just and reasonable" rates or tariffs are those that are fair to both consumers and the utility: *Edmonton (City) v. Northwestern Utilities Ltd.*, [1929] S.C.R. 186 (S.C.C.), at pp. 192-93, per Lamont J. Under a cost of service model, rates must allow the utility the opportunity to recover, over the long run, its operating and capital costs. Recovering these costs ensures that the utility can continue to operate and can earn its cost of capital in order to attract and retain investment in the utility: ***OEB***, at para. 16. Consumers must pay what the Commission "expects it to cost to efficiently provide the services they receive" such that, "overall, they are paying no more than what is necessary for the service they receive": ***OEB***, at para. 20.

II. Facts

A. The Pension Plan

8 Employees of the ATCO Utilities benefit from the Retirement Plan for Employees of Canadian Utilities Limited ("CUL", the parent company of the ATCO Utilities) and Participating Companies (the "Pension Plan"). The Pension Plan is administered by CUL, which is not itself regulated by the Commission. As the Pension Plan administrator, CUL

acts in a fiduciary capacity in relation to Plan members and other Plan beneficiaries: s. 13(5) of the *Employment Pension Plans Act*, R.S.A. 2000, c. E-8. [1]

9 The Pension Plan includes a defined benefit plan (the "DB plan"), which was closed to new employees on January 1, 1997, and a defined contribution plan. The COLA applies only to the DB plan. The *Employment Pension Plans Act* requires that the DB plan be subject to actuarial calculations filed periodically with the Superintendent of Pensions for Alberta: ss. 13 and 14; [2] and ss. 9 and 10 of the *Employment Pension Plans Regulation*, Alta. Reg. 35/2000. [3] Actuarial calculations determine, *inter alia*, the contributions that an employer must make to cover a DB plan's liabilities.

10 The assets of the CUL Pension Plan are pooled between all CUL member companies, regardless of whether they are regulated utility companies (like the ATCO Utilities) or not. The required employer funding is determined on an aggregate basis. If special payments must be made to address unfunded liabilities, the aggregate funding requirement is apportioned among the member entities of the Pension Plan.

11 No employer contributions to the Pension Plan were required between 1996 and the end of 2009 because the Pension Plan was in surplus position, and thus the ATCO Utilities did not have to include such contributions in their revenue requirement applications to the Commission. In the wake of the 2008 financial crisis, the market value of the Pension Plan's assets dropped and a large unfunded liability resulted, forcing the employers participating in the Pension Plan, including the ATCO Utilities, to resume making employer contributions in 2010.

B. The Pension Plan Funding Obligations

12 Section 48(3) of the *Employment Pension Plans Act*, (2000) [4] requires that the Pension Plan be funded in accordance with actuarial valuation reports. The actuarial valuation report relevant to this appeal (the "2009 Actuarial Report") was filed with the Superintendent of Pensions for Alberta on June 29, 2010 by Mercer (Canada) Limited, the Pension Plan's actuary. The report indicated that two types of payments were required. First, it determined the estimated payments required to address the projected benefits owed to beneficiaries for 2010, 2011 and 2012. These are also called "current service costs". Second, it determined that the DB plan had an unfunded liability of $157.1 million across all CUL entities, requiring all the employers participating in the Pension Plan, including the ATCO Utilities, to make minimum annual special payments in the aggregate amount of $16.4 million until December 31, 2024 to address the liability. The ATCO Utilities alone were liable for approximately $13.9 million of the annual aggregate special payment amount.

13 The cost of living adjustment issues in this case involve both the contributions that the ATCO Utilities must make into the DB plan and the benefits paid to retirees out of the plan. With regard to the ATCO Utilities' contributions into the plan, the 2009 Actuarial Report included a provision for "post retirement pension increases" that is based on the DB plan's COLA formula and the actuarial report's assumption for inflation. This provision affects the payments that the ATCO Utilities are required to make into the DB plan for the three-year period covered by the report. In this case, this increase was 2.25 percent per year for all three years.

14 With regard to the payment of benefits to retirees under the DB plan, the ATCO Utilities' parent company CUL sets the COLA annually. Sections 6.9(a) and 6.12(a) of the DB plan prescribe that CUL determines the COLA by taking into consideration annual percentage changes in the Consumer Price Index for Canada and any previous adjustments paid. These provisions cap the adjustment set by CUL at 3 percent per annum.

III. Decisions Below

A. Alberta Utilities Commission: ATCO Utilities, Re (2010), 84 C.C.P.B. 89 (Alta. U.C.) (the "Decision 2010-189")

15 On July 10, 2009, the ATCO Utilities filed an application with the Commission to determine, *inter alia*, the amount of employer pension contributions that would be included in their revenue requirements in 2010. The ATCO Utilities' proposed contributions reflected a COLA set at 100 percent of annual Canada CPI (up to a maximum of 3 percent),

as CUL had used for a number of years. However, in the Commission's view, setting COLA at 100 percent of CPI year after year was not required by the wording of the Pension Plan. It concluded "that ratepayers should not bear any incremental pension funding costs" that arise from CUL's practice of setting COLA "where it [was] demonstrated that such incremental costs prove to be unreasonable or imprudent in the circumstances": para. 118.

16 However, the Commission did not find the evidence filed in this application to be sufficient to draw conclusions with respect to whether the COLA was prudent. As a result, it did not reduce the COLA of 100 percent of annual CPI (up to a maximum of 3 percent) for the ATCO Utilities' 2010 revenue requirements. Nonetheless, the Commission stated that it "would like to investigate the possibility of adjusting COLA as a mechanism in prudently managing utility pension expense" for the years 2011 onward: para. 123. It directed the ATCO Utilities to prepare a 2011 pension common matters application to address issues related to COLA and CUL's discretion in setting COLA.

B. Alberta Utilities Commission: 2011 CarswellAlta 1646 (Alta. U.C.) (WL Can.) (the "Decision 2011-391")

17 On December 15, 2010, the ATCO Utilities filed a pension common matters application pursuant to the Commission's direction in *Decision 2010-189*. The Commission published its *Decision 2011-391* on September 27, 2011. It is this decision that is the subject of appeal in this Court.

18 In reviewing the COLA included in the ATCO Utilities' revenue requirement application, the Commission wrote that the reasonableness of setting it at 100 percent of CPI had to be evaluated "in the circumstances applicable at the time that ATCO Utilities apply to include pension expense in revenue requirement": *Decision 2011-391*, at para. 87. The significant unfunded liability of the Pension Plan was such a circumstance. The Commission was of the view that the DB plan permitted CUL to exercise its discretion in setting the COLA, and that this discretion was "an available tool" for CUL to actively manage the DB plan unfunded liability as it carried out its fiduciary and contractual obligations: para. 83. "[T]he availability of that discretion and the exercise, or lack thereof, of that discretion [was] a relevant and material consideration" in determining whether the ATCO Utilities' pension expenses were reasonable and should be included in revenue requirements: para. 83.

19 The Commission found that the ATCO Utilities' practice of awarding an annual COLA of 100 percent of CPI every year was not "an acceptable standard practice", in light of benchmark evidence showing a wider range of COLA percentages used by defined benefit pension plans among other entities in a comparator group: *Decision 2011-391*, at para 87. The majority of the entities set COLA between 50 percent and 75 percent of CPI. The Commission also found that a reduction in COLA would not undermine the Utilities' ability to attract new employees, nor would it encourage current employees to leave.

20 The Commission concluded that the COLA included in current service costs to be recovered through tariffs after January 1, 2012 and until the next actuarial valuation should be 50 percent of the annual Canada CPI, to a maximum of 3 percent. The ATCO Utilities' revenue requirements for 2012 were to be reduced accordingly.

21 However, with regard to the special payments addressing the unfunded liability for 2012, the Commission stated that it would not require that the ATCO Utilities file an updated actuarial report reflecting a lower COLA and that it would only begin disallowing a COLA of 100 percent with regard to special payment costs from 2013 onward. This decision resulted from the Commission's conclusion that filing a new actuarial report "would be costly, and consume an undue amount of company, intervener and Commission resources given the time remaining in 2011 to complete a new report and file it for approval with the Commission and subsequently with the Superintendent of Pensions", especially as a new report would be filed by January 1, 2013 as it stood: *Decision 2011-391*, at para. 99. The Commission did not reduce special payments to be recovered in 2012 because it was not "in the best interest of ATCO Utilities, ratepayers or pensioners to implement a change to the COLA calculation [at this time] given the uncertain pension funding impacts that may result from a new actuarial valuation and report": para. 100. Reductions in liability as a result of a reduction of COLA would be captured in ongoing special payments set for 2013 onward.

C. Alberta Utilities Commission: ATCO Utilities, Re (2012), 97 C.C.P.B. 298 (Alta. U.C.) (the "Decision 2012-077")

22 On November 2, 2011, the ATCO Utilities filed a review and variance application of *Decision 2011-391*. The ATCO Utilities requested that the Commission vacate its direction to reduce the amount of COLA to 50 percent of CPI for regulatory purposes.

23 The Commission found that the arguments raised by the ATCO Utilities did not give rise to a substantial doubt as to the correctness of *Decision 2011-391* and denied the ATCO Utilities' request for review and variance.

D. Alberta Court of Appeal: 2013 ABCA 310, 93 Alta. L.R. (5th) 234 (Alta. C.A.)

24 The Alberta Court of Appeal granted leave to appeal *Decision 2011-391*. Conducting a reasonableness review, the court held it was open to the Commission to reduce the ATCO Utilities' revenue requirements to reflect a COLA of 50 percent of CPI. The Court of Appeal dismissed the Utilities' appeal.

IV. Issues

25 This appeal raises three issues:

1. What is the standard of review?

2. Does the regulatory framework prescribe a certain methodology in assessing whether costs are prudent?

3. Was it reasonable for the Commission to refuse to incorporate 100 percent of CPI to a maximum of 3 percent into the ATCO Utilities' COLA revenue requirements?

V. Analysis

A. Standard of Review

26 The standard of review of the Commission's decision in applying its expertise to set rates and approve payment amounts in accordance with the *Electric Utilities Act* and the *Gas Utilities Act* is reasonableness: *OEB*, at para. 73; see *New Brunswick (Board of Management) v. Dunsmuir*, 2008 SCC 9, [2008] 1 S.C.R. 190 (S.C.C.), at paras. 53-54.

27 Nonetheless, the ATCO Utilities argue that the jurisprudence favours applying a standard of correctness. However, the cases they cite — *ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board)*, 2006 SCC 4, [2006] 1 S.C.R. 140 (S.C.C.) ("*Stores Block*"), *AltaLink Management Ltd., Re*, 2012 ABCA 378, 539 A.R. 315 (Alta. C.A.), and *ATCO Gas & Pipelines Ltd. v. Alberta (Utilities Commission)*, 2009 ABCA 246, 464 A.R. 275 (Alta. C.A.) — are not analogous to the matter at hand. They each were said to involve "true questions of jurisdiction", where the regulator was called on to determine whether it had the statutory authority to decide a particular question. This Court's recent jurisprudence has emphasized that true questions of jurisdiction, if they exist as a category at all, an issue yet unresolved by the Court, are rare and exceptional: *A.T.A. v. Alberta (Information & Privacy Commissioner)*, 2011 SCC 61, [2011] 3 S.C.R. 654 (S.C.C.), at para. 34. In any event, this case involves ratemaking. As Bastarache J. noted in *Stores Block*, ratemaking is at the heart of a regulator's expertise and is therefore deserving of a high degree of deference: para. 30.

28 To the extent that an appeal also turns on the Commission's interpretation of its home statutes, a standard of reasonableness also presumptively applies: *A.T.A.*, at para. 30. The presumption is not rebutted in this case.

B. Methodology for Determining Costs and Just and Reasonable Rates Under the Electric Utilities Act and the Gas Utilities Act

29 The application by the ATCO Utilities, one of which is an electric utility and the other a gas utility, involves both the *EUA* and the *GUA*. Both statutes direct the Commission to set just and reasonable rates. The *EUA* requires the

Commission to "have regard for the principle that a tariff approved by it must provide the owner of an electric utility with a reasonable opportunity to recover" various "prudent" or "prudently incurred" costs: s. 122; see also s. 102. A gas utility, on the other hand, is "entitled to recover in its tariffs" costs that the Commission determines to be "prudent": s. 4(3) of the *Roles, Relationships and Responsibilities Regulation*, Alta. Reg. 186/2003 ("*RRR Regulation*"); see also s. 36 *GUA*.

30 The ATCO Utilities argue that the guarantee of a reasonable opportunity to recover their costs requires that the Commission must first examine whether the decisions to incur costs were prudent and must apply a presumption of prudence in favour of the utility. Unless these costs are found not to be prudent, they are to be included in the utility's revenue requirement. The ATCO Utilities say that in conducting its prudence inquiry, the Commission is required to use the prudence test as described by the Ontario Court of Appeal in *Hydro One Networks Inc., Re*, 2013 ONCA 359, 116 O.R. (3d) 793 (Ont. C.A.), which is the subject of the companion appeal to this case. In that case, the Ontario Court of Appeal relied on a formulation of prudence review set out in *Enbridge Gas Distribution Inc. v. Ontario (Energy Board)* (2006), 210 O.A.C. 4 (Ont. C.A.), at para. 10:

> • Decisions made by the utility's management should generally be presumed to be prudent unless challenged on reasonable grounds.
>
> • To be prudent, a decision must have been reasonable under the circumstances that were known or ought to have been known to the utility at the time the decision was made.
>
> • Hindsight should not be used in determining prudence, although consideration of the outcome of the decision may legitimately be used to overcome the presumption of prudence.
>
> • Prudence must be determined in a retrospective factual inquiry, in that the evidence must be concerned with the time the decision was made and must be based on facts about the elements that could or did enter into the decision at the time. [para.16]

31 The ATCO Utilities argue that the statutes' express use of the word "prudent" to qualify the costs and expenses that electric and gas utilities are entitled to recover necessarily mandates the use of that prudence test. I will refer to it as the "no-hindsight" test.

32 The language of the relevant provisions of the *EUA* and *GUA* differs from the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Sch. B, in the companion *OEB* appeal. While the *EUA* and the *GUA* contain specific references to "prudence", the *Ontario Energy Board Act, 1998* does not. Further, regulations passed under the *Ontario Energy Board Act, 1998* expressly permit the Ontario Energy Board to establish a methodology to determine whether revenue requirements are just and reasonable. The *EUA* and *GUA* do not include a direct grant of methodological discretion. However, like the statutory scheme in *OEB*, neither the *EUA* nor the *GUA* impose a specific methodology [5] and, as will be explained, their references to "prudence" do not impose upon the Commission the specific methodology advanced by the ATCO Utilities.

(1) Prudence Under the EUA

33 The question before this Court is whether the Commission's interpretation and exercise of its rate-setting authority was reasonable. The ATCO Utilities argue that the statutory framework supports its assertion that it was entitled to a no-hindsight prudence review. Under the reasonableness standard of review, the Commission's interpretation of its home statute is entitled to deference. In this case, the Commission did not expressly address the question of whether the statutory regime mandated a no-hindsight approach. Rather, its decision to proceed without using a no-hindsight prudence test implies that it understood the relevant statutes not to mandate the ATCO Utilities' desired methodology. It is thus necessary to examine the terms of the relevant statutes to determine whether the Commission's approach was reasonable. In doing so, this Court may make use of the traditional tools of statutory interpretation with the goal of determining whether the Commission's approach was reasonable: see *British Columbia (Securities Commission) v. McLean*, 2013 SCC 67, [2013] 3 S.C.R. 895 (S.C.C.), at paras. 37-41.

34 The words of a statute are to be interpreted "in their entire context and in their grammatical and ordinary sense harmoniously with the scheme of the Act, the object of the Act, and the intention of Parliament": *Rizzo & Rizzo Shoes Ltd., Re*, [1998] 1 S.C.R. 27 (S.C.C.), at para. 21, quoting E. A. Driedger, *Construction of Statutes* (2nd ed. 1983), at p. 87. Because, as will be discussed, the meaning of "prudence" is the focus of much of the debate in this case, it is helpful to start by examining the ordinary meaning of the word as a baseline for the subsequent analysis. Pertinent dictionary definitions give a range of meanings for "prudent", including "having or exercising sound judgement in practical affairs" (*The Oxford English Dictionary* (2nd ed. 1989), vol. XII, at p. 729), "acting with or showing care and thought for the future" (*Concise Oxford English Dictionary* (12th ed. 2011), at p. 1156), or "marked by wisdom or judiciousness [or] shrewd in the management of practical affairs" (*Merriam-Webster's Collegiate Dictionary* (11th ed. 2003), at p. 1002). While these definitions may vary in their nuance, the ordinary sense of the word is such that a prudent cost is one which may be described as wise or sound.

35 However, these dictionary definitions are not so consistent and exhaustive as to provide a complete answer to the question of the meaning of "prudent" costs in the context of the Alberta utilities regulation statutes. As such, a contextual reading of the statutory provisions at issue provides further guidance. In the context of utilities regulation, I do not find any difference between the ordinary meaning of a "prudent" cost and a cost that could be said to be reasonable. It would not be imprudent to incur a reasonable cost, nor would it be prudent to incur an unreasonable cost.

36 The *EUA* provides that an "owner of an electric distribution system must prepare a distribution tariff for the purpose of recovering the *prudent* costs of providing electric distribution service by means of [its] electric distribution system": s. 102(1). To receive approval for the distribution tariff, the owner must apply to the Commission: s. 102(2) *EUA*. When considering a tariff application, the Commission must ensure, *inter alia*, that the tariff is "just and reasonable" (s. 121(2)(a) *EUA*), a requirement for which the burden of proof "is on the person seeking approval of the tariff" (s. 121(4) *EUA*).

37 Section 122 of the *EUA* provides that the Commission "must have regard for the principle that a tariff approved by it must provide the owner of an electric utility with a reasonable opportunity to recover" a series of eight types of costs and expenses:

> a) the costs and expenses associated with capital related to the owner's investment in the electric utility, ...
>
> . . . . .
>
> if the costs and expenses are *prudent*...
>
> b) other *prudent costs and expenses* associated with isolated generating units, transmission, exchange or distribution of electricity ... if, in the Commission's opinion, they are applicable to the electric utility,
>
> c) amounts that the owner is required to pay under this Act or the regulations,
>
> d) the costs and expenses applicable to the electric utility that arise out of obligations incurred before the coming into force of this section and that were approved by the Public Utilities Board, the Alberta Energy and Utilities Board or other utilities' regulatory authorities if, in the Commission's opinion, the costs and expenses continue to be *reasonable and prudently incurred*,
>
> e) its *prudent costs and expenses* of complying with the Commission rules respecting load settlement,
>
> f) its prudent costs and expenses respecting the management of legal liability,
>
> g) the costs and expenses associated with financial arrangements to manage financial risk associated with the pool price if the arrangements are, in the Commission's opinion, prudently made, and
>
> h) any other prudent costs and expenses that the Commission considers appropriate, including a fair allocation of the owner's costs and expenses that relate to any or all of the owner's electric utilities.

38 Section 122 refers to prudence in two different ways. Most frequently, the adjective "prudent" qualifies the expression "costs and expenses", which indicates that a utility enjoys a reasonable opportunity to recover costs and expenses that are prudent. Absent a definition of the word "prudent" or a clear inference that it refers to a no-hindsight rule as described in *Enbridge*, this prudence requirement is to be understood in the sense of the ordinary meaning of the word: for the listed costs and expenses to warrant a reasonable opportunity of recovery, they must be wise or sound; in other words, they must be reasonable.

39 By contrast, certain provisions use the adverb "prudently" to qualify the utility's decision to incur costs: s. 122(1)(d) speaks of costs and expenses that are "reasonable and prudently incurred" and s. 122(1)(g) refers to costs and expenses associated with financial arrangements that were "prudently made". Though this case does not call upon this Court to evaluate the types of expenses covered by s. 122(1)(d) or (g), statutory language referring to "prudently incurred" costs appears to speak more directly to a utility's decision to incur costs at the time the decision was made. Such language may more directly implicate the no-hindsight approach urged by the ATCO Utilities in this case than language that merely speaks of "prudent costs". This issue is further complicated for costs arising under s. 122(1)(d), where costs must both "continue to be reasonable *and* prudently incurred". The proper interpretation of these provisions is a question best left for a case in which the issue arises.

40 In their submissions, the ATCO Utilities do not parse the different contexts in which the word "prudent" is used in s. 122. They argue more generally that the references to "prudence" imply that a no-hindsight test is required, and that a utility's costs must be presumed to be prudent.

41 However, the different uses of "prudence" in s. 122 are instructive. If the statute requires the Commission to approve "prudently incurred" expenses, it may be unreasonable for the Commission to fail to apply a no-hindsight methodology in reviewing such expenses. However, the costs at issue in this case do not fall within the categories of costs for which the statute grants recovery of "prudently incurred" costs. The use of the adjective "prudent" to qualify "costs and expenses" elsewhere in s. 122 does not itself imply a specific methodology. Nothing in the ordinary meaning of the word "prudent" or the use of this word in the statute as a stand-alone condition says anything about the time at which prudence must be evaluated.

42 Further, s. 121(4) of the *EUA* provides that the burden of establishing that the proposed tariffs are just and reasonable falls on the public utility. The requirement that tariffs be just and reasonable is a foundational requirement of the tariff-setting provisions of the *EUA.* Tariffs will not be just and reasonable if they do not comply with the statutory requirement of s. 122 that the costs and expenses be prudent. Thus, contrary to the ATCO Utilities' proposed methodology, the utilities' burden to establish that tariffs are just and reasonable necessarily imposes on the utilities the burden of establishing that costs are prudent.

43 In sum, neither the ordinary meaning of "prudent" nor the statutory language indicate that the Commission is bound by the *EUA* to apply a no-hindsight approach to the costs at issue, nor is a presumption of prudence statutorily imposed in these circumstances.

(2) Prudence Under the GUA

44 The *GUA* requires, *inter alia*, that on application by the owner of a gas utility, the Commission "fix just and reasonable" rates that "shall be imposed, observed and followed afterwards by the owner of the gas utility": s. 36(a). Section 44(1) provides that changes in rates must be approved by the Commission, and the "burden of proof to show that the increases, changes or alterations are just and reasonable is on the owner of the gas utility seeking to make them": s. 44(3). Further, s. 4(3) of the *RRR Regulation* provides that

> [a] gas distributor is entitled to recover in its tariffs the prudent costs as determined by the Commission that are incurred by the gas distributor ....

45 While the *RRR Regulation* makes a specific reference to the recovery of "prudent" costs, I do not read this prudence requirement as implying a presumption of prudence and application of a no-hindsight rule. Regarding the "no hindsight" element, the statutory provisions do not use "prudent" to describe the decision to incur the costs, but rather to describe the costs themselves. Although s. 4(3) of the *RRR Regulation* uses the term "incurred", it is used to indicate that the provision applies to costs incurred by the utility. No temporal inference can be drawn from the use of "incurred" in this context; it is not used in a manner that calls for examination of the prudence of the decision to incur certain costs. The inquiry under s. 4(3) of the *RRR Regulation* rather asks whether the costs themselves can be said to be "prudent". The *GUA* does not include a requirement that a no-hindsight rule must apply in assessing whether costs are prudent, nor does the text of the *GUA* or the *RRR Regulation* imply such a rule. Regarding a presumption of prudence, s. 44(3) of the *GUA* stipulates that the utility has the burden to establish that the rates are just and reasonable. Like the *EUA*, this in turn places the burden of establishing the prudence of costs on the utility.

(3) Conclusion With Respect to Statutory Requirements of the EUA and GUA

46 Though the statutes do contain language allowing for the recovery of "prudent" costs, the *EUA* and the *GUA* do not explicitly impose an obligation on the Commission to conduct its analysis using a particular methodology any time the word "prudent" is used. Further, reserving any opinion on whether the term "prudently incurred" might require a particular no-hindsight methodology, in this particular case the bare use of the word "prudent" does not, on its own, mandate a particular methodology.

47 It is thus apparent that the relevant statutes may reasonably be interpreted not to impose the ATCO Utilities' asserted prudence methodology on the Commission. The existence of a reasonable interpretation that supports the Commission's implied understanding of its discretion is enough for the Commission's decision to pass muster under reasonableness review: *McLean*, at paras. 40-41. Thus, the Commission is free to apply its expertise to determine whether costs are prudent (in the ordinary sense of whether they are reasonable), and it has the discretion to consider a variety of analytical tools and evidence in making that determination so long as the ultimate rates that it sets are just and reasonable to both consumers and the utility.

C. Characterization of the Costs at Issue: Forecast or Committed

48 As explained in *OEB*, understanding whether the costs are committed or forecast may be helpful in reviewing the reasonableness of a regulator's choice of methodology: see para. 83. Committed costs are those costs that a utility has already spent or that were committed as a result of a binding agreement or other legal obligation that leaves the utility with no discretion as to whether to make the payment in the future: para. 82. If the costs are forecast, there is no reason to apply a no-hindsight prudence test because the utility retains discretion whether to incur the costs: para. 83. By contrast, the no-hindsight prudence test may be appropriate when the regulator reviews utility costs that are committed: paras. 102-05.

49 Determining whether particular costs are committed or forecast turns on factual evidence relevant to those costs as well as on legal obligations that may govern them. Factual evidence may take the form of details regarding the structure of the utility's business, relevant conduct on the part of the utility, and the factual context in which the costs arise. Legal issues may relate to any contractual, fiduciary or regulatory obligations that grant or bar discretion on the part of the utility in incurring the costs at issue. Where the regulator has made an assessment of whether the costs are committed or forecast, that assessment is owed deference by this Court.

50 On the basis of the evidence and the arguments before it, the Commission found that the "COLA amount ha[d] not yet been awarded for 2012 because consideration of the COLA adjustment occurs towards the end of the calendar year": *Decision 2011-391*, at para. 93. The Commission concluded that there was enough time from the date *Decision 2011-391* was published on September 27, 2011 to the end of the calendar year for the ATCO Utilities and their parent CUL "to prospectively decide whether to separately fund any difference CUL may choose to pay beyond the COLA level

approved for regulatory purposes for 2012 onwards": para. 93. This finding supports a characterization of the disallowed COLA costs as forecast because their disallowance left it open to CUL to reduce the COLA that would apply to the 2012 benefit payments to 50 percent of CPI or to incur the COLA of 100 percent of CPI regardless, knowing that the differential would ultimately be borne by the utilities: *OEB*, at para. 82.

51 However, the Commission did not disallow the use of a COLA of 100% of CPI (up to a maximum of 3 percent) with regard to the special payments intended to address the unfunded liability and fixed by the 2009 Actuarial Report for the year 2012. The Commission did so by reasoning that any consumer overpayment that resulted in 2012 would be compensated through reduced special payments once a new report was prepared for 2013 onward.

52 In their factum in this Court, the ATCO Utilities submitted that the COLA costs were committed in the same way as the costs fixed by binding collective agreements were in the companion *OEB* appeal. In oral argument, counsel for the ATCO Utilities explained that the pension actuary prepares an actuarial report at intervals of a maximum of three years and files it with the Superintendent of Pensions: see ss. 13 and 14 of the *Employment Pension Plans Act* (2000) [6] and ss. 9 and 10 of the *Employment Pension Plans Regulation*, (2000). [7]

53 In this case, the 2009 Actuarial Report applied for the years 2010, 2011 and 2012. The pension actuary determined the employer's required contribution to fund projected benefits owed to beneficiaries and to address any unfunded liability in the DB plan. For each of the three years covered by the report, the actuary assumed a post retirement pension increase of 2.25 percent per year to be included in required contributions [8] . It was argued by the ATCO Utilities that the employer is required by law to make such contributions: s. 48(3) of the *Employment Pension Plans Regulation* (2000) [9]. Accordingly, the ATCO Utilities submitted that once the actuarial report covering 2010, 2011 and 2012 had been filed, the amounts identified in that valuation, including a post retirement pension increase of 2.25 percent, should be understood as committed.

54 To address this argument, a distinction must be drawn between the COLA that is used to determine the post retirement pension increases applied to employer contributions paid into the DB plan, and the COLA applied to benefit payments paid out of the plan. While the ATCO Utilities were legally bound to make contributions including a post retirement pension increase of 2.25 percent into the plan for 2012, the actual COLA paid out to beneficiaries was set by CUL on an annual basis. The ATCO Utilities' information responses to the Commission in preparation for their 2011 pension common matters application show that the actual COLA set by CUL for 2010 was 0 percent and for 2011 was 1.7 percent.

55 The ATCO Utilities' argument that the costs are committed rests on the notion that if the Commission reduces the recoverable COLA to 50 percent of CPI (up to a maximum of 3 percent), they risk incurring a shortfall because the COLA recovered through rates will be less than the post retirement pension increases of 2.25 percent that they were legally obliged to contribute.

56 However, while both the employer contributions into the DB plan and the benefit payments made to beneficiaries are subject to cost of living adjustments, the portion of *Decision 2011-391* at issue in this appeal was concerned specifically with the reasonableness of the COLA to be set by CUL for the 2012 benefit payments. As such, the Commission's disallowance was with respect to the COLA benefits to be paid out to beneficiaries in 2012 — not to the employer contributions into the DB plan.

57 Contrary to the submissions of the ATCO Utilities, the facts of this case are different from those in *OEB*. In *OEB*, the utility was bound to pay certain costs by virtue of collective agreements with separate counterparties, the employee unions. In this case, the Commission found that the COLA applied to benefit payments from the DB plan was set by the ATCO Utilities' parent, CUL, and that CUL retained discretion over the setting of the COLA for the test period. DB plan members would ultimately receive benefits reflecting a COLA of 100 percent in 2012 only if CUL decided to set the COLA at that level.

58 CUL may have exercised that discretion in such a way as to avoid saddling its regulated subsidiary with costs it knew would not be recovered. Accordingly, while the ATCO Utilities were required to make contributions reflecting a post retirement pension increase of 2.25 percent into the DB plan pursuant to the 2009 Actuarial Report, the COLA applied to benefit payments for 2012 was not committed when the Commission issued its *Decision 2011-391*. This is so because at the time *Decision 2011-391* was published, CUL had yet to set COLA for 2012.

59 It was not unreasonable for the Commission to decide, without applying a no-hindsight analysis, that 50 percent of CPI (up to a maximum of 3 percent) "represent[ed] a reasonable level for setting the COLA amount for the purposes of determining the pension cost amounts for regulatory purposes" in 2012: *Decision 2011-391*, at para. 92.

D. Considering the Impact on Rates in Evaluating Costs

60 The ATCO Utilities argue that in considering the prudence of the COLA costs the Commission was preoccupied with the aim of reducing rates charged to customers.

61 As discussed above, a key principle in Canadian regulatory law is that a regulated utility must have the opportunity to recover its operating and capital costs through rates: *OEB*, at para. 16. This requirement is reflected in the *EUA* and *GUA*, as these statutes refer to a reasonable opportunity to recover costs and expenses so long as they are prudent. A regulator must determine whether a utility's costs warrant recovery on the basis of their reasonableness — or, under the *EUA* and *GUA*, their "prudence". Where costs are determined to be prudent, the regulator must allow the utility the opportunity to recover them through rates. The impact of increased rates on consumers cannot be used as a basis to disallow recovery of such costs. [10] This is not to say that the Commission is not required to consider consumer interests. These interests are accounted for in rate regulation by limiting a utility's recovery to what it reasonably or prudently costs to efficiently provide the utility service. In other words, the regulatory body ensures that consumers only pay for what is reasonably necessary: *OEB*, at para. 20.

62 In this case, the Commission did emphasize the effect that reducing the COLA would have on the ATCO Utilities' unfunded liability. It is also true that a lower unfunded liability based on an actuarial report using a 50 percent COLA instead of 100 percent would mean a lower revenue requirement, and thus lower rates passed on to consumers. However, I do not agree with the ATCO Utilities' submission that the Commission, in considering the effect of COLA on the utilities' unfunded pension liability, was basing its disallowance on concerns about rate hikes for consumers. Regulators may not justify a disallowance of prudent costs solely because they would lead to higher rates for consumers. But that does not mean a regulator cannot give any consideration to the magnitude of a particular cost in considering whether the amount of that cost is prudent.

63 Indeed, it seems axiomatic that any time a regulator disallows a cost, that decision will be based on a conclusion that the cost is greater than ought to be permitted, which leads to the inference that consumers would be paying too much if the cost were incorporated into rates. But that is not the same as disallowing a cost *solely* because it would increase rates for consumers. In this case, the Commission found it unreasonable for the ATCO Utilities to receive payments to cover a COLA of 100 percent while they carried a large unfunded liability on their books, in part because of evidence from comparator companies that COLA figures of less than 100 percent were common, and because of the Commission's finding that a COLA of 100 percent was not necessary to ensure that the ATCO Utilities could attract and retain employees. While this conclusion carries with it the consequence that rates will be lower as a result, the Commission reasoned from the prudence of the costs themselves, not from a desire to keep rates down, to arrive at its conclusion to disallow costs. I find nothing unreasonable in the Commission's reasoning in this regard.

VI. Conclusion

64 The Commission was not statutorily bound to apply a particular methodology to the costs at issue in this case. The use of the word "prudent" in the *EUA* and *GUA* cannot by itself be read to impose upon the Commission the specific no-hindsight methodology urged by the ATCO Utilities.

65 While there are undoubtedly situations in which a failure to apply a no-hindsight methodology may result in unjust outcomes for utilities, and thus violate the statutory requirement that rates must strike a just and reasonable balance between consumer and utility interests, the Commission did not act unreasonably in this case. The disallowed costs were forecast costs. Accordingly, it was reasonable in this case for the Commission to evaluate the ATCO Utilities' proposed revenue requirement in light of all relevant circumstances. Further, because the Commission did not use impermissible methodology, it was not unreasonable for the Commission to direct the ATCO Utilities to reduce their pension costs incorporated into revenue requirements by restricting annual COLA to 50 percent of CPI (up to a maximum of 3 percent) for current service costs from 2012 onward and for special payments addressing the unfunded liability from 2013 onward.

66 For these reasons, I would dismiss the appeal.

Appeal dismissed.

Pourvoi rejeté.

Footnotes

1 This provision has since been replaced by s. 35(2) of the *Employment Pension Plans Act*, S.A. 2012, c. E-8.1.

2 These provisions have since been replaced by s. 13 of the *Employment Pension Plans Act*, (2012).

3 These provisions have since been replaced by ss. 48 and 49 of the *Employment Pension Plans Regulation*, Alta. Reg. 154/2014.

4 This provision has since been replaced by s. 52(2)(b) of the *Employment Pension Plans Act* (2012).

5 The *GUA* does provide some methodological guidance to the Commission with regard to calculating a utility's return on its rate base by specifying what information may be considered in this process: "In fixing the fair return that an owner of a gas utility is entitled to earn on the rate base, the Commission shall give due consideration to all facts that in its opinion are relevant"; (s. 37(3)). However, it does not provide any further methodological guidance for assessing the recoverability of a utility's costs.

6 These provisions have since been replaced by s. 13 of the *Employment Pension Plans Act* (2012).

7 These provisions have since been replaced by ss. 48 and 49 of the *Employment Pension Plans Regulation* (2014).

8 For clarity, the 2009 Actuarial Report and the DB plan use two separate terms to describe annual pension benefit increases, though they are conceptually linked: the DB plan refers to cost of living adjustment (or COLA), while the 2009 Actuarial Report refers to "post retirement pension increases". The 2009 Actuarial Report's post retirement pension increase figure of 2.25 percent was based on the DB plan's formula for COLA and the actuarial report's assumption for inflation.

9 This provision has since been replaced by ss. 60(2)(b) and 60(3) of the *Employment Pension Plans Regulation* (2014).

10 Regulators may, however, take into account the impact of rates on consumers in deciding *how* a utility is to recover its costs. Sudden and significant increases in rates may, for example, justify a regulator in phasing in rate increases to avoid "rate shock", provided the utility is compensated for the economic impact of deferring its recovery: *TransCanada Pipelines Ltd. v. Canada (National Energy Board)*, 2004 FCA 149, 319 N.R. 171 (F.C.A.), at para. 43.

2014 ABCA 28
Alberta Court of Appeal

ATCO Pipelines, Re

2014 CarswellAlta 67, 2014 ABCA 28, [2014] A.W.L.D. 1183, 236 A.C.W.S. (3d) 1036, 566 A.R. 323, 597 W.A.C. 323, 89 Alta. L.R. (5th) 217

Atco Gas and Pipelines Ltd. Appellant and Alberta Utilities Commission and Office of the Utilities Consumer Advocate Respondents

Carole Conrad, Ronald Berger, Peter Martin JJ.A.

Heard: June 11, 2013
Judgment: January 20, 2014
Docket: Calgary Appeal 1201-0090-AC

Proceedings: allowing leave to appeal *ATCO Pipelines, Re* (2012), 2012 ABCA 273, 2012 CarswellAlta 1569 (Alta. C.A.); affirming *ATCO Pipelines, Re* (2012), 2012 CarswellAlta 462 (Alta. U.C.)

Counsel: H.M. Kay, Q.C., N.M. Gretener for Appellant
B.C. McNulty for Respondent, Alberta Utilities Commission
T.D. Marriott for Respondent, Utilities Consumer Advocate

Subject: Public; Civil Practice and Procedure
Related Abridgment Classifications
Public law
IV Public utilities
IV.4 Termination, valuation and privatization
IV.4.e Disposal of assets
Headnote
Public law --- Public utilities — Termination, valuation and privatization — Disposal of assets
Appellant ATCO Gas and Pipelines Ltd. (ATCO) were involved in lengthy proceedings before Alberta Utilities Commission (commission) in relation to identified surplus assets, possibility of disposing of them and/or of excluding them from its rate base — Judicial ruling held that utilities could dispose of assets whose price had been included in rate base calculations where they were no longer necessary for utility business without obtaining leave from commission — ATCO requested confirmation from commission that restrictions imposed regarding assets could be removed, but requirements remained unresolved and assets remained in rate base — Commission determined scope of assets to be removed from rate base, that effective date of removal would be July 1, 2009 and directed that any costs of subdivision or other process were to be borne by ATCO's shareholders — ATCO's application for leave to appeal was granted — ATCO appealed commission's decision — Appeal dismissed — Commission did not err in law by making its decision to remove assets from rate base effective July 1, 2009 and its decision was not unreasonable — Assets not being used or required to be used for utility service were not to be included in rate base — Utility service had responsibility to withdraw assets from rate base once assets were no longer used or required and no commission approval was required but such removal was subject to prudency review by commission — Decision fell squarely within commission's mandate, was not unreasonable and was owed deference — Commission did not err in law or act unreasonably in exercising its discretionary power — Depending on specific facts and circumstances, decision to remove portion of asset from rate base and method of doing so might raise many considerations including whether asset could be physically, practically or legally divided; ease of division; associated costs involved and who should pay them; length of time asset had been in rate base; whether divided portion had other potential uses; and generally whether exclusion of portion of asset from rate

base was just and reasonable in circumstances — Commission could not order ATCO to legally subdivide its quarter of land — Eastern portion of quarter section currently in rate base was no longer required for operational purposes — Commission's decision was reasonable.

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s. 26 — considered

s. 26(2)(d) — considered

s. 36 — considered

s. 37 — referred to

s. 37(1) — considered

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s. 37 — referred to

Regulations considered by *Carole Conrad J.A.* and *Peter Martin J.A.*:

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Generally — referred to

APPEAL by ATCO Pipelines Ltd. from Alberta Utilities Commission decision reported at *ATCO Pipelines, Re* (2012), 2012 CarswellAlta 462 (Alta. U.C.), removing certain assets from rate base effective July 2009.

***Carole Conrad J.A.*:**

Introduction

1 The appellant, Atco Gas and Pipelines Ltd. [Atco] appeals from a decision of the Alberta Utilities Commission [Commission], Decision 2012-068 [2012 CarswellAlta 462 (Alta. U.C.)], removing certain assets related to Atco's salt cavern storage facilities from the rate base effective July 2009. The decision arose from Atco's application to dispose of certain assets it had determined were no longer used or required in the operations of the utility.

Issues

2 Leave to appeal was granted on two grounds:

i. Did the Commission err in setting an effective date for removal of the Salt Cavern Excess Assets from the rate base at July 1, 2009?

ii. Did the Commission err by requiring Atco to bear the costs and burdens attributed to non-utility use of portions of a single, indivisible asset originally acquired for the purposes of the utility?

Decision

3 The appeal is dismissed.

Issue one:

4 The Commission did not err in law by making its decision to remove assets from the rate base effective July 1, 2009; nor was its decision unreasonable.

Issue two:

5 This issue deals with the removal of a portion of an asset from the rate base where that portion is no longer required for utility purposes. There is little authority on this issue and every case will have to be dealt with on its circumstances.

6 Depending on the specific facts and circumstances, the decision to remove a portion of an asset from the rate base and the method of doing so may raise many considerations including such matters as: whether the asset can be physically, practically or legally divided; ease of division; associated costs involved and who should pay them; length of time the asset has been in the rate base; whether the divided portion has other potential uses; and generally whether exclusion of a portion of an asset from the rate base is just and reasonable in all the circumstances.

7 Here it was common ground that the eastern portion of the quarter section currently in the rate base was no longer required for operational purposes. The Commission determined to remove value for that portion from the rate base and the land was then available for Atco's separate use. The Commission also consented to future disposition in the event the utility eventually determined a sale was desirable on the understanding that the utility pay any associated costs of subdivision.

8 The standard of review is one of reasonableness and in all the circumstances of this case, I cannot say that the decision is unreasonable.

Background

9 Atco Gas and Pipelines Ltd is a gas utility within the meaning of the *Gas Utilities Act*, RSA 2000, c G-5, regulated by the Commission pursuant to that Act, the *Gas Utilities Designation Regulation*, AR 257/2007, the *Public Utilities Act*, RSA 2000, c P-45, and the *Alberta Utilities Commission Act*, SA 2007, c A-37.2. The Commission regulates the rates and tariffs of the two divisions of Atco Gas and Pipelines Ltd, namely, Atco Gas which operates the gas distribution utility and Atco Pipelines which operates a natural gas transmission utility. This appeal arises from an application of Atco Gas division. The Commission determines revenue requirements and utility rate base, and sets rates pursuant to sections 36 and 37 of the *Gas Utilities Act.*

10 Under section 26(2)(d) of the *Gas Utilities Act*, a disposition of an asset by Atco outside the ordinary course of business requires the prior consent of the Commission.

11 Decision 2012-068, under appeal, arises from Atco's application pursuant to section 26(2)(d) for Commission approval of the disposition of certain salt cavern assets to an affiliated company. It was intended that the balance of the salt cavern assets were to remain in the rate base, revenue requirement and rates.

12 The decision under appeal has a long procedural history. Atco originally acquired the salt caverns land in the early 1980s to store natural gas to meet peak winter demand periods. In 2007, Atco estimated 75 per cent of the salt cavern

lands had no foreseeable regulated gas transmission use due to the existence of alternative, less costly means to store natural gas. The net book values for the lands and related pipeline assets were close to $4 million.

13 Atco's efforts to dispose of certain portions of the salt caverns began on October 1, 2007, when it filed its 2008-2009 general rate application with the Commission (then the Alberta Energy and Utilities Board). That application proposed, effective December 31, 2007, to remove from the rate base and customer rates certain assets Atco described as the "Identified Salt Cavern Assets" on the basis the assets were no longer used or required to be used to provide utility service. At that time, the Identified Salt Cavern Assets were larger in scope and size than the assets subsequently included in Atco's April 27, 2011 application giving rise to this appeal.

14 On November 6, 2007, the Board ordered Atco to revise its general rate application and include the Identified Salt Cavern Assets in the general rate as the Board viewed the unilateral removal of the Identified Salt Cavern Assets from the rate base as a disposal under section 26(2)(d) of the *Gas Utilities Ac*t, requiring the Board's consent (Decision 2012-068 at para 22). Atco re-filed, and on February 1, 2008, Atco applied for approval to transfer the Identified Salt Cavern Assets to a non-utility affiliate. This proceeding was held in abeyance as the Commission had initiated an industry-wide inquiry to consider the impact of recent case law on utility asset dispositions.

15 Atco wrote the Commission on July 21, 2008, stating that based on this court's decision in *ATCO Gas South, Re*, 2008 ABCA 200, 433 A.R. 183 (Alta. C.A.); leave to appeal refused, [2008] S.C.C.A. No. 347 (S.C.C.) [the *Carbon* decision], Atco had decided not to sell the Identified Salt Cavern Assets. Atco again indicated it wanted to remove the Identified Salt Cavern Assets from the rate base, but Atco would maintain ownership of the assets.

16 On July 30, 2008, the Commission replied and restated its position that an application under section 26(2)(d) was required to determine whether the assets could be removed from the rate base (Decision 2012-068 at para 29).

17 Atco appealed the Commission's orders of November 6, 2007 and July 30, 2008 preventing Atco from removing the assets from the rate base. On June 30, 2009, this court held that ceasing use was not a disposition falling within section 26. Thus, a utility company that owns an asset included in the rate base calculations but no longer necessary for regulated utility business, could remove the asset from the rate base without obtaining consent from the Commission under section 26 of the *Gas Utilities Act*: *ATCO Gas & Pipelines Ltd. v. Alberta (Utilities Commission)*, 2009 ABCA 246, 464 A.R. 275 (Alta. C.A.); leave to appeal refused, (2010), [2009] S.C.C.A. No. 401 (S.C.C.) [the *Salt Caverns* decision]. In so deciding, this court held that section 26 did not apply to the ending of a use where no third party transfer or sale is contemplated because a "disposition" of the asset would not occur. That decision noted that no harm would be done because a removal from use would still be subject to the Commission's assessment of prudence. If the Commission found that removal was imprudent, it "could make some adjustment of values in rate base or in the expenses or return on investment, so that rates approved would not make the consumers pay rates based on that types of imprudence" (para 53).

18 Subsequent to the *Salt Caverns* decision, by letter dated July 17, 2009, Atco requested the Commission to confirm that Identified Salt Cavern Assets could be removed from its negotiation discussions relating to its 2010-2012 revenue requirements. The restriction was removed by Decision 2009-111 on July 24, 2009 [2009 CarswellAlta 1132 (Alta. U.C.)] on several conditions including the provision of information to the Commission so it could determine the prudence of the removal.

19 In Decision 2009-033 [2009 CarswellAlta 413 (Alta. U.C.)], the Commission approved a negotiated settlement agreement with respect to Atco's 2008-2009 revenue requirements. This settlement agreement specifically precluded issues related to the Identified Salt Cavern Assets.

20 In Decision 2010-228 [2010 CarswellAlta 1282 (Alta. U.C.)], the Commission approved a negotiated settlement agreement with respect to Atco's 2010-2012 revenue requirements. The Identified Salt Cavern Assets were assigned a placeholder status (reserving the issue of the salt cavern assets for future determination) to prevent unduly delaying the proceeding.

21 On January 22, 2010, after several negotiated settlements failed to decide the fate of the Identified Salt Cavern Assets, the Commission approved Atco's request to deal with the salt cavern assets in a separate proceeding. Those proceedings gave rise to Decision 2012-068 — the decision now under appeal.

Decision 2012-068

22 The Commission found that the proposed disposition of surplus assets did not offend the "no-harm test" traditionally employed by it and its predecessors as rates and services would not be adversely impacted. It determined, however, that the portion of the salt cavern assets no longer "used or required to be used to provide utility service" under section 37 of the *Gas Utilities Act* was broader than the Surplus Assets listed in Atco's April 2011 application.

23 As a result, the Commission directed Atco to remove from the rate base and revenue requirements the "Surplus Assets" (SW 34-55-21-W4M quarter section, a disposal well on that land and a water system transporting water from the North Saskatchewan River) and the "Additional Assets" (the eastern half of SE 34-55-21-W4M quarter section and the well located on the land). The decision also ordered the "Related Assets" (water infrastructure, brine disposal infrastructure and control fluid infrastructure) be removed from the rate base and revenue requirements. Collectively, the assets ordered to be removed were referred to as the "Salt Cavern Excess Assets".

24 The Commission also directed that if Atco wished to dispose of the Related Assets and the Additional Assets, including subdivision of the SE 34-55-21-W4M in the Additional Assets, the Commission approved such disposition, with all costs, including subdivision to be borne by Atco's shareholders.

25 The Commission backdated the effective date of the removal of the assets to July 1, 2009, the day following issuance of the *Salt Caverns* decision, on the basis that Atco knew at that time that it did not require the Commission's consent to remove the assets from the rate base.

Standard of Review

26 As a specialized and expert tribunal charged with the administration of a comprehensive set of legislation regulating all aspects of the energy industry in the Province of Alberta, decisions of the Commission are entitled to a high degree of curial deference. Decisions requiring the interpretation of its governing statutes and regulations, and the application of its experience and expertise, will be measured on a standard of reasonableness: *Coalition of Citizens Impacted by the Caroline Shell Plant v. Alberta (Energy & Utilities Board)* (1996), 187 A.R. 205 (Alta. C.A.) at para 14.

27 There is no true jurisdictional issue and there was no breach of the rule against impermissible retroactive rate making.

28 I am satisfied that the standard of review for the two issues on this appeal is one of reasonableness.

Issue 1: Did the Commission err in setting an effective date for removal of the Salt Cavern Excess Assets from the rate base at July 1, 2009?

29 A regulatory authority fixes just and reasonable rates pursuant to sections 36 and 37(1) of the Act which reads as follows:

> 36 The Commission, on its own initiative or on the application of a person having an interest, may by order in writing, which is to be made after giving notice to and hearing the parties interested,
>
> > (a) fix just and reasonable individual rates, joint rates, tolls or charges or schedules of them, as well as commutation and other special rates, which shall be imposed, observed and followed afterwards by the owner of the gas utility,

(b) fix proper and adequate rates and methods of depreciation, amortization or depletion in respect of the property of any owner of a gas utility, who shall make the owner's depreciation, amortization or depletion accounts conform to the rates and methods fixed by the Commission,

(c) fix just and reasonable standards, classifications, regulations, practices, measurements or service, which shall be furnished, imposed, observed and followed thereafter by the owner of the gas utility,

(d) require an owner of a gas utility to establish, construct, maintain and operate, but in compliance with this and any other Act relating to it, any reasonable extension of the owner's existing facilities when in the judgment of the Commission the extension is reasonable and practical and will furnish sufficient business to justify its construction and maintenance, and when the financial position of the owner of the gas utility reasonably warrants the original expenditure required in making and operating the extension, and

(e) require an owner of a gas utility to supply and deliver gas to the persons, for the purposes, at the rates, prices and charges and on the terms and conditions that the Commission directs, fixes or imposes.

37(1) In fixing just and reasonable rates, tolls or charges, or schedules of them, to be imposed, observed and followed afterwards by an owner of a gas utility, the Commission shall determine a rate base for the property of the owner of the gas utility used or required to be used to provide service to the public within Alberta and on determining a rate base it shall fix a fair return on the rate base.

30 As set out in *Salt Caverns* at para 20, a regulatory authority looks at two components when fixing just and reasonable rates, namely:

(1) current expenses and taxes, and

(2) an annual amount constituting a just and proper return on capital invested in the utility.

31 As a result, the amount of capital invested and attributed which becomes part of the rate base is extremely important to both the consumers and the utility. This has led to considerable litigation over valuations of items and designation of assets appropriately within the rate base. At the end of the day, the Commission has the final say on whether an asset is included, or not included, in the rate base. See: *Salt Caverns* at para 22; *Alberta Power Ltd. v. Alberta (Public Utilities Board)* (1990), 102 A.R. 353 (Alta. C.A.).

32 Arguments on appeal centered on this court's recent decisions in *Carbon* and *Salt Caverns*. *Carbon* dealt with issues arising from a gas storage facility at Carbon, Alberta, where the facility started out as a producing gas field and was converted to a storage reservoir. Eventually the facility was no longer required for gas storage and issues surrounding removal from the rate base were raised on appeal to this court. The Board had concluded that the Carbon storage facility played no role in the appellant's gas distribution system and its only present contribution was to generate revenue that would reduce rates. The Board noted that ordinarily revenue generation on a stand-alone basis would likely not satisfy the use or required to use test for inclusion in the rate base. It found, however, that the Carbon storage facility was unique, due to its historical role as both an operational part of the system and as a source of revenue from leasing of surplus capacity. As a result of this historical uniqueness, the Board included the Carbon facility within the rate base, notwithstanding its only use was for revenue generation.

33 This court found the Board's decision unreasonable. The court defined the question before the court as an "extricable question of law: whether revenue generation by the Carbon storage facility qualifies as a 'use' under the proper interpretation of the statute" (para 21). The court concluded that the phrase "used or intended to be used" to provide service are only those assets used in an operational sense and not merely used for revenue generation or accounting for the revenue.

34 *Carbon* found at para 29 that the concept of assets becoming "dedicated to service" and so remaining in the rate base forever is inconsistent with the decision in *ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board)*, 2006 SCC 4 (S.C.C.) at para 69, [2006] 1 S.C.R. 140 (S.C.C.) [the *Stores Block* decision] and would fetter the Board's discretion to deal with changing circumstances. In *Stores Block*, the Supreme Court of Canada found that regulation of the gas utility does not give the end customers an ownership interest in the assets of the utility.

35 At para 30 in *Carbon*, this court held:

> The end customers are entitled to service, not assets. The service that they are entitled to is the delivery of gas on reasonable and just terms, not revenue generation. Just as the end customers have no ownership interest in the assets of the utility, they have no interest in the profits, unregulated revenues, or unregulated businesses of the utility. The value of economic assets is often largely determined by the revenues they can generate, and if the end customers are not entitled to any ownership interest in the assets, they are likewise not entitled to any interest in the cash flow generated by those assets: *Store Block* at para 78. The end customers are entitled to receive gas delivery services from the utility, not revenue-generating services or gas rate subsidization.

36 In *Carbon*, no operational use existed, and the court found that mere revenue generation, or accounting for revenue, was not a service. As a result, the Board's decision to include the Carbon facilities in the rate base was found to be unreasonable.

37 In *Salt Caverns*, this court paraphrased from the *Carbon* decision at para 14:

> In any event, to the extent to which the answers to the legal issues raised in the first and second questions on which leave was granted are not premature, they are largely resolved by this court's recent decision in "*Carbon*" where the Court held that that the Board had no jurisdiction to include in rate base, assets which were not being used or required to be used in providing service to the public, in an operational context. Past or historical use of assets does not permit their inclusion in rate base unless they continue to be used in the system.

38 As a result of that language, the Commission and the respondent Utilities Consumer Advocate [UCA] argue that if there is no jurisdiction to include assets not being used in the utility operations, then prior orders that included such assets are a nullity. In my view, the court in *Salt Caverns* was not intending to expand upon the *Carbon* decision by use of the word jurisdiction, but was merely summarizing *Carbon* in a general way. I do not read *Carbon* as suggesting that this is a jurisdictional issue such that past orders of the Board which included assets of no operational use were a nullity. Rather, the court found accounting for revenue and revenue generation standing alone are not part of the utility service, and that they should not be included in the rate base.

39 The decision in *Salt Caverns* is important here. In that case, the court addressed the question of whether unilateral withdrawal of assets from utility service and the rate base was a "disposition" under section 26(2)(d), requiring commission approval. The court concluded that the scope of the language of section 26(2)(d) referred to giving up ownership, in whole or in part. It found that the words do not refer to starting or stopping a particular use, acquiring or losing a need, or to objects becoming useful or useless. In the end, the court found that the language did not apply to ending a use. Interestingly, in arriving at this decision the court stated at paras 51-53:

> So I interpret the words of s. 26 as not applying to ending a use. If that produced an absurd result, or crippled the Commission's power to regulate rates, then one might have to look harder at s. 26 and even try to stretch its words.
>
> But I see no *hiatus* here. It is common ground that as part of a normal rate hearing, the Commission can and must decide what items (property) are to be considered part of the rate base and given a value on which the utility company is entitled to recover a return on investment: s. 37 of the *Gas Utilities Act*. ...

> Indeed, counsel for the appellant stressed to us what the Commission could do when hearing a rate application if it found want of due prudence in starting or stopping the use of some asset in the regulated utility. It could make some adjustment of values in the rate base or in the expenses or return on investment, so that rates approved would not make the consumers pay rates based on that type of imprudence.

40 Determining usefulness will depend upon meeting the traditional criteria for what is, and what is not, in the rate base and does not involve a section 26 application because the property has not been disposed.

41 These authorities indicate that, at least on a go forward basis, assets no longer used or required for use should not be included in the rate base, and the utility can unilaterally remove such assets from the rate base without the consent of the Commission. But, at the end of the day, the Commission will have the final say on whether property is, or is not, required for the use or future use of the utility as that falls squarely within its legislative mandate. In addition, a commission has the right to make whatever adjustments are necessary to compensate for imprudent removal of such assets in the interim.

42 This reasoning was confirmed by McFadyen JA in *ATCO Gas South, Re*, 2010 ABCA 158, 487 A.R. 191 (Alta. C.A.). This was a leave to appeal application following the *Carbon* and the *Salt Caverns* decisions. In the *Calgary (City)* case, the Commission ordered assets removed from the rate base and adjustment to the rate base as of April 1, 2005, when the applicant had first indicated to the Commission that the asset was not used, or required to be used, in providing service to the public. The Commission backdated the removal of the asset from the rate base. In refusing to grant leave to appeal, McFadyen JA stated at para 23:

> Although the Commission may require that the utility prove that the asset is no longer being used in its operations, and that the cessation of use of the asset is not imprudent, absent proof of imprudence, **the adjustment date must be the date on which the utility, in fact, stopped using the asset, not the date on which the Commission agreed that the asset was no longer being used**.
>
> (Emphasis added.)

43 Atco asserts that the effective date for removal of surplus assets should be within 30 days of the decision on its application, regardless of the closing date of the surplus assets transaction. It says Atco was penalized for complying with the Commission's earlier express directions, and for the uncertainty created by the Commission's refusal to communicate acceptance that the assets should be removed from the rate base. Although the Commission had been acting on a misapprehension of the law, Atco says that does not alter the fact its assets were effectively frozen.

44 Atco says the facts in *Carbon* are distinguishable. In *Carbon*, the appropriate date for removal of assets was found to be the date management first determined the assets were not required for utility operations. In that case, however, the Commission authorized utilization of the assets for non-utility purpose pending determination of the issue. Thus, revenue was not lost in *Carbon*, whereas here, the Commission's directions resulted in no revenue from the non-utility assets. Atco argues that any date earlier than 30 days from the present decision without compensation yields an artificial, perverse result and is unreasonable.

45 Atco also submits that the principle against retroactive ratemaking should be mechanically applied, and that backdating the removal of the salt cavern assets to July 1, 2009, without using a deferral account or interim rate, is a violation of the principle against retroactive ratemaking. It says the Commission erred in law.

46 The respondent UCA takes a different position. It argues that the effective date for removal of the assets must be September 1, 2007, the date Atco first determined that the assets were no longer required for operational purposes. UCA argues once assets serve no utility purpose, there is no jurisdiction to retain them in the rate base and any decisions which included them are void. UCA says that since customers cannot share any revenues earned from assets with no valid operational purpose, nor share in any gain on the sale of such surplus assets, customers should not be forced to pay for assets once they are determined to be surplus. (See *Carbon* at para 30; *Stores Block* at para 69.) The UCA argues

that it is irrelevant if the assets were earning income to Atco's benefit, or incurring costs to its account, during this time. Rather, the only issue is whether the assets were being used or required for operations of the utility. If not, they should be excluded, and there was no jurisdiction to include the assets in the rate base from September, 2007.

47 The Commission was alive to and considered the arguments, and concluded that July 1, 2009 should be the effective date for removal of the Salt Cavern Excess Assets from utility service, rate base, revenue requirement and rates. Atco was directed to refund to customers all amounts collected through rates associated with those assets from and after that date. In arriving at its decision, the Commission considered the facts, the submissions and the law.

48 The Commission has broad, discretionary powers to set just and reasonable rates: *Gas Utilities Act*, sections 36 and 37. The Commission is required to balance the interests of the public while acting in a fair manner towards the utility. This regulatory compact between the Commission and Atco is well known:

> Under the regulatory compact, the regulated utilities are given exclusive rights to sell their services within a specific area at rates that will provide companies the opportunity to earn a fair return for their investors. In return for this right of exclusivity, utilities assume a duty to adequately and reliably serve all customers in their determined territories, and are required to have their rates and certain operations regulated.
>
> *Stores Block* at para 63

49 Discussing the statutory requirement to set just and reasonable rates, the Supreme Court of Canada noted:

> Rate regulation serves several aims — sustainability, equity and efficiency — which underlie the reasoning as to how rates are fixed:
>
> > ... the regulated company must be able to finance its operations, and any required investment, so that it can continue to operate in the future ... Equity is related to the distribution of welfare among members of society. The objective of sustainability already implies that shareholders should not receive "too low" a return (and defines this in terms of the reward necessary to ensure continued investment in the utility), while equity implies that their returns should not be "too high". (R Green and M Rodriguez Pardina, *Resetting Price Controls for Privatized Utilities: A Manual for Regulators* (1999), at 5)
>
> *Stores Block* at para 62

50 Fairness to customers requires that the rate base include only assets used or to be used for operation of the utility and not assets with no production value. At the same time, the Commission has an obligation of fairness to the utility. The Commission recognized the effect of its directions to Atco when it selected a July 1, 2009 implementation date.

51 I do not accept Atco's submission that the Commission erred in law by engaging in prohibited retroactive ratemaking. Whether a decision is impermissible retroactive ratemaking is an issue of fact. (See *ATCO Gas, Re*, 2010 ABCA 132, 477 A.R. 1 (Alta. C.A.), discussed below.) There are two fundamental policy concerns behind retroactive ratemaking. With regard to the utility, retroactive ratemaking is unfair because a utility relies on certain rates to make business decisions. To change them after the fact could cause unexpected results for the utility: Yvonne Penning, "Can Economic Policy and Legal Formalism Be Reconciled: The 1986 Bell Rate Case" (1989) 47 *U Toronto Fac L Rev* 607 at 610. With regard to consumers, retroactive ratemaking redistributes the cost of utility service by asking today's customers to pay for expenses incurred by yesterday's customers: "Can Economic Policy and Legal Formalism Be Reconciled" at 610. Clearly, that should be avoided.

52 In this case, removing the salt cavern assets from the rate base or revenue requirement would cause a decrease in rates and a benefit for customers, not an increase after the fact. Thus, retroactivity to July 1, 2009 works in favour of customers from that date forward. The question here involves the question of fairness to the utility.

53 Where a utility has knowledge that assets are not required for operational purposes, and knows it can unilaterally remove them, the utility must also be taken to know that the rates will be subject to change as a result of the non-inclusion of those assets in the rate base. It has the choice to remove the assets and utilize them in other revenue generating operations. Once there is knowledge, the harm of retroactive ratemaking from the utility's perspective vanishes.

54 Retroactive ratemaking was considered by this court in *ATCO Gas, Re*, 2010 ABCA 132, 477 A.R. 1 (Alta. C.A.) at paras 46-47 [*Deferred Gas Accounts* decision], where it confirmed the problems surrounding retroactive ratemaking by a regulatory authority:

> Generally, ratemaking and rates must be prospective: *Coseka Resources Ltd v Saratoga Processing Co* (1980), 31 A.R. 541 at para. 29, 16 Alta. L.R. (2d) 60 (C.A.). A utility's past financial results can be used to forecast future expenses, but a regulator cannot design future rates to recover past revenue deficiencies: *Northwestern Utilities Ltd., Re* (1978), [1979] 1 S.C.R. 684at 691 and 699 [*Northwestern Utilities*].
>
> Retroactive ratemaking "establish[es] rates to replace or be substituted to those which were charged during that period": *Bell Canada v. Canada (Canadian Radio-Television & Telecommunications Commission)*, [1989] 1 S.C.R. 1722 at 1749. Utility regulators cannot retroactively change rates because it creates a lack of certainty for utility consumers. If a regulator could retroactively change rates, consumers would never be assured of the finality of rates they paid for utility services.

55 The *Deferred Gas Accounts* decision of this court, following *Stores Block*, set down guiding principles for determining whether ratemaking was impermissibly retroactive.

56 Simply because a ratemaking decision has an impact on a past rate does not mean it is an impermissible retroactive decision. The critical factor for determining whether the regulator is engaging in retroactive ratemaking is the parties' knowledge. Hunt JA stated at para 57:

> Both *Bell Canada 1989* [*Bell Canada v Canada (Canadian Radio-Television and Telecommunications Commission)*, [1989] 1 SCR 1722] and *Bell Aliant* [*Bell Canada v Bell Aliant Regional Communications*, 2009 SCC 40, [2009] 2 SCR 764] (which concerned deferral accounts rather than interim rates) illustrate the same preoccupation: **were the affected parties aware that the rates were subject to change?** If so, the concerns about predictability and unfairness that underlie the prohibitions against retroactive and retrospective ratemaking become less significant. (Emphasis added.)

57 If a utility is aware that a rate is interim and subject to change, then a regulator's revision of the rate will not be disallowed for impermissible retroactive ratemaking. This was the conclusion reached by the Supreme Court of Canada in *Bell Canada v. Canadian Radio-Television & Telecommunications Commission*, [1989] 1 S.C.R. 1722, 60 D.L.R. (4th) 682 (S.C.C.) [*Bell Canada 1989*].

58 According to the Supreme Court of Canada in *Bell Canada* at 1756, alteration of an interim rate by a regulator is simply a function of regulators who have the mandate to ensure rates and tariffs are, at all times, just and reasonable.

59 In this appeal, the Commission expressly reserved the issue of the salt cavern assets, among others, from the revenue requirement determination: Commission's Decisions 2009-033 and 2010-228. Atco says the use of a placeholder (reserving the issue of the salt cavern assets for future determination) was not enough to enable the Commission to revisit the matter in subsequent years. Atco submits that the terms "interim rate order" and "deferral account" are well understood by all parties and that the use of the word "placeholder", without more, is not enough to achieve the same purpose as interim rates and deferral accounts. I do not agree. Atco had all the information it required by June 2009 to know that it was not entitled to revenue from inclusion of those assets in the rate base.

60 In 2009 and 2010, as permitted under the *Gas Utilities Act*, Atco engaged in negotiation of issues related to the salt cavern assets and revenue requirements. The resulting Negotiated Settlements in 2009 and 2010 expressly reserved making a decision about removing the salt cavern assets from the revenue requirement because the parties were addressing the matters in separate proceedings. The Negotiated Settlements (found in the Commission's Decision 2009-033 and Decision 2010-228) set Atco's revenue requirement for 2009 and 2010. Atco knew that the Negotiated Settlements only represented a partial rate, subject to the determination of the proceedings relating to the salt cavern assets. This is apparent when in 2010 the parties to the Negotiated Settlements agreed to not delay the rate setting proceedings for the sake of determining the fate of the salt cavern assets:

> In a letter dated January 22, 2010, the Commission agreed with all parties that the present proceeding should not be delayed as a result of any issues regarding the Identified Salt Cavern Assets. The Commission granted [Atco's] request to deal with the Identified Salt Cavern Assets in a separate, subsequent proceeding. Given that the removal of Identified Salt Cavern Assets would constitute a change to revenue requirement which would ultimately be reflected in a change to rates, the Commission considered that any such Identified Salt Cavern Assets proceeding would be a rate-setting proceeding.
>
> Decision 2010-228 at para 26

61 Not only did Atco agree to deal with the salt cavern assets in a separate proceeding, it was aware that the revenue requirement would change as a result of removal of the assets. Although there was no discussion about interim rates or deferral accounts, Atco had knowledge that the impact of the subsequent proceeding could result in a different revenue requirement. It not only can be taken to have known that it could remove the assets from the rate base, but the reservation of the issue of the salt cavern assets for a future proceeding certainly supports the Commission's finding here.

62 Slavish adherence to the use of interim rates and deferral accounts should not prohibit adjustments in a case such as this. Regulators have a broad, discretionary authority when ratemaking. The relevant question here is whether the utility knew from the actions or words of the regulator that the rates were subject to change. Atco clearly knew since 2007 that the identified salt cavern assets were not being used or required for operations of the utility. Atco's submission that a commission can only change rates if it used an interim rate or deferral account misapprehends the reason why deferral accounts and interim rates can be retrospectively altered by a regulator. The question here is not whether the regulator used the name "deferral accounts" or "interim rates" but whether Atco was aware that the rate could be altered retroactively.

63 The Commission recognized the problem it had created by refusing to allow removal of excess salt cavern assets and therefore elected not to set the date before July 1, 2009. It awarded Atco compensation on a *quantum meruit* basis for the period January 1, 2008 to June 2009. But by July 1, 2009, Atco not only knew the excess assets were not required for operations, it was aware it could unilaterally remove them. It could, at that time, have withdrawn the assets and utilized them prudently in any manner short of disposition as defined under section 26. As a result, it was Atco's decision to freeze the use of the assets by not unilaterally withdrawing them once *Salt Caverns* issued. It should have recognized that rates would change.

64 I reject the UCA's argument that it was a jurisdictional error not to order an implementation date of September 2007, when Atco first indicated the assets were no longer used or would be used for utilities services. Moreover, given the history of this matter, the uncertainty of the law, and the Commission's acceptance of its role in directing the assets not be removed, the Commission's choice of a later date is reasonable. The Commission was exercising its broad, discretionary power to set just and reasonable rates when it selected the implementation date as it is entitled to do.

65 In summary:

1. Assets not being used or required to be used for utility service are not to be included in the rate base; and

> 2. a utility has the responsibility to withdraw assets from the rate base once the assets are no longer used or required to be, and no Commission approval is required. Such removal is, of course, subject to a prudency review by the Commission.

This decision falls squarely within the Commission's mandate, it is not unreasonable and is owed deference by this court. The appellant has failed to show that the Commission erred in law or acted unreasonably in exercising its discretionary power, and this ground of appeal must be dismissed.

Issue 2: Did the Commission err by requiring Atco to bear the costs and burdens attributed to non-utility use of portions of a single, indivisible asset originally acquired for the purposes of the utility?

66 The Commission included the eastern portion of the undivided SE quarter of section 34, township 55, range 21-W4M in the assets found no longer used or required for providing utility service (the Additional Assets) and excluded them from the rate base. The Commission held that since no more salt caverns are to be developed, and the water pipeline is not necessary to maintain the existing caverns, then the Additional Assets should also be removed from the rate base. It is common ground that these assets are not required for operations, but Atco argues this quarter section is an undivided asset that should not be notionally divided for rate base purposes. The Commission rejected that argument and held that customers should not be burdened by the costs attributed to the unused portion of the land and well just because Atco chooses not to subdivide or use the land in some other manner.

67 The Commission held that subdivision of this quarter section is not required to remove part of the asset from the rate base, finding it could remove a proportional amount of the book value of the land and non-depreciable assets. It stated at para 100:

> [Atco] is free then to make whatever use of the Additional Assets and Related Assets it may wish to for its own purposes. Given that it is not necessary to subdivide the property to remove the value of the Additional Assets and the Related Assets from rate base and revenue requirement, the cost of any subdivision of the property which [Atco] may wish to pursue for its own purposes or to dispose of the property should be for the account of [Atco] shareholders.

Both the Additional Assets and unused infrastructure (the Related Assets) were to be removed from the rate base. In addition, the Commission agreed that if Atco wished to proceed with a subdivision of the eastern portion of the quarter section and dispose of that land, the Commission consented to such a disposition under section 26(2)(d) of the *Gas Utilities Act*, on the basis that the costs of any subdivision would be borne by Atco.

68 Atco says that the decision is unreasonable. It says that part of the asset is still required for the rate base, the asset has always been in the rate base, and the Commission cannot exclude a portion of an asset from the rate base without bearing the costs of such removal.

69 The issue here is unique in that Atco does not want to proceed with subdivision due to costs of that subdivision. It involves the removal from the rate base of a portion only of a legally undivided asset, namely, a quarter section of land already in the rate base. The quarter section is an undivided parcel of land originally acquired in the 1980s for the purpose of establishing salt caverns on its western half and ensuring sufficient land for further salt caverns to the east, if and when required. Since then, other storage methods negate the need for future salt caverns. The existing salt caverns located on the westerly portion of the SE 34-55-21-W4M continue to have use for future utility service, but the eastern half of the quarter section and the well located on that land have no further use or expected use in operations.

70 In its 2008-2009 General Rate Application and its earlier application, Atco had included the Additional Assets among those it sought to remove from the rate base, indicating that it wished to transfer the eastern portion of the quarter section to a non-utility affiliate, Atco Energy Solutions Ltd. This is notable as it is some evidence of an alternative use of this portion of land. By the 2011 application, the County of Strathcona had increased the development levy resulting in

subdivision costs estimated at $1.2 million. As a result, Atco said that its affiliate no longer had any interest in acquiring the land.

71 Atco takes the position that the quarter section is one indivisible asset acquired for utility purposes. As the asset is, and has historically been, used in operations and included in the rate base, it should remain there unless the cost of subdivision is borne by the ratepayers. Atco submits that the whole asset is properly in the rate base and the Commission cannot divide an undivided asset into portions for the purpose of excluding the value and costs associated with that portion from the rate base.

72 At a minimum, Atco says that if the Commission wants to separate the value and costs associated with the eastern half from the rate base that should be accomplished by a legal subdivision of the property, which, if directed by the Commission, should be a cost recoverable from ratepayers as the utility would not voluntarily incur such a cost.

73 I am satisfied that the Commission cannot order Atco to legally subdivide its quarter section of land. The authorities provide that an asset owned by a utility is the utility's private property. (See: *Stores Block*; *Salt Caverns*). While the Commission has the power under section 26 to block the sale of an asset in the rate base, it does not have the converse authority to interfere with property rights and order the sale of an asset. The Commission, therefore, cannot order the property be subdivided in order to treat the unused portion as no longer part of the rate base.

74 In *ATCO Gas, Re*, 2009 ABCA 171, 454 A.R. 176 (Alta. C.A.) [the *Harvest Hills* decision], this court considered the regulatory board's jurisdiction to appropriate proceeds of sale from lands not used nor required to be used to provide service. Relying on the *Stores Block* decision, this court held at para 29 there was no power to allocate proceeds from a sale or interfere with ownership rights where the asset is no longer needed to provide service to customers.

75 Nonetheless, the Commission can make decisions about assets in the rate base. It is mandated to fix just and reasonable rates pursuant to section 36 of the *Act*. In so doing, section 37 grants the Commission jurisdiction to determine the rate base and decide what assets are used or required to be used in providing utility service as described by this court in *Salt Caverns* at paras 28 and 31:

> Can it be reasonably argued that this regulatory power is confined to ruling on adding new items to the rate base, but inapplicable to excluding old or unused items? No. Phillips, [*The Regulation of Public Utilities* (Public Utilities Reports, 1992)] at 302 quotes another established textbook and lists items which regulatory commissions may exclude from the rate base. They include obsolete property, property to be abandoned, overdeveloped property and facilities for future needs, and property used for non-utility purposes.
>
> . . .
>
> The paragraphs above show that the rate-regulation process allows and compels the Commission to decide what is in the rate base, i.e. what assets (still) are relevant utility investment on which the rates should give the company a return. The traditional test is whether they are used or required to be used, and (as will be seen below) nothing in the legislation changes that.

76 The Commission is also required under section 37(2) to give due consideration to:

> (a) to the cost of the property when first devoted to public use and to prudent acquisition cost to the owner of the gas utility, less depreciation, amortization or depletion in respect of each, and
>
> (b) to necessary working capital.

77 Thus, the Supreme Court of Canada in *Stores Block* described the Board's responsibility as "maintaining a tariff that enhances the economic benefits to consumers and investors of the utility" (para 64). A commission must consider the symmetry of risk and return for both the utility and its customers. As stated by the majority in *Stores Block* at para 69:

> Assets are indeed considered in rate setting, as a factor, and utilities cannot sell an asset used in the service to create a profit and thereby restrict the quality or increase the price of service. Despite the consideration of utility assets in the rate-setting process, shareholders are the ones solely affected when the actual profits or losses of such a sale are realized; the utility absorbs losses and gains, increases and decreases in the value of assets, based on economic conditions and occasional unexpected technical difficulties, but continues to provide certainty in service both with regard to price and quality.

78 In addition, the Commission has discretion to act in the public interest when customers would be harmed or face some risk of harm. As described by the majority in *ATCO Ltd. v. Calgary Power Ltd.*, [1982] 2 S.C.R. 557 (S.C.C.), at 576:

> It is evident from the powers accorded to the Board by the legislature in both statutes mentioned above that the legislature has given the Board a mandate of the widest proportions to safeguard the public interest in the nature and quality of the service provided to the community by the public utilities. ... This no doubt has a direct relationship with the rate-fixing function which ranks high in the authority and functions assigned to the Board.

79 The Supreme Court of Canada in *Stores Block* held that while the Board could not allocate or appropriate sale proceeds, it had other options within its jurisdiction when a sale would affect the quality and/or quantity of the service offered by the utility or create additional operating costs for the future, such as not approving a sale. Additionally, the Board could attach conditions. The majority at para 77 suggested, "It could also require as a condition that the utility reinvest part of the sale proceeds back into the company in order to maintain a modern operating system that achieves the optimal growth of the system." But *Stores Block* also held that the ratepayers could not enjoy any of the profits of the sale, notwithstanding that through rates the ratepayers pay for or contribute to the acquisition of the asset.

80 In *Harvest Hills*, this court (at para 34) was of the view that the Board may impose conditions where it had a valid concern to guard against land speculation.

81 Similarly, in *Salt Caverns*, this court considered the possibility of a commission adjusting values of property in the rate base where it had a concern that the use or disuse of some asset lacked prudence. It stated at paras 52-53:

> It is common ground that as part of a normal rate hearing, the Commission can and must decide what items (property) are to be considered part of the rate base and given a value on which the utility company is entitled to recover a return on investment: s. 37 of the *Gas Utilities Act*. ...

> Indeed, counsel for the appellant stressed to us what the Commission could do when hearing a rate application if it found want of due prudence in starting or stopping the use of some asset in the regulated utility. It could make some adjustment of values in the rate base or in the expenses or return on investment, so that rates approved would not make the consumers pay rates based on that type of imprudence.

82 *Harvest Hills* focussed on the issue of disposition of land that had already been subdivided, so division was not contested. In this case, the Commission authorized a disposition under section 26(2)(d), but did not order the land divided. Rather, it removed the value it attributed to the eastern portion of the quarter section no longer required for utility service purposes. In doing so, it was determining the rate base including the property still in use for utility service pursuant to section 37, as it is entitled to do. Atco was free to use that substantial portion of land as it saw fit. There was no evidence suggesting it had no alternative uses.

83 The parties did not direct the court to any authority governing principles surrounding the removal of a portion of an asset from the rate base. In my view, those principles should be developed incrementally. While I recognize the general principle that assets which cease to have a utility purpose should be withdrawn from the rate base, the question still remains: "what is the asset?" Considerations for the Commission will vary with the facts and circumstance of the case, and in particular, the nature of the asset. Depending on the facts, the decision to remove a portion of an asset from the rate base may raise many considerations, including such matters as whether an asset can be physically, practically

or legally divided; ease of division; associated costs involved and who should pay them; length of time the asset was in the rate base; whether the divided portion has other potential uses; whether separation of part of an asset sterilizes the remainder; and in general, what is just and reasonable in the circumstances. The list is neither definitive of factors to be considered, nor will every case require consideration of all criteria. The fact situation could vary from an easily divisible asset to a physical plant where the portion not required for operational use has no other functional purpose, yet costs associated with the unused and unneeded portion. Is an undivided plant two assets for the rate base purposes?

84 In this case, the land had been in the rate base since 1982. As a result the utility had received a return on its investment for some time. The parties were in agreement that the eastern portion of this land and the well were not needed for the operations of the utility. Could it have other uses? The asset here is a tract of land. The Commission concluded that Atco was free to engage in other uses for the unused portion of land, if it chose not to sell. No evidence suggested that this land had no other use, short of subdivision and sale, nor that the eastern portion of the quarter section (some 80 acres) would be sterilized for other use so long as the western portion remained in the rate base. Indeed, Atco's earlier application for approval to remove for sale to a related company is evidence supporting a finding of other uses.

85 Atco sought, at a minimum, that the subdivision costs be borne by the ratepayers but the Commission was not prepared to place that burden on the ratepayers. It authorized other uses, obviously concluding that subdivision was unnecessary for all uses.

86 Since the authorities have established that ratepayers cannot share in any of the sales of assets, it follows that holding property within the rate base, once its use has expired, works to the detriment of the ratepayer. The recent principles set down in *Stores Block* and *Carbon* make it clear that ratepayers have no opportunity to share in the better times when land values rise, so it is important to protect the ratepayer by ensuring only proper assets remain in the rate base. In judging reasonableness, it is important to remember that since ratepayers cannot share in sale proceeds of utility assets, their protection for fair treatment lies in excluding assets not required for utility operations from the rate base.

87 Other choices for dealing with this quarter section might have been selected by the Commission. For example, perhaps the Commission could have elected to keep the whole asset in the rate base and ensure prudent non-utility use of the eastern half and share in that revenue because the asset remains in the rate base. While the authorities suggest that an asset cannot be kept in the rate base for the purpose of earning non-utility revenue, those cases were dealing with assets no longer required for utility purposes. I do not read the authorities as denying flexibility where a portion of an asset is required for utility operations and removal of the balance of the asset is not just or reasonable. I do not need to make that decision here in view of the Commission's decision to remove value of the eastern half from the rate base.

88 The Commission obviously considered the eastern portion and the balance of the quarter section as two assets for rate purposes. That decision is a reasonable one on the facts of this case.

89 In summary:

1. Fair treatment for ratepayers requires exclusion of assets not required for utility operations from the rate base.

2. The standard of review of a commission's decision to remove an asset from the rate base is one of reasonableness.

3. The Commission's decision to treat the quarter section of land as two assets for the rate base purposes and direct the utility to remove the costs of the non-utility use portion from the accounting determination of the rate base and revenue requirement was not unreasonable on the facts and circumstances here, and I see no basis for appellate intervention.

Conclusion

90 The appeal is dismissed.

***Peter Martin J.A.*:**

I concur:

***Ronald Berger J.A.* (Concurring):**

91 I have had the advantage of reading in draft form the Reasons for Judgment Reserved of Conrad J.A. of November 22, 2013.

92 Application of the principles that emerge from the reported cases cited by counsel support dismissal of the appeal. They are the following:

1) Section 37 of the ***Gas Utilities Act***, RSA 2000, G-5 requires an asset to have an operational purpose in providing utility services to be included within the rate base. The cost of assets without an operational purpose in providing service to the public cannot be included in the rate base and in customer rates.

2) Section 26 of the ***Gas Utilities Act*** does not require the consent of the Commission prior to a utility removing an asset from the rate base.

3) It follows that a utility may, without obtaining prior Commission approval, remove an asset from the rate base at the time that the utility management considers that the asset is no longer used or required to be used, or will soon become no longer used or required to be used, in an operational sense to provide regulated utility services.

4) The Commission has no jurisdiction to include in the rate base assets which are not being used or required to be used in providing service to the public in an operational context: *ATCO Gas South, Re*, 2008 ABCA 200, 433 A.R. 183 (Alta. C.A.) (the "***Carbon*** decision"); *ATCO Gas & Pipelines Ltd. v. Alberta (Utilities Commission)*, 2009 ABCA 246, 464 A.R. 275 (Alta. C.A.) (the "***Salt Caverns*** decision"). See also the comments of McFadyen J.A. in *ATCO Gas South, Re*, 2010 ABCA 158, 487 A.R. 191 (Alta. C.A.).

[I appreciate full well that my colleague takes a different view with respect to the use of the term "jurisdiction" in this context. With great respect, I prefer the commentary of Jones and Villars, *Principles of Administrative Law*, 5th ed. (Edmonton: Carswell, 2009) at p. 149 on the issue of when a decision is *ultra vires* and void:

> "The question sometimes arises whether an *ultra vires* act is void or merely voidable. The answer is important in order to determine whether the delegate's action has any legal effect prior to the declaration by the court that it is *ultra vires*. In principle, all *ultra vires* administrative actions are void, not voidable, and there are not degrees of invalidity ... Although people may have acted on the assumption that the delegate did have authority to do the impugned action, the effect of the court's granting of judicial review must be to declare that that was an erroneous state of affairs, that the delegate never has jurisdiction to do the particular action in the manner complained of." (footnotes omitted)

After all, review by this Court is confined to errors of law or jurisdiction thereby limiting the Court to a determination as to whether actions of the inferior tribunal are void.]

5) When the assets cease to have a utility purpose, the utility is obliged to withdraw the assets from regulated service without first obtaining Commission approval.

6) The Commission has no jurisdiction over non-utility assets that are located within a single indivisible quarter-section of land originally acquired for the purposes of the utility when it would not have such jurisdiction if the non-utility assets were physically separated from utility assets.

7) It is not open to the Commission to compel the utility to physically sub-divide a quarter-section in order for the Commission to determine that customers should not be obligated to pay for non-utility assets located within that quarter-section.

8) When assets no longer have an "operational purpose" within the meaning of paras. 25 and 27 of the ***Carbon*** decision and paras. 14 and 56 of the ***Salt Caverns*** decision, it is open to the Commission to direct the utility to remove the cost of the additional assets and the related assets from the regulatory accounting determination of rate base, revenue requirement and customer rates.

9) It is the utility and its shareholders that must bear the burden of any losses on disposition of an asset and any decrease in value in property originally acquired by the utility to provide utility service. (See para. 69 of *ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board)*, [2006] 1 S.C.R. 140 (S.C.C.)). In other words, the cost of any sub-division of the property or its disposition is for the account of the utility's shareholders. (My colleague would afford the Commission some latitude. Given the statutory framework, I would not. The utility alone absorbs losses and gains).

93 In concurring in the result, I find it unnecessary to comment further on the fulsome reasons of my colleague.

Appeal dismissed.

Most Negative Treatment: Distinguished
Most Recent Distinguished: ENMAX Power Corp., Re | 2014 CarswellAlta 618, [2014] A.W.L.D. 2413, [2014] A.W.L.D. 2414 | (Alta. U.C., Apr 15, 2014)

2010 ABCA 132
Alberta Court of Appeal

ATCO Gas, Re

2010 CarswellAlta 764, 2010 ABCA 132, [2010] A.W.L.D. 2377, [2010] A.W.L.D. 2380, [2010] A.J. No. 449, 188 A.C.W.S. (3d) 567, 26 Alta. L.R. (5th) 275, 318 D.L.R. (4th) 615, 477 A.R. 1, 483 W.A.C. 1

City of Calgary (Appellant / Applicant) and Alberta Energy and Utilities Board (Respondent / Respondent) and ATCO Gas and Pipelines Ltd. (Respondent / Respondent)

Jean Côté, Constance Hunt, Marina Paperny JJ.A.

Heard: January 13, 2010
Judgment: April 23, 2010
Docket: Calgary Appeal 0801-0030-AC

Proceedings: reversing *ATCO Gas, Re* (2008), 2008 CarswellAlta 2238 (Alta. E.U.B.); and reversing *ATCO Gas, Re* (2005), 2005 CarswellAlta 2255 (Alta. E.U.B.)

Counsel: B.J. Meronek, Q.C. for Appellant / Applicant, City of Calgary
J.P. Mousseau, P. Khan for Respondent / Respondent, A.E.U.B.
H.M. Kay, Q.C., L.E. Smith, Q.C., L.A. Goldbach for Respondent / Respondent, ATCO Gas and Pipelines Ltd.

Subject: Public; Civil Practice and Procedure
Related Abridgment Classifications
Public law
IV Public utilities
  IV.2 Operation of utility
    IV.2.d Rates
      IV.2.d.iii Approval
Public law
IV Public utilities
  IV.5 Regulatory boards
    IV.5.c Practice and procedure
      IV.5.c.iii Statutory appeals
        IV.5.c.iii.B Grounds for appeal
          IV.5.c.iii.B.1 Lack of jurisdiction
Headnote
Public law --- Public utilities — Operation of utility — Rates — Approval
In 2004, gas company sought approval of Alberta Energy and Utilities Board to correct balances in its deferred gas account ("DGA") because actual gas costs company incurred from January 1999 to February 2004 had been understated — Adjustment was sought because there had been inaccurate reporting of gas being transported for other entities through company's pipeline network — Company proposed that its present consumers would pay shortfalls for prior period —

Board permitted company to recover 85 percent of amounts through adjustments to DGA — In subsequent decision, board found that it had jurisdiction to grant company's application — City appealed — Appeal allowed; matter referred to board for reconsideration — Board's decision to allow the company to recover 85 percent of transportation imbalances through DGA was unreasonable — Board's authority over DGAs flowed from its power to set just and reasonable rates and fair rate of return on rate base found in ss. 36 and 37 of Gas Utilities Act — Unlike most previous uses of DGAs, charges did not result from gas price volatility — Failure to levy appropriate gas charges was entirely due to deficiencies within company's own system, exacerbated by long delay in discovering problem — Company's destruction of data made data verification impossible — As result of delays, at least some who were not consumers when problems originated would have to absorb costs of company's carelessness — Even though this was not prohibited ratemaking, long delays gave rise to inter-generational equity issues which were at heart of prohibition against retrospective ratemaking.

Public law --- Public utilities — Regulatory boards — Practice and procedure — Statutory appeals — Grounds for appeal — Lack of jurisdiction

In 2004, gas company sought approval of Alberta Energy and Utilities Board to correct balances in its deferred gas account ("DGA") because actual gas costs company incurred from January 1999 to February 2004 had been understated — Adjustment was sought because there had been inaccurate reporting of gas being transported for other entities through company's pipeline network — Company proposed that its present consumers would pay shortfalls for prior period — Board criticized company for design errors in its information system report and its delay in detecting them — Board permitted company to recover 85 percent of amounts through adjustments to DGA — In subsequent decision, board found that it had jurisdiction to grant company's application — City appealed — Appeal allowed on other grounds — Board was allowed to authorize use of DGAs — Board's authority over DGAs flowed from its power to set just and reasonable rates and fair rate of return on rate base found in ss. 36 and 37 of Gas Utilities Act.

In 2004, a gas company sought the approval of the Alberta Energy and Utilities Board to correct balances in its deferred gas account (DGA) because actual gas costs the company incurred from January 1999 to February 2004 had been understated by $11.6 million. The adjustment was sought because there had been inaccurate reporting of gas being transported for other entities through the company's pipeline network. The company proposed that its present consumers would pay the shortfalls for the prior period.

The board criticized the company for the design errors in its information system report and its delay in detecting them, but permitted the company to recover 85 percent of the amounts it sought through adjustments to its DGA. In a subsequent decision, the board found that it had the jurisdiction to grant the company's application.

The city appealed.

Held: The appeal was allowed. The matter was referred to the board for reconsideration.

Per Hunt J.A. (Paperny J.A. concurring): The board was allowed to authorize the use of DGAs. Deferral accounts allowed utilities to accumulate variances between a utility's approved rate based on forecasted costs and the utility's actual costs for a given period. The board's authority over DGAs flowed from its power to set just and reasonable rates and a fair rate of return on rate base found in ss. 36 and 37 of the Gas Utilities Act.

The proposed accounting adjustments had retrospective effect because past costs would be borne by the company's present consumers. Imposing gas cost shortfalls or surpluses incurred by past consumers on future consumers was generally prohibited. However, the history of DGAs demonstrated that affected parties knew they would be used from time to time to alter gas rates based on later, actual gas costs. The objective was to ensure that the consumer paid the actual cost of the gas. Therefore, the use of the DGA in this case did not involve prohibited ratemaking.

The board's decision to allow the company to recover 85 percent of the transportation imbalances through the DGA was unreasonable. Unlike most previous uses of DGAs, these charges did not result from gas price volatility. The failure to levy appropriate gas charges was entirely due to deficiencies within the company's own system, exacerbated by a long delay in discovering the problem. The company's destruction of data made data verification impossible. As a result of the delays, at least some who were not consumers when the problems originated would have to absorb the costs of the company's carelessness. Even though this was not prohibited ratemaking, the long delays gave rise to inter-generational equity issues which were at the heart of the prohibition against retrospective ratemaking.

Per Côté J.A. (concurring): The appeal should be allowed and so much of the board's orders vacated as allowed the recovery of former costs or expenses. The board made a clear and unreasonable error of law. The charge to customers to reimburse the company for its various accounting deficiencies was illegal retroactive rate-making. It was based on events long before the beginning of the fiscal year of the application, which contravened the legislation. The legislative history showed that only shortfalls or excesses of revenues and costs back to the beginning of the fiscal year in which the application was filed could be considered. The rates were final and the DGAs were reconciled years before. The DGAs were never intended nor ordered to be used for the purpose put forward by the company. The errors were from lax accounting, discovered belatedly. The board did not discuss the implications of the fact that this was basically cost-plus charges, not the fixing of rates. The board also shuffled the risk of shortfalls in profit onto consumers from the shareholders.

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Edmonton (City) v. Northwestern Utilities Ltd. (1961), 34 W.W.R. 600, 82 C.R.T.C. 129, 28 D.L.R. (2d) 125, [1961] S.C.R. 392, 1961 CarswellAlta 25 (S.C.C.) — considered

Epcor Generation Inc. v. Alberta (Energy & Utilities Board) (2003), 346 A.R. 281, 320 W.A.C. 281, 2003 CarswellAlta 1813, 2003 ABCA 374 (Alta. C.A.) — distinguished

Germain v. Saskatchewan (Automobile Injury Appeal Commission) (2009), 2009 CarswellSask 176, 2009 SKQB 106, [2009] 7 W.W.R. 509, (sub nom. *Germain v. Automobile Injury Appeal Commission*) 333 Sask. R. 116, 71 C.C.L.I. (4th) 185, 82 M.V.R. (5th) 234 (Sask. Q.B.) — considered

Kin Franchising Ltd. v. Donco Ltd. (1993), 7 Alta. L.R. (3d) 313, 14 C.P.C. (3d) 193, 1993 CarswellAlta 264 (Alta. C.A.) — considered

Newfoundland (Board of Commissioners of Public Utilities), Re (1998), 1998 CarswellNfld 150, (sub nom. *Reference re s. 101 of the Public Utilities Act (Nfld.)*) 164 Nfld. & P.E.I.R. 60, (sub nom. *Reference re s. 101 of the Public Utilities Act (Nfld.)*) 507 A.P.R. 60 (Nfld. C.A.) — distinguished

Northwestern Utilities Ltd., Re (1976), 1976 CarswellAlta 201, 2 A.R. 317 (Alta. C.A.) — considered

Northwestern Utilities Ltd., Re (1978), (sub nom. *Northwestern Utilities Ltd. v. Edmonton (City)*) [1979] 1 S.C.R. 684, (sub nom. *Northwestern Utilities Ltd. v. Edmonton (City)*) 7 Alta. L.R. (2d) 370, (sub nom. *Northwestern Utilities Ltd. v. Edmonton (City)*) 12 A.R. 449, (sub nom. *Northwestern Utilities Ltd. v. Edmonton (City)*) 89 D.L.R. (3d) 161, (sub nom. *Northwestern Utilities Ltd. v. Edmonton (City)*) 23 N.R. 565, 1978 CarswellAlta 141, 1978 CarswellAlta 303 (S.C.C.) — followed

Statutes considered by *Constance Hunt J.A.*:

Alberta Energy and Utilities Board Act, R.S.A. 2000, c. A-17

Generally — referred to

s. 15(1) — considered

s. 15(3)(a) — considered

s. 15(3)(d) — considered

s. 15(3)(e) — considered

s. 26(1) — considered

Gas Utilities Act, S.A. 1960, c. 37

Generally — referred to

s. 27 — considered

s. 27(a) — considered

s. 28 — considered

s. 28(1) — considered

s. 31 — considered

Gas Utilities Act, R.S.A. 2000, c. G-5

Generally — referred to

s. 36 — considered

s. 36(a) — considered

s. 36(e) — considered

s. 37(1) — considered

s. 38(1) — considered

s. 38(2) — considered

s. 40 — considered

s. 40(a)(i) — considered

s. 40(a)(ii) — considered

s. 40(a)(iii) — considered

s. 40(c) — considered

s. 40(d) — considered

Public Utilities Act, R.S.A. 1955, c. 267

s. 67(a) — considered

Public Utilities Act, R.S.A. 2000, c. P-45

Geneally — referred to

s. 36(1)(a) — referred to

s. 36(2) — referred to

s. 67(1) — considered

s. 67(2) — considered

s. 67(8) — considered

s. 89(a) — referred to

Statutes considered by *Jean Côté J.A.*:

Alberta Energy and Utilities Board Act, R.S.A. 2000, c. A-17

Generally — referred to

Alberta Utilities Commission Act, S.A. 2007, c. A-37.2

s. 11 — referred to

s. 29(1) — considered

s. 29(10) — considered

Gas Utilities Act, S.A. 1960, c. 37

Generally — referred to

s. 31 — considered

Gas Utilities Act, R.S.A. 1970, c. 158

s. 31 — referred to

Gas Utilities Act, R.S.A. 1980, c. G-4

s. 32 — referred to

Gas Utilities Act, R.S.A. 2000, c. G-5

Generally — referred to

s. 40 — referred to

s. 40(a)(i) — considered

s. 40(a)(ii) — considered

s. 40(b) — considered

s. 40(c) — considered

Public Utilities Act, R.S.A. 2000, c. P-45

Generally — referred to

s. 67(8) — considered

Railway Act, R.S.C. 1985, c. R-3

Generally — referred to

Telecommunications Act, S.C. 1993, c. 38

Generally — referred to

s. 7(a) — considered

s. 7(c) — considered

s. 7(d) — considered

s. 7(e) — considered

s. 7(f) — considered

s. 7(g) — considered

s. 7(h) — considered

s. 7(i) — considered

s. 35(1) — referred to

s. 42(1) — referred to

s. 46.5(1) [en. 1998, c. 8, s. 6] — considered

s. 47(a) — considered

Rules considered by *Jean Côté J.A.*:

Alberta Rules of Court, Alta. Reg. 390/68

R. 537.1 [en. Alta. Reg. 97/2008] — considered

APPEAL by city from decisions reported at *ATCO Gas, Re* (2008), 2008 CarswellAlta 2238 (Alta. E.U.B.) and *ATCO Gas, Re* (2005), 2005 CarswellAlta 2255 (Alta. E.U.B.).

***Constance Hunt J.A.*:**

1 I agree with Côté J.A. that the orders under appeal should be vacated, but reach that conclusion for different reasons. I would allow the appeal and return the matter to the Alberta Utilities Commission ("Board [1] ") for reconsideration in accordance with this judgment.

Facts

History of Deferred Gas Accounts (DGA)

2 The modern origin of deferred gas accounts (formerly deferred gas accounting) ("DGA") is a 1988 decision which arose out of a utility's general rate application: *Northwestern Utilities Ltd., Re* [(March 18, 1988), Doc. E88018 (Alta. E.U.B.)], In the matter of an application to determine rate base and fix a fair return thereon for the test years 1987 and 1988, Decision E88018, (Public Utilities Board). The use of a DGA was proposed to deal with seasonal price differences in gas costs. It required segregating the sales rate into two components, gas and non-gas. The latter would be determined in a general rate application while the former, the Gas Cost Recovery Rate ("GCRR"), would be determined twice a year using a formal filing process, subject to Board monitoring or review by way of a hearing. Adjustments to actual and estimated costs of gas would be held in the DGA then reconciled for refund to or recovery from consumers.

3 In approving these procedures, the Board emphasized that the outcome would be "customers pay for no more or less than the price of gas actually incurred ... the shareholders would not gain or be penalized as a result of price variations ...": p. 325. The use of a DGA would be beneficial to customers: p. 326. The Board described the GCRR's gas cost component as "interim": p. 327. This early decision demonstrates that the Board intended to scrutinize the use of the DGA on an ongoing basis.

4 The principles from this decision were applied the same year to Canadian Western Natural Gas Company Limited, the respondent ATCO's predecessor: *Re Canadian Western Natural Gas Company Limited*, In the matter of an Application by Canadian Western Natural Gas Company Limited for approval of Deferred Gas Accounting and Reconciliation

procedures respecting its gas supply costs, Order E88019, (Public Utilities Board, 1988). The DGAs at issue here were then created.

5 In 2001 ATCO and the appellant City of Calgary (Calgary) were both parties to a hearing that considered, *inter alia*, the methodology for determining the GCRR: Methodology for Managing Gas Supply Portfolios and Determining Gas Cost Recovery Rates (Methodology) Proceeding and Gas Rate Unbundling (Unbundling) Proceeding, Part A: GCRR Methodology and Gas Rate Unbundling. Decision 2001-75 (Alberta Energy and Utilities Board, 2001). Its context was the transition to competitive retail gas service. The Board noted its general supervisory power over utilities and its power to fix just and reasonable rates as the basis of its authority to deal with the issues in the hearing: p. 10.

6 The Board described "GCRR/DGA Programs" as follows at p. 56:

> The effect of a Gas Cost Recovery Rate/Deferred Gas Account (GCRR/DGA) mechanism is to spread the cost of gas acquisition and management over a forecast period, keeping consumer gas prices stable during that period. <u>The use of a DGA to keep track of differences between actual and forecast gas costs ensures that customers pay no more and no less than actual costs incurred on their behalf</u>. However, the reconciliation between forecast and actual costs occurs over one or more seasons. [footnote omitted] During periods of rapid gas price increase, as experienced in the winter of 2000/2001, the accumulated balances in the DGA can become large. The current system of GCRRs/DGAs has defined tolerance limits on the size of the DGAs, requiring the utilities to file for gas rate adjustments when the variance between forecast and actual costs becomes too large.
>
> [emphasis added]

7 The Board determined that utilities no longer needed to "file formal GCRR applications with the Board, but would instead file ... on a monthly basis", and monthly adjustments would be made to the GCRR: p. 64. Interested parties would have an opportunity to raise concerns about the monthly GCRRs filed by the utilities. Reconciliation of DGA balances would be done on a three-month rolling basis. The Board set a date for the commencement of this system, "in conjunction with the revised interim rates noted elsewhere in this Decision": p. 64.

8 Since then, the use of DGAs has evolved. For example, in ATCO Gas South Jumping Pound Meter Station - Gas Measurement Adjustment Application No. 1314487, Decision 2004-013, the Board approved adjustments to an ATCO DGA balance to reflect measurement errors caused by equipment malfunction. Part of the Board's rationale was that the adjustment was made in accordance with approved DGA procedures. A related adjustment to the DGA (timing costs) was rejected by the Board because it was not a previously approved DGA adjustment.

9 In other DGA decisions, the Board considered factors such as the amount of the adjustment, the timeliness of the application, whether the utility had acted responsibly, the foreseeability of the problem, and whether consumers who received the service were bearing the cost of the adjustment, see e.g., Northwestern Utilities Limited, 1996/1997 Winter Period Gas Cost Recovery Rate, [*Northwestern Utilities Ltd., Re*, 1997 CarswellAlta 1334 (Alta. E.U.B.)] Decision U97053 97053; IN THE MATTER of a Gas Cost Recovery Rate Refund for the 2001 Summer Period for AltaGas Utilities Inc. Order U2001-316 [*AltaGas Utilities Inc.* (November 29, 2001), Doc. U2001-316 (Alta. E.U.B.)].

Origin of this Dispute

10 In May 2004, ATCO sought Board approval to correct balances in the DGAs for each of its south and north gas distribution service territories. The proposed adjustment to the DGA for northern Alberta was largely attributable to *overstated* gas costs from January 1998 to February 2004, whereas in southern Alberta the actual gas costs ATCO incurred from January 1999 to February 2004 were *understated*. ATCO proposed that its present southern Alberta consumers would pay the shortfalls and that it would refund excesses to its present northern Alberta consumers. Since this appeal concerns only the adjustment proposed to the southern DGA, I make no further reference to the northern DGA.

11 The adjustments were sought because there had been inaccurate reporting of gas being transported for other entities through ATCO's pipeline network ("transportation imbalances"). It appears the errors began when the administration of ATCO's gas transportation system was moved to a new system, the transportation information system ("System").

12 ATCO had included the transportation imbalances as prior period adjustments in the DGA as part of its December 2003 GCRR filings. While producing supplementary information requested by the Board, ATCO detected additional transportation imbalances. It then refiled its December 2003 GCRR *excluding* the transportation imbalance adjustments. ATCO engaged chartered accountants to review its re-calculation of the imbalances. The Board's treatment of ATCO's subsequent application to record the revised transportation imbalances in the DGA is at the root of this appeal.

Board Decisions

13 Three Board decisions are relevant. Each is described in more detail beginning at para. 16.

14 The first decision partly allowed ATCO's application to use the DGA/GCRR reconciliation process to record the transportation imbalances: ATCO Gas, A Division of ATCO Gas and Pipelines Ltd. Imbalance and Production Adjustments - Deferred Gas Account Application No. 1347852, Decision 2005-036, ("DGA Decision"). In the second, the Board established a general rule that the DGA/GCRR reconciliation process has a two-year limitation period: ATCO Gas, A Division of ATCO Gas and Pipelines Ltd., Deferred Gas Account Limitation Period, Decision 2006-042 ("Limitations Decision"). The third focused on the Board's jurisdiction to make the DGA and the Limitations Decisions: ATCO Gas, A Division of ATCO Gas and Pipelines Ltd. Reconsideration of Decision 2005-036 Deferred Gas Account, Imbalance and Production Adjustments, Application No. 1524763 Proceeding ID. 5, Decision 2008-001 ("DGA Reconsideration Decision).

15 As to the DGA and DGA Reconsideration Decisions, Calgary obtained leave to appeal on the following question: "Whether the Board erred in law or in jurisdiction by allowing for the recovery, in 2005, of costs or expenses that were incurred between 199[9] [2] and 2004.": *ATCO Gas, Re*, 2009 ABCA 150 at para. 9, (Alta. C.A.). ATCO has discontinued its application for leave to appeal the Limitations Decision.

DGA Decision (Decision 2005-036)

16 The Board defined the central issue as "whether or not it is appropriate for the DGA to be a vehicle of all and any updates and corrections other than for price and actual gas sales (or deliveries)": p. 10.

17 In reviewing the history of the DGA/GCRR process, the Board noted that the DGA/GCRR process was originally approved to provide a method for adjusting for gas price volatility and that, by April 2002, the process was refined so that monthly (not seasonal) reconciliations were made: p. 10. Over time, DGAs were used without complaint to adjust gas rates for reasons unrelated to price volatility, including measurement corrections. While it had become a "relatively common occurrence" for DGAs to be used for making prior period adjustments, most were made "within a reasonable time period": *Id.*

18 The Board was troubled by the evolution of DGAs into a 'catch all' method for fixing all possible gas cost errors and by the timing of the adjustments. It criticized ATCO for the design errors in the System report and its delay in detecting them, reinforcing its expectation that ATCO's internal controls should detect material errors in a timely way.

19 Notwithstanding these misgivings, the Board permitted ATCO to recover eighty-five percent of the amounts it sought through adjustments to its DGA.

Limitations Decision (Decision 2006-042)

20 The Board's concerns about ATCO's delay in applying for the imbalance adjustments led to a hearing to examine whether it ought to impose a general policy limiting the extent to which adjustments are made to DGAs.

21 In the resulting Limitations Decision, the Board considered its jurisdiction to establish limitation periods for the DGA/GCRR process in the context of its statutory mandate to set just and reasonable rates and court decisions approving their use. It concluded that setting the GCRR requires the use of DGAs. Moreover:

> the deferral nature of the DGAs is specifically contemplated and acknowledged when the rates are set. Deferral accounts, by their nature, anticipate adjustments such as the ones at issue in this matter and, as such, cannot be said to constitute retroactive rate-making. The Supreme Court of Canada has approved the use of deferral accounts for gas and has further noted that such a mechanism is a purely administrative matter [citation omitted]. In *EPCOR Generation Inc. v. AEUB*, 2003 ABCA 374, the Alberta Court of Appeal adopted the same approach and stated that as the deferral account in issue in that decision was not closed, it was not a final order, and was not retroactive rate making or procedurally unfair.
>
> Consequently, the Board considers that a DGA has not been subject to any limitation regarding jurisdiction either by way of legislation, past Board decision or court ruling which would have prevented the Board from considering prior period adjustments to a DGA. In fact the Board has dealt with prior period adjustments to DGAs since their inception in 1987, with the prior periods being of varying lengths.
>
> p. 4 (emphasis added).

22 The Board adopted a general limitation period of two years prior to the effective date of the proposed GCRR for refunds to and recoveries from consumers. It permitted applications for approval of an adjustment to the DGA, where the cause of the adjustment originates outside the two-year limitation period, provided the following conditions are met:

> (a) the adjustment sought exceeds the threshold value by being greater than 5% of the average monthly DGA gas commodity costs of the previous 12 months; and
>
> (b) the adjustment arose from special circumstances that were not within the utility's control.

p. 17

23 As regards possible 'inter-generational equity' issues (a concept discussed more fully at para. 48 that means utility consumers should pay the costs associated with *their* consumption of the service, and future consumers should not benefit from or be burdened by the cost of services consumed by past consumers), the Board said at p. 12:

> While intergenerational equity questions ... arise ... particularly in relation to deferral accounts, the Board believes in this case that the imposition of a limitation period for DGAs assists in addressing the intergenerational issue raised ... because it limits the adjustments in the ordinary course. [ATCO] is correct in pointing out that deferred accounts have an inherent intergenerational aspect; however, the Board considers that it is important to not allow too long a period before dealing with adjustments.
>
> [emphasis added]

DGA Reconsideration Decision (Decision 2008-001)

24 Calgary was granted leave to appeal the DGA Decision on the question of whether the Board was authorized under its governing legislation to approve any of the adjustments to the Deferred Gas Account applied for by ATCO Gas. Following a hearing, this Court concluded that since the issue of the Board's jurisdiction to grant ATCO's May 2004 application had not been raised before the Board, the evidentiary record necessary for an appeal was lacking: *ATCO Gas, Re*, 2007 ABCA 133, 404 A.R. 317 (Alta. C.A.). The Court returned the matter to the Board, which then considered whether it was "authorized under its governing legislation to approve adjustments to the ATCO Gas DGA in 2005 for costs and expenses incurred between 199[9] and 2004": p. 2.

25 Calgary argued that the Board's jurisdiction was limited by section 40 of the *Gas Utilities Act* (see para. 27) such that "the Board's jurisdiction to consider prior period financial activity of a utility is limited to a 12-month period, even when the financial activity occurs in a deferral account approved by the Board": p. 7. The Board disagreed, partly because of its interpretation of its broad statutory mandate to fix just and reasonable rates. The Board reasoned that DGAs would serve no purpose under Calgary's interpretation because section 40 specifically authorizes the Board to take into account excess revenues or losses in "the whole of the fiscal year" of the rate application (ss. 40(a)(i)) and in any consecutive two-year period thereto (ss. 40(a)(iii)).

26 The Board reiterated its Limitations Decision's conclusion on jurisdiction, found above at para. 21.

Legislation

27 When ATCO applied for this DGA adjustment in 2004, the relevant legislation provided (with emphasis):

Alberta Energy and Utilities Board Act, R.S.A. 2000. c. A-17

Powers of the Board

15(1) For the purposes of carrying out its functions, the Board has all the powers, rights and privileges of the ... PUB that are granted or provided for by any enactment or by law.

. . . . .

(3) Without restricting subsection (1), the Board may do all or any of the following:

(a) make any order that the ... PUB may make under any enactment;

. . . . .

(d) with respect to an order made by the Board ... in respect of matters referred to in clauses (a) to (c), make any further order and impose any additional conditions that the Board considers necessary in the public interest;

(e) make an order granting the whole or part only of the relief applied for;

. . . . .

26(1) Subject to subsection (2), an appeal lies from the Board to the Court of Appeal on a question of jurisdiction or on a question of law.

Gas Utilities Act, R.S.A. 2000, c. G-5

The word "Board" is defined as the Public Utilities Board in section 1(b).

Powers of Board

36 The Board ... may ...

(a) <u>fix just and reasonable ... rates</u>, ...

. . . . .

(e) <u>require an owner of a gas utility to supply and deliver gas</u> to the persons, for the purposes, <u>at the rates</u>, prices and charges and on the terms and conditions that <u>the Board directs</u>....

Rate base

37(1) In fixing just and reasonable rates ... the Board shall determine a rate base for the property of the owner of the gas utility used or required to be used to provide service to the public within Alberta and on determining a rate base it shall fix a fair return on the rate base. ...

Schedule of rates

38(1) For the purpose of fixing the just and reasonable rates that may be charged to consumers of gas by an owner of a gas utility who purchases gas pursuant to a contract under which provision is made

(a) for the progressive increase in the price of gas to the owner of the gas utility,

(b) for an increase in the price of gas to the owner of the gas utility by reason of changes in any prices received by the owner on resale of the gas,

(c) for an increase in the price of gas to the owner of the gas utility by reason of the payment of higher prices by any purchaser of gas in any gas producing area, or

(d) for the redetermination of the price of gas to the owner of the gas utility either by agreement of the parties or pursuant to arbitration,

the Board ... may receive for filing a new schedule of rates that are alleged by the owner to be occasioned by the rise in the price required to be paid by the owner for purchased gas.

(2) The new schedule may be put into effect by the owner of the gas utility on receiving the approval of the Board to it ....

. . . . .

Excess revenues or losses

40 In fixing just and reasonable rates, tolls or charges ...,

(a) the Board may consider all revenues and costs of the owner that are in the Board's opinion applicable to a period consisting of

(i) the whole of the fiscal year of the owner in which a proceeding is initiated ...,

(ii) a subsequent fiscal year of the owner, or

(iii) 2 or more of the fiscal years of the owner referred to in subclauses (i) and (ii) if they are consecutive, and need not consider the allocation of those revenues and costs to any part of that period,

. . . . .

(c) the Board may give effect to that part of ... any revenue deficiency incurred by the owner after the date on which a proceeding is initiated for the fixing of rates ... that the Board determines has been due to undue delay in the hearing and determining of the matter, and

(d) the Board shall by order approve

(i) the method by which, and

(ii) the period, including any subsequent fiscal period, during which,

any excess revenue received or any revenue deficiency incurred, as determined pursuant to clause (b) or (c), is to be used or dealt with.

Public Utilities Board Act, R.S.A. 2000, c. P-45

Jurisdiction and powers

36(1) The Board has all the necessary jurisdiction and power

(a) to deal with public utilities and the owners of them as provided in this Act; ....

(2) In addition to the jurisdiction and powers mentioned in subsection (1), the Board has all necessary jurisdiction and powers to perform any duties that are assigned to it by statute ....

. . . . .

Fixing of rates

89 The Board ... may ...

(a) <u>fix just and reasonable ... rates</u> ...

Chronology of Legislation

28 Some of the following discussion refers to judicial interpretations of predecessor legislation. An understanding of those decisions requires an appreciation of the interaction between the earlier and current legislation.

29 Subsection 67(a) of the *Public Utilities* Act, R.S.A. 1955, c. 267 provided:

67. The Board ... may ...,

(a) fix just and reasonable individual rates ....

30 Section 67 of the *Public Utilities Act* was amended in April 1959 by S.A. 1959, c. 73, s. 9 as follows:

(a) by renumbering the present section as subsection (1), ... [in other words, s. 67(a) became s. 67(1)]

(d) by adding immediately after the renumbered subsection (1) the following subsections:

. . . . .

(2) In fixing just and reasonable rates, ... the Board shall determine a rate base for the property of the proprietor ... and fix a fair return thereon.

. . . . .

(8) ... in fixing just and reasonable rates, the Board may give effect to such part of any excess revenues received or losses incurred by a proprietor after an application has been made to the Board for the fixing of rates as the Board may determine has been due to undue delay in the hearing and determining of the application.

31 In 1960, the *Gas Utilities Act*, S.A. 1960, c. 37 was enacted and provided:

Powers of the Board

27. The Board ... may ...

(a) fix just and reasonable individual rates ...

Rate base

> 28.(1) In fixing just and reasonable rates ... the Board shall determine a rate base for the property of the owner that is used or required to be used in his services to the public within Alberta and fix a fair return thereon.

Excess revenue or losses

> 31. ... in fixing just and reasonable rates, the Board may give effect to such part of any excess revenues received or losses incurred by an owner of a gas utility after an application has been made to the Board for the fixing of rates as the Board may determine has been due to undue delay in the hearing and determining of an application.

32 To summarize, the predecessor of present section 36 of the *Gas Utilities Act* (the power to set just and reasonable rates) is section 27 of the S.A. 1960 version of the *Gas Utilities Act*. The latter's predecessor is subsection 67(a) of the *Public Utilities Act* (later subsection 67(1)). The present section 37 of the *Gas Utilities Act* (fixing just and reasonable rates by determining rate base and fixing a fair return thereon) was section 28 in the S.A. 1960 version and it, in turn, was based on section 67(2) of the 1959 amendments to the *Public Utilities Act*. The predecessor to the present section 40 of the *Gas Utilities Act* is section 31 of S.A. 1960, which took its wording from ss. 67(8) of the 1959 amendments to the *Public Utilities Act*.

Discussion

33 Calgary sees the central issue as the extent to which the Board can engage in retroactive ratemaking. ATCO says the appeal concerns an exercise of discretion by the Board. In my view, the appeal raises the following issues:

> (1) What is the source of the Board's jurisdiction over DGAs?
>
> (2) Did the Board retroactively change rates or did its decision have a prohibited effect?
>
> (3) What standard applies to this Court's review of the Board's decisions?
>
> (4) Against that standard, do the Board's decisions to allow ATCO to use the DGA to record transportation imbalances for 1999 to February 2004 warrant this Court's intervention?

The first two are threshold issues; if the decision under appeal falls because of the answer to either of them, the subsequent issues do not arise.

Issue 1. What Is the Source of the Board's Jurisdiction Over DGAs?

34 Calgary acknowledges "the Board has jurisdiction to set up a DGA or what classes of costs or recoveries are to be included or how they are to be allocated.": Factum at para. 43. This Court implicitly approved the use of deferral accounts in regulated utility rate setting: *ATCO Electric Ltd. v. Alberta (Energy & Utilities Board)*, 2004 ABCA 215 (Alta. C.A.) at para. 26, (2004), 361 A.R. 1 (Alta. C.A.) ("*ATCO Electric*").

35 That said, it is critical to identify the source of the Board's jurisdiction over deferral accounts. If it is section 40 of the *Gas Utilities Act*, time limits apply. If, as ATCO argues, it is sections 36 and 37, that legal impediment disappears.

A. Nature and Function of Deferral Accounts in Utility Regulation

36 A consideration of the nature and function of deferral accounts provides context: Deferral accounts allow a utility to accumulate variances between a utility's approved rate based on forecasted costs and the utility's actual costs for a given period. Typically, at the end of the period, a utility will then collect from customers through a rate rider any balances in the deferral accounts owing by them and refund any balances owing to them.

ATCO Electric at para. 26.

In Alberta, utilities are usually regulated using a future test year regulatory framework in which the Board approves a forecast of a utility's revenue requirements that equates to a forecast of its future costs. However, if the Board is unable to determine a just and reasonable forecast, deferral accounts may be established to deal with uncertain items. In this case, due to the inability to accurately forecast pool prices, deferral accounts were created for 1999 and 2000

. . . . .

Epcor Generation Inc. v. Alberta (Energy & Utilities Board), 2003 ABCA 374) at para. 2, 346 A.R. 281 (Alta. C.A.) ("*Epcor*").

[D]eferral accounts ... are accepted regulatory tools, available as a part of ... rate-setting powers ... [they] ...'enabl[e] a regulator to defer consideration of a particular item of expense or revenue that is incapable of being forecast with certainty for the test year' [citation omitted]. They have traditionally protected against future eventualities, particularly the difference between forecasted and actual costs and revenues, allowing a regulator to shift costs and expenses from one regulatory period to another.

Bell Canada v. Canadian Radio-Television & Telecommunications Commission, 2009 SCC 40, [2009] 2 S.C.R. 764 (S.C.C.) at para. 54 ("*Bell Aliant*").

37 To summarize to this point, descriptions of the general purpose of deferral accounts and the history of this DGA shows that DGAs in gas utility regulation exist to ensure that consumers pay the cost of the gas they consume, with no resulting profit or loss to the utility's shareholders. This general objective has been fully supported by the courts: *ATCO Electric, Epcor, Bell Aliant*, *City of Edmonton, infra.*

B. Source of the Board's Authority

38 What, then, is the source of the Board's jurisdiction to permit the use of DGAs as a regulatory tool? As outlined above at para. 3, the DGA at issue was approved in 1988. Nevertheless, before 1988 the Board employed tools with a similar function to regulate gas utilities. Judicial views about the source of the Board's authority to use those tools are instructive.

39 In the late 1950s the Board proposed a "purchased gas adjustment clause". It would permit the utility to recoup from consumers in the future amounts the utility had to pay for gas that proved more expensive than the utility's estimates, and to refund amounts to consumers if the estimates proved to be greater than the actual cost: *Edmonton (City) v. Northwestern Utilities Ltd.*, [1961] S.C.R. 392 at 396-397, 28 D.L.R. (2d) 125 (S.C.C.) ("*City of Edmonton*"). The Board's jurisdiction to approve such a device was upheld by the Supreme Court, which said that its purpose was to:

> ensure that the utility should from year to year be enabled to realize, as nearly as may be, the fair return mentioned in [s. 67(2)] and to comply with the Board's duty ... to permit this to be done. <u>How this should be accomplished...was an administrative matter for the Board to determine ... under the powers ... to fix just and reasonable rates which would yield the fair return mentioned in s. 67(2)</u>.
>
> *Id* at 406-407 with emphasis added.

The counterparts to the section referred to in this passage are the present sections 36(a) and 37 of the *Gas Utilities Act*.

40 In *Bell Aliant*, the telecommunication regulator, the Canadian Radio Television and Telecommunications Commission's ("CRTC") source of authority to establish deferral accounts was held to be the combined effect of sections 27 and 37(1) of the *Telecommunications Act*, S.C. 1993, c. 38: para. 37. Section 27(1) concerns setting just and reasonable rates, while section 37(1) permits the CRTC to require carriers to adopt any method of identifying the costs of providing services and to adopt any accounting method. The Court added that the "guiding rule of rate-setting under

the *Telecommunications Act* is that the rates be 'just and reasonable', a longstanding regulatory principle.": para. 30. The authority to establish the accounts "necessarily includes the disposition of the funds they contain.": *Ibid*.

41 These cases suggest that the Board's authority over DGAs flows from its power to set just and reasonable rates and a fair rate of return on rate base found in sections 36 and 37 of the *Gas Utilities Act*. Underlying that mandate is the "regulatory compact":

> Under the regulatory compact, the regulated utilities are given exclusive rights to sell their services within a specific area at rates that will provide companies the opportunity to earn a fair return for their investors. In return for this right of exclusivity, utilities assume a duty to adequately and reliably serve all customers in their determined territories, and are required to have their rates and certain operations regulated.
>
> *ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board)*, 2006 SCC 4, [2006] 1 S.C.R. 140("*Stores Block*") at para. 63.

42 I agree with ATCO that the Board's authority over DGAs does *not* come from section 40. Although that provision uses broad language, its function is limited. It permits, among other things, consideration of utility's revenues and costs for the whole fiscal year in which an application for rates is made. It also authorizes adjustments for regulatory lag, that is, the difference between rates the utility seeks when its general rate application is made, and those appropriate when the rates are approved. But it does not limit the Board's general authority to employ other tools (such as the gas purchase adjustment clause and DGAs) that assist in the discharge of its obligation to set just and reasonable rates.

43 It is worth repeating that this principle flows from *City of Edmonton*, where the Supreme Court considered the newly enacted section 67(8) of the *Public Utilities Act* (section 40's predecessor) in conjunction with the recovery of 1959 transitional losses which arose as a result of the 15-month delay between the utility's rate application (June 1958) and the rate approval (September 1959). As to the second issue before the Court, the Board's jurisdiction to permit the establishment of the gas purchase adjustment clause (the DGA's predecessor), the Court referred to "s. 67(2) of the 1959 amendment" (which the Court of Appeal found did *not* grant the Board the necessary jurisdiction to permit the gas purchase adjustment clause) and held at 407 (emphasis added):

> With great respect, however, <u>the proposed order</u> [establishing the gas purchase adjustment clause] <u>would be made in an attempt to ensure that the utility should from year to year be enabled to realize, as nearly as may be, the fair return mentioned in that subsection and to comply with the Board's duty to permit this to be done</u>. How this should be accomplished, when the prospective outlay for gas purchases was impossible to determine in advance with reasonable certainty, was an administrative matter for the Board to determine, in my opinion. This, it would appear, it proposed to do in a practical manner which would, in its judgment, be fair alike to the utility and the consumer.
>
> ... the Board ... propose[s] to make the order under the powers given to it and the duty imposed upon it by the sections to which I have referred to fix just and reasonable rates which would yield the fair return mentioned in s. 67(2).

44 Calgary argues against reliance on sections 36 and 37 as the source of the Board's authority because of the Supreme Court's admonition against employing general statutory authority to ground the exercise of overly-broad Board powers, see e.g., *Stores Block* at para. 50. Elsewhere in the same decision, however, the Court emphasized the need to determine whether the exercise of the proposed power is a "practical necessity for the regulatory body to accomplish the object prescribed by legislation": para. 77. According to the majority, such necessity was lacking in *Stores Block*. Here, for reasons outlined above at paras. 36-37, the use of DGAs is required if the Board is to regulate utilities effectively. Moreover, in *Bell Aliant*, Abella J. explained at paras. 51 - 53 that *Stores Block* did not "preclude the pursuit of public interest objectives through rate-setting". She contrasted *Stores Block* by pointing out that in *Bell Aliant*, the CRTC's rate-setting authority and its ability to establish deferral accounts for that purpose were at the very core of its competence. The same holds true in this case.

Issue 2. Did the Board retroactively change rates or did its decision have a prohibited effect?

45 Calgary argues that by permitting ATCO to use the DGA to make adjustments going back several years the Board engaged in prohibited ratemaking because, in the result, ATCO's present consumers must make up for a past shortfall. I do not agree. I have already explained why I think its power to set just and reasonable rates allowed it to authorize the use of DGAs. It follows that its further orders about *how* to use a DGA did not constitute prohibited ratemaking. As discussed at paras. 69-71, however, this does *not* mean that the effect of its decision on future ratepayers is irrelevant in determining whether the Board reasonably exercised its powers over the DGA.

46 A brief overview of some central principles of ratemaking, including the related concepts of retroactive and retrospective ratemaking, is necessary. Generally, ratemaking and rates must be prospective: *Coseka Resources Ltd. v. Saratoga Processing Co.* (1980), 31 A.R. 541 (Alta. C.A.) at para. 29, (1980), 16 Alta. L.R. (2d) 60 (Alta. C.A.). A utility's past financial results can be used to forecast future expenses, but a regulator cannot design future rates to recover past revenue deficiencies: *Northwestern Utilities Ltd., Re* (1978), [1979] 1 S.C.R. 684 (S.C.C.), at 691 and 699 ("*Northwestern Utilities*").

47 Retroactive ratemaking "establish[es] rates to replace or be substituted to those which were charged during that period": *Bell Canada v. Canadian Radio-Television & Telecommunications Commission*), [1989] 1 S.C.R. 1722 (S.C.C.), at 1749 ("*Bell Canada 1989*"). Utility regulators cannot retroactively change rates (*Stores Block* at para. 71) because it creates a lack of certainty for utility consumers. If a regulator could retroactively change rates, consumers would never be assured of the finality of rates they paid for utility services.

48 Retrospective ratemaking, in contrast, imposes on the utility's current consumers shortfalls (or surpluses) incurred by previous generations of consumers. It is generally prohibited because it creates inequities or improper subsidizations as between past and present consumers (who may not be the same). "[T]oday's customers ought not to be held responsible for expenses associated with services provided to yesterday's customers": Yvonne Penning, "*The 1986 Bell Rate Case: Can Economic Policy and Legal Formalism be Reconciled*" (1989), 47(2) U.T. Fac. L. Rev. 607 at 610. This is sometimes referred to as the problem of inter-generational equity (which the Board discusses at p. 12 of the Limitations Decision reproduced at para. 23).

49 Sometimes *retrospective* ratemaking is referred to as *retroactive* ratemaking. This is because rates imposed on a future generation of consumers, while prospective, create obligations in respect of past transactions, and in this sense they are retroactive: *City of Edmonton* at 402.

50 In this case, the proposed accounting adjustments had retrospective effect: past costs would be borne by ATCO's present southern Alberta consumers, not the 1999 - 2004 consumers who received gas utility services when ATCO's gas costs were incurred.

51 In summary, whether termed retrospective or retroactive ratemaking, imposing gas cost shortfalls or surpluses incurred by past consumers on future consumers is generally prohibited. Although this prohibition against retroactive and retrospective ratemaking is relatively clear, how to apply it in practice is less so. A review of key cases illustrates the complexity.

52 A one-time credit order for consumers was upheld despite the fact that it was "retrospective in the sense that its purpose is to remedy the imposition of rates approved in the past and found in the final analysis to be excessive": *Bell Canada 1989* at 1749. Although the Board's review was retrospective in manner, the credit order was approved through an adjustment to interim rates. The Supreme Court stressed that the regulator had consistently stated its intention to review the interim rates: at 1755. Gonthier J. stated at 1752:

> ... one of the differences between interim and final orders must be that interim decisions may be reviewed and modified in a retrospective manner by a final decision. It is inherent in the nature of interim orders that their effect as well as any discrepancy between the interim order and the final order may be reviewed and remedied by the final

> order... the words "further directions" do not have any magical, retrospective content. ... It is the interim nature of the order which makes it subject to further retrospective directions.
>
> [emphasis added]

53 In *Bell Aliant*, the Supreme Court also upheld a CRTC decision to order the disposition of funds that had accumulated in a deferral account. The Court rejected the argument that this constituted retrospective rate-setting because the rates had already been finalized. Abella J. pointed out that it was known at the outset that the CRTC would make subsequent orders about how to use the balance in the deferral accounts. At para. 63 she added (citations omitted and emphasis added):

> In my view, the credits ordered out of the deferral accounts in the case before us are neither retroactive nor retrospective. They do not vary the original rate as approved, which included the deferral accounts, nor do they seek to remedy a deficiency in the rate order through later measures, since these credits or reductions were contemplated as a possible disposition of the deferral account balances from the beginning. These funds can properly be characterized as encumbered revenues, because the rates always remained subject to the deferral accounts mechanism established in the Price Caps Decision. The use of deferral accounts therefore precludes a finding of retroactivity or retrospectivity. Furthermore, using deferral accounts to account for the difference between forecast and actual costs and revenues has traditionally been held not to constitute retroactive rate-setting ...

54 Calgary argues that cases such as *Bell Canada 1989, Coseka* and *Bell Aliant* are distinguishable. The first two involved interim rather than final rates. In *Coseka*, it was pointed out at para. 36 that consumers must be aware that interim rates may be subject to change. As for *Bell Aliant*, all the parties knew in advance that the telecommunications companies would be obliged to use the balance of the deferral accounts in accordance with subsequent regulatory decisions: para. 61.

55 Calgary suggests that gas rates here had long been finalized because the DGA had been reconciled in accordance with the Board's earlier orders that required forecast and actual gas costs to reconciled on a three-month rolling basis (see Decision 2001-75 at p. 64). It adds that when the seasonal or monthly DGA/GCRR process was approved it was not expressed to involve interim rates, therefore by definition the rates must be final: Factum at para 67.

56 In *Epcor* Fruman J.A. opined that whether deferred accounts are interim or final depends on the facts: para. 15. The material before the Court makes such a determination impossible. Language in the 1988 decision quoted above at para. 4 suggests that the use of the DGA involved interim rates, but that language is vague. In the DGA Decision, the Board noted in section 4.2 ATCO's argument that deferral accounts are by nature interim and therefore not retroactive. Unfortunately, the Board did not express its views on this topic.

57 Both *Bell Canada 1989* and *Bell Aliant* (which concerned deferral accounts rather than interim rates) illustrate the same preoccupation: were the affected parties aware that the rates were subject to change? If so, the concerns about predictability and unfairness that underlie the prohibitions against retroactive and retrospective ratemaking become less significant.

58 Were these parties aware that gas rates were potentially subject to change through the use of the DGA? If so, whether the rates are characterized as interim or final, the principles in *Bell Aliant* govern.

59 The history of DGAs demonstrates that affected parties knew they would be used from time to time to alter gas rates based on later, actual gas costs. Indeed, the Board so found as a fact in the Limitations Decision at p. 4. It adopted the reasoning from that decision in the Reconsideration Decision. The Board's fact findings are not appealable: *Alberta Energy and Utilities Board Act*, s. 26(1).

60 Reconciliation of the DGA/GCRR would sometimes benefit consumers and sometimes not. Gas rates sometimes changed because of the lack of predictability (volatility) in gas prices and sometimes from other factors such as measuring

errors. Whatever the cause, the objective was to ensure that the consumer paid the actual cost of the gas. This legitimate object was accepted by all parties. It strengthened the utility regulatory system by ensuring that the utility received a fair rate of return on its rate base.

61 Therefore, whether the rates should be characterized as final or interim, the use of the DGA in this case did not involve prohibited ratemaking.

Issue 3 - What standard applies to this Court's review of the Board's decisions?

62 The conclusion that the Board had jurisdiction to make the orders about the use of the DGA, and did not thereby engage in prohibited ratemaking, suggests that the reasonableness standard of review should be applied.

63 Abella J. employed this standard in *Bell Aliant* because, in her view, the issues went to the heart of the CRTC's specialized expertise, "the methodology for setting rates and the allocation of proceeds derived from those rates, a polycentric exercise with which the CRTC is statutorily charged and which it is uniquely qualified to undertake.": para. 38, see also para. 56. The same point applies here.

64 Reinforcing this conclusion are the reasons given for applying the reasonableness standard in *ATCO Gas South, Re*, 2008 ABCA 200, 433 A.R. 183 (Alta. C.A.) at paras. 15 - 18 (leave to appeal refused (S.C.C.)). See also *ATCO Electric*, where the Court determined in its standard of review analysis that "[w]ith ... the widespread use of deferral accounts, determining the appropriate methodology to be used in calculating prudent costs of financing these deferral accounts engages the Board's specialized expertise.": para. 63. Reasonableness is also the standard applied to a gas regulator's decision to permit a utility to recover material and previously unrecorded costs for the provision of gas services: *Natural Resource Gas Ltd. v. Ontario (Energy Board)*) (2006), 214 O.A.C. 236, 149 A.C.W.S. (3d) 889 (Ont. C.A.).

Issue 4. Has the reasonableness standard been breached ?

65

> Reasonableness is a deferential standard ... A court conducting a review for reasonableness inquires into the qualities that make a decision reasonable, referring both to the process of articulating the reasons and to outcomes. ... [R]easonableness is concerned mostly with the existence of justification, transparency and intelligibility within the decision-making process. But it is also concerned with whether the decision falls within a range of possible, acceptable outcomes which are defensible in respect of the facts and law.

New Brunswick (Board of Management) v. Dunsmuir, 2008 SCC 9, [2008] 1 S.C.R. 190 (S.C.C.)at para. 47.

In my view, this standard has been breached.

66 The Board's sole justification for permitting ATCO to recoup eighty-five percent of the gas costs it sought from present consumers is found in the following passage of the DGA Decision at p. 11:

> ... the Board must remain mindful of the essential nature of the DGA as a deferral account and the allowances in the past of certain prior period adjustments spanning a number of years. Accordingly, the Board is inclined to allow [ATCO] substantial recovery of the applied for prior period adjustments.

Stripped to its essentials, two reasons emerge: the nature of the DGA as a deferral account and the fact that the DGA had been used in the past to make adjustments over several years.

67 Presumably the "nature of the DGA" point refers to the Board's historical assessment of the DGA contained in section 2.3, entitled "Nature of DGA Adjustments & Recovery Period". In that section, the Board examined the purpose of the DGA when approved in 1988: "reconciling actual costs of gas incurred by a utility with forecasts that it used in setting a GCRR, i.e. the rate it used to recover the commodity costs of gas from sales customers." In describing the

change made in 2001 (altering the reconciliation period from a seasonal to a monthly basis), the Board repeated that the purpose of DGA adjustments was "to allow for forecasting inaccuracies, relative to the timing of actual gas acquisition costs incurred". It is manifest that the costs approved in the decisions under appeal did not fall within the original purpose of the DGA, namely, adjusting for gas price volatility.

68 That brought the Board to its second point, that "during the approximate 16 years that the DGA has been in place, it has been used to update adjusted imbalance amounts from shippers, producers and interconnecting pipelines.": *Id* at p. 10. Usually those adjustments were made within a reasonable time, although sometimes the periods exceeded one year. This observation boils down to "we previously permitted adjustments over longer periods, so we will do so here".

69 Set against these two rationales for granting the bulk of ATCO's application are the Board's many other comments:

- DGAs have evolved into a vehicle to fix all possible gas cost errors and pass them on to consumers;
- when first implemented reconciliations of the DGA were not expected to go back further than 12 months. Longer periods were sometimes accepted under special circumstances
- the DGA "was never set up with the intention of permitting all prior period accounting errors, particularly those that would have been subject to ATCO's management and control";
- accounting errors should typically be absorbed by the utility's shareholders;
- the DGA should not be treated as a catch-all for fixing errors, including those with a long history or resulting from human error, when adequate processes have not been in place to capture and correct the problem at an early stage;
- seven years represents a significant lag presenting obvious inter-generational equity issues;
- ATCO had an onus to ensure the System was working properly and was providing correct data;
- it did not appear that ATCO implemented an appropriate and timely review process for System design;
- there was no evidence of actual internal or external audits being performed to ensure the design was valid as the System was being put into service; and
- between 1998 and 2002 there was a lack of oversight by ATCO to test and develop appropriate controls to ensure that the System output generated was as intended.

70 Mirroring these observations were the Board's reasons for concluding that ATCO should bear fifteen percent of the costs claimed:

- it doubted whether it could rely on ATCO's revised imbalance amounts;
- little on the record demonstrated the extent to which the numbers were faulty, perhaps partly because of ATCO's unilateral actions in destroying data;
- there was no demonstration that the System report was adequately tested at the time of inception;
- the System lacked audits;
- ATCO lacked adequate internal controls and supervisory systems;
- there was inadequate proof of corrections and opening balances; and
- there was a lengthy delay in discovering the errors.

71 In summary, the Board's own analysis highlights the accumulation of factors that make unreasonable its decision to allow ATCO to recover eighty-five percent of the transportation imbalances through the DGA. Unlike most previous uses of DGAs, these charges did not result from gas price volatility. Nor did they resemble other past uses of DGAs where errors were attributable to measuring equipment problems and where there had been no suggestion of utility fault. Here the failure to levy appropriate gas charges was entirely due to deficiencies within ATCO's own system, exacerbated by a long delay in discovering the problem. ATCO's destruction of data made data verification impossible. As a result of the delays, at least some who were not consumers when the problems originated would have to absorb the costs of ATCO's carelessness. Even though this was not prohibited ratemaking *per se*, the long delays gave rise to inter-generational equity issues which lie at the heart of the prohibition against retrospective ratemaking.

72 As outlined in para. 9, previous DGA decisions took account of matters such as the amount of the adjustment, the timeliness of the application, the extent to which the utility acted responsibly, foreseeability of the problem, and whether consumers who received the service would bear the cost of the adjustment. When such factors are applied to this case, it is apparent why the Board's decision is not defensible on its facts.

73 As the Board intimated, there are compelling reasons why this sort of loss should be borne by shareholders rather than long-after-the-fact consumers. Shareholders have the ability to control or at least influence ATCO's management practices. Consumers do not. Requiring consumers rather than shareholders to bear most of the loss does not encourage utilities to conduct operations in a careful, time-sensitive way. The Board itself appropriately observed at p. 5 of the DGA Decision that allowing ATCO (full) recovery "could be considered ... a reward for poor management".

74 The Board's Limitations Decision at least partly addresses the above concerns because it generally limits DGA claims to a two-year period, except in special circumstances not within the utility's control. That decision is not subject to appeal and it would be inappropriate to comment on it further here. Nevertheless, it seems unlikely that the present DGA adjustments would have passed muster under the Board's criteria in the Limitations Decision.

Procedural Matters

75 I agree with Côté J.A's suggestion at para. 238 that the efficient disposition of an appeal can be hindered if parties neglect to provide sufficient copies of Extracts of Key Evidence in appeals like this that require only one copy of the Tribunal's record to be filed. In this case, that difficulty was largely alleviated because the key Board decisions were included in the parties' Books of Authorities.

Conclusion

76 The appeal is allowed, the orders under appeal vacated and the matter returned to the Board for consideration in accordance with these reasons.

***Marina Paperny J.A.*:**

I concur.

***Jean Côté J.A.*:**

A. Introduction and Issues

77 This is an appeal from what was the Alberta Energy and Utilities Board, the rate-regulating tribunal for natural gas utilities. (Its name has changed over the years and is not up-to-date in the style of cause, but I will call it "the Commission".) The issue is whether that tribunal could let the utility company recover a lump sum from present consumers because of mistakes in accounting for past gas purchases by the utility company extending back about six years.

78 Here is an overview of this judgment. Part B describes the odd and lax way in which the respondent utility's problem arose, and the Commission's three decisions about how to handle the utility's ensuing request, and agrees that the Commission's treatment is unreasonable. Part C describes how the Supreme Court of Canada and our Court of Appeal have consistently interpreted the governing statutes and barred retroactive rate-making; and the very limited amendments which the Legislature made in response. Part D describes Alberta's rate-making procedure and law, and shows how the decision under appeal is illegal because retroactive. Part E shows how the deferral accounts used here were created for very different purposes and long since reconciled, remaining almost by oversight. Part F describes the recent *Bell* decision and how it does not apply here. Part G similarly distinguishes two other decisions. Part H is about the standard of review. Part I is about the conclusion and remedy, and Part J makes some requests about procedure.

B. Facts

1. ATCO Finds Significant Error

79 An outsider might suppose that it would not be particularly difficult for a gas public utility to keep track of how much gas it bought, sold or transported, particularly when it does not store any significant amount. Similarly, one supposes that the utility would have accounting records reliably keeping track of what it paid for the various amounts of gas which it got. This case suggests that at some times and places it may not be that easy or straightforward.

80 One reason might be that the respondent ATCO divides its operations. A second reason may be that gas supply to consumers in Alberta has become more complex in the last generation. No longer is the owner of a pipe necessarily the owner of the gas flowing through it, and no longer is the owner of a local gas distribution pipe running under a street necessarily the vendor of the gas being bought by the consumers located on that street.

81 The Commission found a bigger third reason. ATCO had set up some inappropriate accounting systems to handle this situation, inconsistently administered them for years, and throughout made inadequate checks of their operation or adequacy. The Commission so finds in its 2005 decision (pp. 4-5, 7-8, 11-12 A.B. pp. F7-8, F10-11, F14-15).

82 For many years, ATCO seems not to have realized the depth of these problems. Helped by some gentle prodding by the Commission in late 2003, ATCO and its outside accountants investigated their accounting problem more deeply. By early 2004, they recognized fairly serious accounting errors that ATCO had made in northern Alberta for all of the years 1998, 1999, 2000, 2001, 2002, 2003, and for early 2004. In the south, the problem started a year later than in the north, but also lasted until early 2004.

83 The amounts were significant. ATCO's recalculations suggested that in southern Alberta its gas costs from 1999 to 2004 had in fact been a total of $11.6 million higher than it had recorded in any of its books or its regular filings with the Commission. In the north, they were almost $2 million lower for 1998 to 2004.

84 In its first (2005) decision on the subject, the Commission (then the Alberta Energy and Utilities Board) explained the errors as follows.

> AG [ATCO Gas] submitted that there were two distinct aspects of imbalances: the management, control and reporting of other gas owners' imbalances that result from the shipment of other owners' gas through the pipeline network (collectively referred to herein as Transportation Processes), and the recognition of the effect that other gas owners' imbalances have on regulated gas supply procurement and the timing of cost recovery from regulated sales customers (DGA/GCRR Processes).
>
> AG submitted that other gas owners' imbalances were made up of transportation imbalances and exchange imbalances. Transportation imbalances are associated with active transportation contracts, which reflect the physical movement of gas through ATCO's pipeline system. AG described Transportation Processes as including, without limitation, measurement, nomination, allocation, reporting, preparing statements, invoicing and receiving

payment from other gas owners who contract for transportation service. AG also noted that exchange imbalances are those associated with active exchange contracts, which reflect a physical swap of gas between ATCO and a counterparty and in which there are no monthly imbalance settlement provisions. (§ 2.1, p. 3, A.B. p. F6)

The Board [now the Commission] agrees with AG that this Application concerns the disconnection that occurred between the true and correct imbalances reported in the Transportation Processes. . . .

(*id.* at p. 4, A.B. p. F7)

. . . In addition, the Board notes that ATCO did not appear to take the appropriate action to modify the functionality of the TIS system with respect to Rate 11 delivery input which ultimately led AP [ATCO Pipelines] employees to input inaccurate delivery data in order to 'quiet' an error message.

(*id.* at p. 5, A.B. p. F8)

2. ATCO Proposed to Pass on the Shortfall

85 As a result of its belated discoveries, ATCO filed with the Commission's predecessor Application #1347852 of May 31, 2004. ATCO proposed a simple solution: to make ATCO's problem the consumers' problem. The rates for gas delivered from 1998 to 2003 had long since been fixed, charged, and paid, and the gas in question long since sold, delivered, billed, and paid for. Yet ATCO now wanted to turn its old long-undiscovered $11.6 million southern shortfall into a new additional lump-sum charge to present southern customers. Conversely, ATCO volunteered to give a rebate of almost $2 million to present northern customers.

3. The Commission's Three Decisions

86 The Commission responded to ATCO's "error-correction" application in three decisions.

(a) "Imbalance Adjustments" April 2005 Decision # 2005-036

87 In this decision, the Commission made fact-findings about the causes of the errors, which findings are not challenged on appeal by Calgary or ATCO. They reveal ATCO's multifold and long-lasting accounting inadequacies (pp. 7-8, 12 A.B. pp. F10-11, F15). The Commission found as follows:

. . . The Board [now the Commission] considers that the error in the design of the TIS Report along with the management practices related to process control, including those related to the TIS Report, are of concern.

. . . The Board, however, notes a lack of documented audit evidence that would support the correctness of the imbalances reporting systems in the present case, and is thus concerned with the degree of accuracy that AG [ATCO Gas] contends exists for the present imbalances adjustments. Moreover, the Board is concerned with the amount of time, dating back to 1998, that it took ATCO to find, and ultimately make, the imbalances corrections.

(2005 decision, p. 4, A.B. p. F7)

The Board is troubled by what it considers to be **an apparent lack of diligence exhibited by either of AG or AP or both** of them over the reporting of imbalances in as much as the errors included in the review had occurred since at least 1998.

(*id.* at p. 5, A.B. pp. F8, Emphasis added)

. . . The Board notes that AG stated in the Application that "ATCO found that the original design specification for the monthly TIS Report was not correct." This acknowledgment would indicate that before the imbalances problem was identified there had been a **lack of system control over, and audit of, the design**.

> . . . It appears to the Board that if AP employees had not entered the inaccurate Rate 11 delivery data, the incorrect TIS Report may not have been noticed by AG in the normal course of business, given that **it does not appear that ATCO tested or planned to test the integrity of the report** . . .
>
> (*id.* at p. 5, A.B. p. F8, Emphasis added)

88 Yet the Commission did little about the utility's various longstanding accounting inadequacies. It merely deducted 15% as a penalty for them. Subject to that deduction, the Commission did as ATCO asked; it ordered the current southern customers to top up ATCO's profits by an amount equal to ATCO's past bookkeeping errors for those five or more past years.

89 The Commission also allowed ATCO to give the current northern customers a rebate. The Commission did not mention the suggestion that the northern refund bear interest for all the years the utility company had had the funds (January 21, 2005 argument, Commission Record Tab 47, p. 29). Instead, the Commission did the reverse: it dictated that that consumer rebate would be *reduced* by 15% (p. 12, A.B. p. F15). There was no explanation for the reduction, and I cannot think of any logical one. It might have been the Commission's desire for aesthetic facial symmetry between north and south. It seems most unlikely that the Commission intended to penalize the northern consumers for ATCO's shortcomings. Maybe it was just an oversight. After various adjustments, on August 23, 2005 the Commission fixed the northern refund at $541,000, and the leave to appeal does not cover the northern errors or rebate. No one in the north has appealed.

90 The Commission noted that since 1987, ATCO has maintained a deferral account. It was originally set up to allow quick reconciliation of unpredictable fluctuating future gas purchase cost estimates, with actual costs for the same period. The Commission said the purpose for the account has nothing to do with the type of errors in question here, and that the accounts were never designed for purposes such as the current errors. See Part E below for details and citations.

91 Though all the reconciliations of that deferral account had been completed years before, the Commission decided that the new error charge (and rebate) described above would be done through or because of that deferred account.

92 Apart from background and recitals, the actual reasoning of the Commission in this 2005 decision was brief, and contained little or no explanation beyond that summarized here.

93 In particular, these 2005 reasons said nothing about the rule against retroactivity, nor whether the governing legislation permits this sort of retroactive adjustment (going back some six or so years). However, the Commission did seem to suggest that such steps are retroactive rate adjustment for past years' errors: (2005 decision, § 2.8, first para., p. 14, A.B. p. F17).

94 It is probably idle to speculate on the reasons for that significant omission.

95 The Commission's later 2008 Decision says that no one raised the rule against retroactivity during this first (2004) application (2008 Decision §4.3, p. 7, A.B. p. F31). The Commission may have got that idea from allegations in ATCO's October 5, 2007 argument (Commission Record on present appeal, Tab 60, pp. 2, 5, 6). ATCO also alleged the same thing to this Court in 2007: see ATCO's February 22, 2007 factum filed for that previous appeal (pp. 1, 4, 7, 8, 9, 11; cf. p. 10). And cf. similar allegations in the Commission's February 21, 2007 factum (pp. 5, 6). The Commission evidently did not recall its own file (though its 2004-2005 record was consolidated with its 2007-2008 record).

96 In fact, the various statements by ATCO and by the Commission alleging Calgary's silence are not correct. Calgary *did* argue the retroactivity issue during the first hearing, especially in its reply written argument of January 28, 2005 (Tab 50 of the Commission's Record). See especially pp. 2-3, quoting s. 40 of the *Gas Utilities Act*, the key legislation. The date, application number, and title of that written argument all confirm that it was filed for this first application which led to

this first Commission decision in April 2005. The Commission's 2008 decision says that all argument to the Commission on this first 2004-2005 application had been written, not oral (pp. 2-3, A.B. pp. F5-F6).

97 ATCO's inaccurate allegations of Calgary's silence are puzzling. Maybe counsel relied on memory alone. Maybe they interpreted Calgary's written 2004-2005 argument in some unreasonable narrow fashion. And ATCO's 2007 factum may have used terms like "jurisdiction" in a narrow way (e.g. excluding non-jurisdictional Calgary arguments). (See Part D.9. below.) In any event, this is an appeal from the Commission's rehearing, and the "alleged silence" point no longer influences the result (if it ever did).

98 The City of Calgary sought leave (May 30, 2005) and got leave (July 6, 2006: see 2006 ABCA 180 (Alta. C.A. [In Chambers])) to appeal from this 2005 Commission decision. The Court of Appeal allowed the appeal. It said the question could not be decided on the record before the court, doubtless relying on ATCO's erroneous factum. The Court sent the matter back to the Commission to rehear and to reconsider: see 2007 ABCA 133, 404 A.R. 317 (Alta. C.A.).

99 On August 23, 2005, the Commission gave decision 2005-093 approving ATCO's computation of the precise amounts ATCO would collect and refund under the April 2005 decision.

(b) "Limitation Period" May 2006 Decision #2006-042

100 Meanwhile, the Commission itself was properly troubled by the implications of its 2005 precedent. If carried to its logical extreme, it could leave gas rates charged to consumers and payments by past customers forever open to alteration, approaching the lengthy uncertainties in Lord Eldon's Court of Chancery. The Commission therefore ordered a second application about whether the Commission should impose its own limitation period, maybe two years. (It proceeded under a further application which the Commission ordered ATCO to make.) Little was said about the existing limitation period (beginning of the fiscal year of application) found in the *Gas Utilities Act*, and described in Part C below.

101 The Commission's decision on this limitation-period hearing was that the utilities statutes did not matter or apply, because of the old deferral account. So the Commission thought that the extent of retroactivity was more or less a matter of its own discretion. The Commission ordered that henceforth (not retroactively) there would sometimes be a new two-year limitation period for retroactive rate changes. I say "sometimes", because the two-year time limit would not apply where the adjustment sought was large and there were "special circumstances" not within the utility's control.

102 It is not clear whether the "special circumstances" phrase referred to what caused the initial problem, or why the application was made after the expiry of two years.

103 I note that ATCO's limitation-period application was filed after Calgary moved for leave to appeal from the Commission's first decision. And the Commission's reasons on that in May 2006 were almost a year after such leave was sought. The Commission likely knew of those events. But we have to look at the 2006 reasons because they are incorporated into the 2008 decision.

104 ATCO filed a motion in the Court of Appeal for leave to appeal this 2006 decision, but by agreement that motion was adjourned from time to time over the years, and was never heard (see 2008 Commission decision, p. 1). That motion was discontinued recently (February 12, 2010). ATCO later argued before the Commission that Calgary's not trying to appeal this 2006 decision somehow estopped it from questioning the 2005 Commission decision which it has twice appealed (October 5, 2007 argument, p. 6, para. 12, Commission Record Tab 60). I cannot see the logic of that, nor do I recall any law to support it (and none was cited). In any event, no such argument was put to the Court of Appeal on this appeal.

(c) "Reconsideration" January 2008 Decision #2008-001

105 This third Commission decision is the fruit of the rehearing directed by the Court of Appeal, as mentioned above (end of subpart (a)), and the consequent reconsideration application.

106 The Commission refused to let Calgary file any more evidence, despite the Court of Appeal's 2007 direction. (That point is discussed further in Part E.4 below.)

107 The Commission reached the same conclusion as it had in 2005. The key issue was retroactivity.

108 Almost the only significant thing which the Commission said in 2008 about retroactivity was to quote what it had said on the subject in its 2006 limitations decision (subpart (b) above). That is two short paragraphs which read as follows:

> With regard to the issue of retroactive rate-making raised by Calgary, the Board [now the Commission] does not accept the position advanced by Calgary. The Board has broad discretion to set just and reasonable rates and, in the case of setting gas cost recovery and flow-through rates, sets these rates in accordance with the use of DGAs. In doing so, the deferral nature of the DGAs is specifically contemplated and acknowledged when the rates are set. Deferral accounts, by their nature, anticipate adjustments such as the ones at issue in this matter and, as such, cannot be said to constitute retroactive rate-making. The Supreme Court of Canada has approved the use of deferral accounts for gas and has further noted that such a mechanism is a purely administrative matter. In *Epcor Generation Inc. v. AEUB*, 2003 ABCA 374, the Alberta Court of Appeal adopted the same approach and stated that as the deferral account in issue in that decision was not closed, it was not a final order, and was not retroactive rate making or procedurally unfair.
>
> Consequently, the Board considers that a DGA has not been subject to any limitation regarding jurisdiction either by way of legislation, past Board decision or court ruling which would have prevented the Board from considering prior period adjustments to a DGA. In fact, the Board has dealt with prior period adjustments to DGAs since their inception in 1987, with the prior periods being of varying lengths.
>
> (p. 4 of 2006 decision, § 3.1 near end, and quoted on pp. 7-8 of 2008 decision, A.B. pp. F31-32)

A Commission footnote says that the Supreme Court of Canada approval referred to in the quotation is in *Edmonton (City) v. Northwestern Utilities Ltd.*, [1961] S.C.R. 392 (S.C.C.).

109 I am not certain, but the Commission's next 2008 paragraph seems to be about retroactivity as well. So I quote it:

> The provisions of the GUA and PUBA relied on by Calgary authorize the Board [now the Commission] to take into account financial information for the whole of the year in which a tariff application is filed in the event that the Board intends to approve a tariff effective prior to the date on which the tariff application is made. The "prior period" is limited to some period in the calendar year before the date of the application, depending on when the application might be filed in the calendar year. Strictly speaking, deferral accounts are unnecessary to account for financial activity in this period, so the Board does not find Calgary's argument persuasive on this basis.
>
> (p. 8, A.B. p. F32)

One curious feature of that paragraph is discussed at the end of Part D.6 below.

110 There is another paragraph in the decision immediately after that one. I am not entirely certain how to interpret it. It contains some assertions and conclusions. But the only actual reason which I can find in it is one. I read it as saying that the Commission has often acted this way, and if it refused to do so now, it would bring into question its previous decisions.

111 To sum up, the basic real reason given by the Commission was the idea that a deferred account bypasses the ordinary rule against retroactivity.

112 Martin J.A. gave leave to appeal this 2008 Decision (order of July 2, 2009). That is the present appeal.

4. Unreasonable Decision

113 Hunt J.A. concludes that the Commission's decision here is unreasonable. I agree with that conclusion, and with the reasons which she gives for finding unreasonableness. Many other things discussed in my reasons would also help to support that conclusion.

C. Legislative History

1. Introduction

114 The question of whether the impugned Commission decision violates the law forbidding retroactivity requires examining a number of aspects of the nature and policy of that law. I can best start with the history of the relevant legislation and the court decisions about it. That is what this Part C does.

115 A half-century's dialogue between courts and the Legislature is outlined in subpart 2. It reveals a very clear picture. The courts found firm legislative limits which the Legislature adjusted only slightly, and otherwise confirmed, basically keeping them to the present day.

2. Chronology

(a) The *Public Utilities Act*, R.S.A. 1955 c. 267, s. 67 gave the Commission (then the Board of the Public Utilities Commissioners) general powers to fix utility rates, but said little express about time limits or retroactivity.

(b) March and August 1959 saw Commission decisions which were then appealed to the Court of Appeal, whose decision is described in (e) below.

(c) April 1959 the Legislature amended (c. 73, s. 9(d)) the *Public Utilities Act*, adding s. 67(8). Undue delay in hearing and deciding an application henceforth lets the Commission give effect to excess revenues or losses, incurred after filing a utility's rate application, when the Commission fixes just and reasonable rates.

(d) Legislature passed new *Gas Utilities Act* as 1960 c. 37. In its s. 31 has identical wording to the *Public Utilities Act* s. 67(8) just discussed (with one trivial exception).

(e) September 22, 1960 Appellate Division decided ***Edmonton (City) v. Northwestern Utilities Ltd.*** (1960), 34 W.W.R. 241 (Alta. C.A.), considering items (b) and (c) above. The Supreme Court of Canada varied this decision on April 25, 1961 on other grounds (allowing a purchased-gas adjustment clause): [1961] S.C.R. 392, 34 W.W.R. 600. The Supreme Court of Canada held that utility rates must be based on an estimate of future expenses (p. 612 W.W.R.). It apparently accepted the proposition that until the 1959 amendment, the Commission had no power at all to make retroactive rates or allowances, not even for regulatory delay.

(f) Adoption of *Gas Utilities Act* R.S.A. 1970, c. 158, s. 31, which merely reenacted 1960 c. 37, s. 31 (item (d) above) with no change.

(g) December 9, 1976: Appellate Division decided ***Northwestern Utilities v. Edmonton*** 2 A.R. 317 (Alta. C.A.). Its decision was not novel, and is similar to ***Calgary (City) v. Madison Nat. Gas Co.*** (1959) 28 W.W.R. 353, 360. The ***N.W.U.L.*** decision reversed a Commission decision, and held that unexpected shortfalls in revenue or unexpected expenses incurred by a utility before the date of the rate application cannot be considered (paras. 6, 25-26, 34). The Supreme Court of Canada affirmed the Appellate Division in late 1978: (1978), [1979] 1 S.C.R. 684, 12 A.R. 449 (S.C.C.). The Supreme Court explained the 1959 amendment: its scope is narrow.

(h) 1977: Legislature amended s. 31 of the *Gas Utilities Act*: see c. 9, s. 5(1), (2). That did not affect pending cases. Old s. 31 became new s. 31(c). The rest of the section was new.

(i) That new s. 31 (of 1977) became R.S.A. 1980, c. G-4, s. 32, with no significant change.

(j) That section became the present R.S.A. 2000, c. G-5, s. 40, with only minor changes in drafting style. The *Public Utilities Act*, R.S.A. 2000, c. P-45, s. 91 contains virtually identical words. Section 40 of the *Gas Utilities Act* now reads as follows:

> 40 In fixing just and reasonable rates, tolls or charges, or schedules of them, to be imposed, observed and followed afterwards by an owner of a gas utility,
>
> (a) the Board may consider all revenues and costs of the owner that are in the Board's opinion **applicable to a period** consisting of
>
> (i) the whole of **the fiscal year of the owner in which a proceeding is initiated for the fixing of rates**, tolls or charges, or schedules of them,
>
> (ii) **a subsequent fiscal** year of the owner, or
>
> (iii) 2 or more of the fiscal years of the owner referred to in subclauses (i) and (ii) if they are consecutive,
>
> and need not consider the allocation of those revenues and costs to any part of that period,
>
> (b) the Board may give effect to that part of any **excess revenue received or any revenue deficiency incurred** by the owner that is in the Board's opinion applicable to the **whole of the fiscal year of the owner** in which a proceeding is initiated for the fixing of rates, tolls or charges, or schedules of them, that the Board determines is just and reasonable,
>
> (c) the Board may give effect to that part of any **excess revenue received or any revenue deficiency incurred** by the owner **after the date on which a proceeding is initiated for the fixing of rates**, tolls or charges, or schedules of them, that the Board determines has been **due to undue delay in the hearing and determining** of the matter, and
>
> (d) the Board shall by order approve
>
> (i) the method by which, and
>
> (ii) the period, including any subsequent fiscal period, during which,
>
> any excess revenue received or any revenue deficiency incurred, as determined pursuant to clause (b) or (c), is to be used or dealt with.
>
> (Emphasis added)

(Presumably the last three lines should be indented more, but I quote them the way that they appear in the Revised Statutes of Alberta. The equivalent lines are indented more in the *Public Utilities Act*.)

3. Conclusion

116 That legislative history shows that current s. 40 of the *Gas Utilities Act* is the Legislature's limited response to the decisions of the Court of Appeal and Supreme Court of Canada described above (in subpart 2). So the principle of the Court decisions has not changed. The only small change was that the time limits were extended slightly. Though *later* years' expenses or excess revenue can be considered (if they are consecutive), shortfalls or excesses in *previous* years' expenses or excess revenue are still off-limits (as always). Only shortfalls or excesses of revenues and costs back to the

beginning of the fiscal year in which the application is filed, can be considered. That was the precise point in issue in the Court of Appeal decision of 1976 (and Supreme Court of Canada affirmation). That is the only legislative amendment to the Court decisions. New para. (d) on methods and periods is vague, but seems to be purely ancillary (on which see the *Stores Block* decision discussed in Part D.5 below).

117 Given this history, this Alberta legislation is incompatible with any Commission power to take into account to base, or adjust, rates on actual shortfalls or excesses of revenues or expenses in a year earlier than the year in which the application by the utility is filed.

118 Precedent is not the only reason for such rules. The Supreme Court of Canada's and this Court's decisions are based on fairness, certainty and logic. That is explained further below in Part D, which describes those court decisions more fully.

D. The Decision Appealed is Retroactive

1. Introduction

119 This Part D approaches the whole topic of retroactivity from several directions. All these subtopics interlock. Retroactivity cannot be properly described without showing the basics of setting utility rates.

2. Final Prospective Rate-Making

120 There are two ways in which one could regulate how much consumers pay for gas from public utilities. The usual and traditional way is to have rates fixed for a period, at least part of which period is in the future. Then one forecasts all the likely expenses (including cost of capital), and sets rates accordingly. There is some risk to the utility company, as it may get fewer revenues or higher expenses than forecast (or both). Conversely, the company also enjoys the chance of making a higher profit, if costs are below forecast, or revenues higher than forecast. That is the traditional way of making utility rates. (See further subpart 6 below.)

121 That is also the practice with respect to Alberta natural gas rates, and the law requires that procedure. The Supreme Court of Canada explains that clearly in *Northwestern Utilities Ltd., Re* (1978), [1979] 1 S.C.R. 684, 12 A.R. 449 (S.C.C.), on pp. 452 ff. (A.R.). I quote from that judgment (using A.R. para. numbers):

> [4] The Board [now the Commission] is by the [Gas Utilities Act] directed to "fix just and reasonable . . . rates, . . . tolls or charges . . ." which shall be imposed by the Company . . . The Board then estimates the total operating expenses incurred in operating the utility for the period in question. The total of these two quantities is the 'total revenue requirement' of the utility during a defined period. A rate or tariff of rates is then struck which in a defined prospective period will produce the total revenue requirement. The whole process is simply one of matching the anticipated revenue to be produced by the newly authorized future rates to future expenses of all kinds. Because such a matching process requires comparisons and estimates, a period in time must be used for analysis of past results and future estimates alike. . . . It is a process based on estimates of future expenses and future revenues. Both according to the evidence fluctuate seasonally and both vary according to many uncontrollable forces such as weather variations, cost of money, wage rate settlements and many other factors. . . .
>
> [5] While the Statute does not precisely so state, **the general pattern of its directing and empowering provisions is phrased in prospective terms. Apart from s. 31 [now s. 40] there is nothing in the *Act* to indicate any power in the Board to establish rates retrospectively in the sense of enabling the utility to recover a loss of any kind which crystallized prior to the date of the application** (*vide: City of Edmonton et al. v. Northwestern Utilities Limited,* [1961] S.C.R. 392, *per* Locke J. at 401, 402).
>
> [6] The rate-fixing process was described before this Court by the Board as follows:

> The PUB approves or fixed utility rates which are estimated to cover expenses plus yield the utility a fair return or profit. This function is generally performed in two phases. . . . The revenue required to pay all reasonable operating expenses plus provide a fair return to the utility on its rate base is also determined in Phase I. The total of the operating expenses plus the return is called the revenue requirement. In Phase II rates are set, which, under normal temperature conditions are expected to produce the estimates of "forecast revenue requirement". These rates will remain in effect until changed as the result of a further application or complaint or the Board's initiative. . . .

> [7] The statutory pattern is founded upon the concept of the establishment of rates *in futuro* for the recovery of the total forecast revenue requirement of the utility as determined by the Board. The establishment of the rates is thus a matching process whereby forecast revenues under the proposed rates will match the total revenue requirement of the utility. It is clear from many provisions of *The Gas Utilities Act* that **the Board must act prospectively and may not award rates which will recover expenses incurred in the past and not recovered under rates established for past periods. There are many provisions in the *Act* which make this clear** . . . Section 32 likewise refers to rates "to be imposed thereafter by a gas utility".

> [22] It is conceded of course that the Act does not prevent the Board from taking into account past experience in order to forecast more accurately future revenues and expenses of a utility. **It is quite a different thing to design a future rate to recover for the utility a 'loss' incurred or a revenue deficiency suffered in a period preceding the date of a current application. A crystallized or capitalized loss is, in any case, to be excluded from inclusion in the rate base and therefore may not be reflected in rates to be established for future periods**.

> (emphasis added)

See also Netz, "Price Regulation: a (Non-Technical Overview)", in *Encyclopedia of Law and Economics* 396 (2000), at 401-03. (A version of that paper is cited in the *Stores Block* decision of the Supreme Court of Canada, *infra*.)

122 The word "losses" above is ambiguous. In such discussions of retroactivity, it does *not* have its ordinary meaning of a business not so much as breaking even and running at a loss. Instead, the "losses" referred to in this particular context mean actually making less money in a period than had been forecast for that period, because expenses proved larger than anticipated, or revenues proved smaller than anticipated. See *N.W.U.L. v. Edmonton* (1979), *supra* (p. 455 A.R. para. 10, p. 693 S.C.R.). So it can readily refer to a company which is operating at a profit and making a significant return on its investment.

123 The above shows that even the small degree of retrospectivity permitted by the 1959 and 1977 *Gas Utilities Act* amendments is more limited than it sounds. Rates come into force in the future, and are intended to reflect estimates of *future* costs revenues and conditions when they are in force. The rule against looking at losses (or extra profits) which occurred before the application date is not arbitrary; in part it reflects that rule of future rate-making. Past ongoing expenses can be looked at when predicting future ones, but past unexpected shortfalls (one-time events) in general can never be recovered. I return to the stages of the rate-making process, and some confusion about it in subpart 6 below.

124 That is orthodox and traditional rate-making law: see 1 Priest, *Principles of Pub. Util. Regulation* 75, including n. 102 (1969); Netz, *loc. cit. supra*. And see subpart 4 below. The legislation confirms that law. What was referred to in the earlier court decisions as s. 31 or s. 32 of the *Gas Utilities Act* is now s. 40. It requires "rates, tolls or charges . . . *to be* imposed, observed and followed *afterwards* by an owner of a gas utility." (emphasis added)

125 The Supreme Court of Canada's 1979 *N.W.U.L.* decision then quoted with approval another decision of this Court also explaining the 1959 amendment to the legislation:

> . . . It was to deal with rates prospectively and having done so, so far as that particular application is concerned, it ceased to have any further control. To give the Board [now the Commission] retrospective control would require clear language and there is here a complete absence of any intention to so empower the Board.
>
> - ***Calgary (City) v. Madison Nat. Gas Co.*** (1959) 28 W.W.R. 353, 19 D.L.R. (2d) 655, 661 (quoted at end of para. 7 (A.R.) of the Supreme Court of Canada's 1979 ***N.W.U.L.*** decision)

126 The Supreme Court also quoted with approval another decision of this Court on the unfairness of retroactive rate hikes:

> One effect of this ruling is that future consumers will have to pay for their gas a sum of money which equals that which consumers prior to August 31, 1959 ought to have paid but did not pay for gas they had used. In short, the undercharge to one group of consumers for gas used in the past is to become an overcharge to another group on gas it uses in the future. When the Board capitalized this sum, it made all the future consumers debtors to the company for the total amount of the deficiency, payable ratably with interest from their respective future gas consumption.
>
> - ***Re N.W.U.L.*** (1961) 34 W.W.R. 241, 25 D.L.R. (2d) 262, 290 (quoted in para. 21 (A.R.) of Supreme Court of Canada's 1979 ***N.W.U.L.*** decision)

127 That danger is acute here, with 2005 customers asked to pay what 1999 customers consumed but allegedly did not pay. And Calgary has a very mobile population and grew rapidly through the early 2000s.

3. Cost-Plus Billing

128 If one were to ignore all the law above, in theory gas utilities could instead use a different system. Consumers could pay them for gas on a cost-plus basis. Cost-plus is the way that government contractors like to be paid, and that law firms often charge. In theory, one could simply set rates for each year after the fact, once all the gas had been consumed, and all the consumption and expense figures were in and verified. In the meantime, consumers would merely pay something on account, and have the actual final figure adjusted later by a refund or extra charge.

129 Such a full cost-plus system would be novel in public utilities. And probably unworkable if done openly. But, in my view, ATCO's request which the Commission approved here is perilously close to that in all but name. That is not just my speculation. The Commission more or less said so itself, in its 2005 decision (p. 10, A.B. p. F13), and its 2006 decision (p. 2), both quoted in Part E.2 below.

130 The cost-plus system has dangers. Of course one is the intergenerational expropriation referred to by this Court, and by the Supreme Court of Canada (in its *N.W.U.L.* 1979 para. 21 quoted at the end of subpart 2 above).

131 When I discuss incentives at various places in this judgment, I am not imputing improper motives. A utility company is not a charity, and its directors and officers have a duty to its shareholders to maximize its profits (to the extent that the regulatory bodies and law and honesty permit).

132 Here is another danger. If the utility ends by making a profit, and there is no automatic adjustment at year end, the utility can hope that no consumer group will make a fuss, and so the company can hang on to the profit. If consumers do apply to the Commission, the utility can suggest that it is too early to tell, and to wait a few years to see if arguable offsetting losses turn up elsewhere. So what revenues to offset against what expenses becomes almost arbitrary. Conversely, if the utility makes a loss at year end, it can apply immediately for an additional payment by consumers. The utility will have recourse to the regulator only when the facts mean that it will win and the consumers will lose. On the evils of changing the rules in mid-game, see MacAvoy and Sidak (2001) 22 Enr. L. Jo. 233, 238. Recall that the Alberta deferred rate account is just a number written in a book. It is not a trust account in a bank, or any other type of segregation of funds; nor is it even funds.

133 And of course cost-plus billing contains no incentive to be economical. Cf. Netz, *loc. cit. supra*, at 403 ff.

134 Therefore, routing later claims immediately through an old deferred account to give refunds or extract higher rates, in respect of profits or losses years before, in substance is no fixed rate at all (and so clearly illegal). At best it is simply basing rates to be paid in the future on failure to forecast expenses in past fiscal years. As noted above in Part C.2 and in Part D.2, the legislation forbids that. Section 40 of the current *Gas Utilities Act* (quoted in Part C.2) only lets that process look back to the beginning of the fiscal year in which the rate application was filed. I see no exception there for different accounting methods.

4. Commission Powers are Confined by Legislative Aims

135 In Parts C and D.2 above, I showed that the Supreme Court of Canada and this Court consistently barred retroactive rate-making in general, and banned increasing present rates to cover a past unexpected shortfall in particular, and showed how the Legislature affirmed that (with only small changes).

136 The justice, consistency, and policy underlying those legal rules have since been explained by the Supreme Court of Canada. It also shows how to interpret such legislation. Its latest decision on the Alberta régime in general, and gas utilities in particular, is the "*Stores Block*" decision, cited as *ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board)*, 2006 SCC 4, [2006] 1 S.C.R. 140, 344 N.R. 293, 380 A.R. 1 (S.C.C.). It clearly sets out the Commission's proper approach.

137 The Supreme Court there says that how much discretion utilities or other regulatory tribunals have varies from board to board, but each board must respect the limits of its jurisdiction, and can only act in areas where the Legislature has given it authority (paras. 2 and 35). Utilities regulators regulate rates to protect consumers from natural monopolies (para. 3).

138 The Supreme Court of Canada says that though Alberta's *Alberta Energy and Utilities Board Act* and *Public Utilities Board Act* and *Gas Utilities Act* contain seemingly broad powers, that legislation must be interpreted within the entire context of the statutes, which balance need for consumer protection against owners' private property rights. The main function of the Commission is to fix just and reasonable rates, so ensuring dependable supply (paras. 7, 60). Therefore, imprecise undefined wide statutory provisions letting the Commission make any order, or impose any condition necessary in the public interest, do not give an unfettered discretion. They must be limited to the purpose of the legislation and the context of the regulatory scheme and principles generally applicable to regulatory matters (paras. 46, 48, 49, 50, 51, 60, 61, 64, 73-77). The "power to supervise the finances of these companies and their operations, although wide, is in practice incidental to fixing rates" (para. 60).

139 The Supreme Court then examines the history of the Alberta legislation, which is based on similar American traditional utilities rate-regulation legislation (para. 54). Such "public utilities are very limited in the actions they can take" and the Commission has no "discretion . . . to interfere with ownership rights" (para. 58). The 1995 (temporary) merger of the Public Utilities Commission and the Energy Resources Conservation Board (as the Alberta Energy Utilities Board) did not change that, says the Supreme Court (para. 59).

5. Shareholders' Risk

140 The law's time restrictions are neither mechanical, nor trivial. They are bound up with who enjoys windfall profits, and who risks losses or low returns on investment. The Supreme Court of Canada begins by describing the rate-making process:

> The [Commission] approves or fixes utility rates which are **estimated** to cover expenses plus yield the utility a fair return or profit. . . . The revenue required to pay all reasonable operating expenses plus provide a fair return to the utility on its rate base is also determined . . . In Phase II rates are set, which, under normal temperature conditions are

> **expected** to produce the estimates of '**forecast** revenue requirement'. These rates will remain in effect until changed as the result of a further application or complaint or the Board's initiative. Also in Phase II existing interim rates may be confirmed or reduced and if reduced a refund is ordered.
>
> ("***Stores Block***", 2006 SCC 4, para. 65, quoting the Supreme Court of Canada's 1979 ***N.W.U.L. v. Edm.*** decision, emphasis added)

141 Then the Supreme Court shows that the object is to leave key risks to the equity holders, the utility shareholders:

> Despite the consideration of utility assets in the rate-setting process, **shareholders are the ones solely affected** when the actual profits or losses of such a sale are realized; the **utility absorbs losses and gains**, increases and decreases in the value of assets, based on economic conditions and occasional unexpected technical difficulties, but continues to provide certainty in service both with regard to price and quality. (*id.* at para. 69, emphasis added)

142 Therefore, the Commission cannot act retroactively and offload risk onto consumers:

> . . . the Board [now Commission] was in no position to proceed with an implicit refund by allocating to ratepayers the profits from the asset sale because it considered ratepayers had paid excessive rates for services in the past. . . . **The Board was seeking to rectify what it perceived as a historic over-compensation to the utility by the ratepayers. There is no power granted in the various statutes for the Board to execute such a refund in respect of an erroneous perception of past over-compensation. It is well established throughout the various provinces that utilities boards do not have the authority to retroactively change rates** [citing ***N.W.U.L.***, ***Coseka***, and ***Dow*** cases]. But more importantly, it cannot even be said that there was over-compensation: the rate-setting process is a speculative procedure in which both the ratepayers and the shareholders jointly carry their share of the risk related to the business of the utility.
>
> (*id.* at para. 71, emphasis added)

143 Striking for the present appeal is the Supreme Court's discussion shortly before that quotation. It says that the utility is not guaranteed a profit, nor a return on its assets, and is merely given a chance to earn them. The utility company owns the assets, and profits or losses accrue to the company (i.e. shareholders), not to the consumers.

> The disbursement of some portions of the residual amount of net revenue, by after-the-fact reallocation to rate-paying customers, undermines that investment process . . .
>
> (*id.* at para. 67)

The customers have no ownership or equity; only shareholders do:

> Shareholders have and they assume all risks as the residual claimants to the utility's profit. Customers have only 'the risk of a price change resulting from any (authorized) change in the cost of service. This change is determined only periodically in a tariff review by the regulator'.
>
> (*id.* at para. 68)

144 The long history of that policy and system are confirmed by an article (also quoted by the Supreme Court): MacAvoy and Sidak (2001) 22 Enr. L. Jo. 233, 235, 237, 241-42, 243-44, 245-46.

145 This traditional prospective fixed rate-making provides very healthy incentives for the utility company and its shareholders and management. If the utility company can find ways to hold its expenses below those which were forecast, all the extra profit accrues to the shareholders and cannot later be confiscated. In the long run, that approach will benefit both the shareholders and the consumers. For a useful discussion of incentives, see Kahn, *The Economics of Regulation: Principles and Institutions*, v. 1, pp. 47-54, 101-09 (repr. MIT Press 1998).

146 Besides incentives, that system also gives fairness to the utility company's shareholders. If applied consistently, it is just for everyone.

147 Calgary's initial January 21, 2005 argument to the Commission (Tab 47, p. 3), pointed out that ATCO's 2004 error-correction application was in effect a request for a backstop guarantee against unexpected shortfalls in profit, citing previous Commission decisions. The Commission's 2005 decision does not mention that concern. The quotations from the Supreme Court of Canada above show the fundamental error in the Commission's 2008 decision now under appeal. And it is also virtually cost-plus billing, as noted in subpart D.3 above.

148 Indeed, the Commission's own 2005 decision (being reconsidered here) admits that ATCO's proposal "replaced a prospective process where accounting errors, such as those that are the subject of the Application, should typically have been absorbed by the utility's shareholder" (p. 11, A.B. p. F14).

6. Stages of a Rate Hearing

149 The term "retroactive" is misleading or confusing in some respects. It is conceivable that it led to some of the unexplained aspects of the present situation. Compounding the problem is the fact that several different things are involved. So expanding on what the Supreme Court of Canada said in *Stores Block* will increase clarity.

150 I will outline simply the traditional and proper process to set or amend rates for a public gas utility in Alberta. (Legal authorities are found above, especially in Part C.2 and subparts D.2 and 5.)

> Step A: Utility completes fiscal years #1 and 2, and routinely files or publishes its financial results for those years.
>
> Step B: During fiscal year #3, Utility files an application to the Commission to increase its existing rates to consumers.
>
>> (1) This application always includes (and must include) an **estimate** of what expenses, taxes and rate base will be during the (current) fiscal year #3, and during (upcoming) fiscal year #4.
>>
>> (2) If the Utility wishes, it may choose also to show the Commission that in the past, some of its expenses have been higher than had previously been forecast, or that some of its revenues have been lower than had previously been forecast. However, legislation and case law (see Part C above) allow the Commission to rely upon such discrepancies between past estimates and actual figures (revenue or expenses), only for two possible time periods:
>>
>>> (a) the current fiscal year, during which the application was filed (i.e. fiscal year #3);
>>>
>>> (b) any period during which the current rate hearing is still going on, or the rate decision is standing reserved and not yet decided (i.e. fiscal year #3, and also year #4 up to date of decision).
>
> Step C: In Phase I, the Commission sets its own estimate of the expenses and taxes which the Utility will incur, e.g. in year #4, plus a reasonable rate of return on its investments (rate base) for the foreseeable period after the application date. That is a lump sum of future needed gross revenue per year (or month). Then in Phase II, the Commission estimates future gas consumption, and designs a set of rates which it estimates will produce that lump sum of needed gross revenue.

It will be seen from this outline that all rates are future.

151 Typically, the word "retroactive" is used in this context to refer to something very specific. That is going outside the time limits in step B(2) above. For example, the Commission cannot set a rate which will yield more than the estimated

future expense, taxes, and return on investment. It cannot do so even if it is proven that the utility earned much less in year #1 (or earlier) than had been estimated, or than the old rates were designed to cover. That is a past loss and is unrecoverable. Similarly, the Commission cannot set future rates which will yield less than estimated future expenses etc. on the ground that in the past year #1 (or earlier) the utility earned more than had been forecast.

152 Those forbidden acts would not be "retroactive" (or retrospective) in all the common non-technical senses of the word. The common term "retroactive" is appropriate in two senses only. First, all rates should be for the future and known at the time that the consumer decides to consume some (or more) gas. Rates come into force only on the day they are announced (or a later day). (Interim rates are a partial exception, and ignored above for simplicity.) On any given day, a consumer knows what rates apply.

153 The second meaning of "retroactive" is that already described above: that deviation between past estimates and past actual performance is no ground to change future rates for a later period.

154 Therefore, one must not confuse two different topics:

(1) First topic: whether *future* consumption or expenses will be the same as forecast now;

(2) Second topic: whether *past* expenses were the same as previously forecast some years ago.

The first topic (future uncertainty) is sometimes handled by purchased-gas adjustment clauses or deferred gas accounts for gas (raw material) expenses or allied topics. It is in effect a type of temporary interim rate. But the second topic (past discrepancies from budget) is never legitimately allowed for, so long as it is for a previous fiscal year. *A fortiori*, past accounting errors are even less legitimate a topic for later adjustment of rates (even by later surcharges to consumers or refunds to consumers).

155 In my respectful view, what the Commission did here (at ATCO's request) is therefore forbidden by binding case law and statute in two respects.

156 Written argument to the Commission was not exhaustive, and may not have spelled out every implication of these points. Possibly the Commission did not distinguish the "first topic" from the "second topic". Its actual reasons on this topic were not lengthy, but I note two things. In Part B.3(c), I quoted the middle paragraph of the Commission's 2008 reasons ("The provisions of the GUA and PUBA relied on . . ." p. 8, A.B. p. F32.) In the mention of retroactivity, note the phrase there "in the event that the [Commission] intends to approve a tariff effective prior to the date on which the tariff application is made." But no such condition or qualification exists in s. 40 or the case law. The time limit about past under-recoveries applies just as much to rates to come into effect later (as rates almost always do). Parts C and D show that at length. Little in the Commission's 2006 or 2008 reasons reviews or applies the full force of the law recited here in Parts C and D. And the original purpose of the deferred gas accounts (step B(1) above) morphed in 2005 into a repeal of the restrictions in step B(2) above.

7. Interim Rates

157 For all the reasons above, the only legitimate exception to the bar on retroactivity which I see as even arguable, is interim rates.

158 An interim order must later be replaced by a final order, and the rate will no longer be open to change. See *Coseka Resources Ltd. v. Saratoga Processing Co.* (1980), 31 A.R. 541 (Alta. C.A.), and *Calgary (City) v. Home Oil Co.* (*supra*, Part D.2) at 662-63 (D.L.R.) cited with approval by the Supreme Court of Canada in *Bell Canada v. Canadian Radio-Television & Telecommunications Commission*, [1989] 1 S.C.R. 1722 (S.C.C.), 1752h-1754f; and also see p. 17600g-1761a.

159 ATCO's October 5, 2007 argument (Tab 60, paras. 23-26, p. 9) is about *Edmonton (City) v. Northwestern Utilities Ltd.*, [1961] S.C.R. 392 (S.C.C.). But that argument acknowledges that the rates dealt with there which were subject to the "purchased gas adjustment clause" were interim. Note Calgary's reply argument of October 12, 2007 (Tab 65) pp. 6-8.

160 The term "interim" is ambiguous. But the traditional meaning is just that a full rate hearing would take too long, and the company cannot afford to go on that long under the old rates (especially in inflationary times). So a quick and approximate rate increase is put in, in the expectation these new rates will soon be replaced by more careful ones. That usefully leads to an overlapping topic, the purpose of deferral accounts.

161 In Parts D.8 and E below, I show why the rates in question here were not interim, still less permissibly interim.

8. Function of Deferred Accounts

162 The legitimate use of deferred gas accounts fits best here. I will discuss the history of these particular accounts below in Part E.

163 Is a deferred account any exception to all the law given above? Only to a very limited degree. If the Commission sets an *interim* rate which must be later adjusted and made final, then everything done in the meantime under that interim rate is tentative. That creates two needs. First, the utility company's accounts must be flagged to show that. Second, it may be informative and useful to keep track of and total any discrepancies building up in the meantime, such as the difference between anticipated gas costs and actual gas costs. There are doubtless several methods which would meet those two needs; one method is a temporary deferred account to be adjusted and closed out when the final rate is set.

164 Therefore, a legitimate deferred account is a result, not a cause; a mere tool, not an objective. Such an account does not cause or legitimize rate changes any more than fur hats cause or legitimize winter.

165 It is one thing to create a deferred account at the outset of an *interim* rate, to specify what amounts it is to record during that period, and then at the end to reconcile and clear out the account by the final rate, in the way ordained at the outset.

166 It is quite another thing to return later to a fixed *final* rate and change it after the fact by ordering premium payments by (or refunds to) consumers, and then to try to justify that by *creating* for the purpose a *new* deferred account, into which sums will be put retroactively and immediately be removed (by the premium or refund). And in substance it would be the same to find an old page still in the ledger, which had been created for a different specific purpose but long since closed out and reconciled, and then use it. In other words, retroactively to put into that page (account) the new sum and immediately take it out. That is wrong in principle and in law. It is just changing a final rate after the fact, even after the consumption. See Calgary's argument to the Commission of January 21, 2005, p. 2 (Commission Record, Tab 47).

167 Any deferred account which is mere memorandum (calculation) by itself changes nothing, excuses nothing, and is at best a result, not a cause. But if it is regarded as unallocated funds whose later ownership depends on profits or losses, then it likely violates the Court of Appeal and Supreme Court of Canada rulings in *Stores Block* and similar decisions (in Parts D.2 and D.5 above). The refund here to the consumers of the unexpected profits plainly falls within that. And the reverse, recouping unexpected profit shortfalls in the deferred accounts, is an even bigger violation of that case law. So for those reasons, I do not see a deferred account as any licence to violate the usual legal rules barring retroactive rates or use of expense overruns too far back.

168 What if the utility (with or without the permission of the Commission) were ahead of time to set up an unrestricted all-purpose "deferred account" intended to last indefinitely and to permit any rate to be adjusted later because of old events? In my view, that would be tantamount to a purported repeal of s. 40 and the Supreme Court of Canada decisions. No one but the Legislature has power to do that.

169 ATCO suggested to the Commission that the 1987-1988 deferred gas accounts were not "closed" but "left open" (para. 28, p. 10, ATCO's October 5, 2007 argument, Comm. Record, Tab 60). The words "left open" are ambiguous. The account was still there, but the relevant years had been reconciled (cleared out) years ago. See Part E below, and

the Appendix to this judgment. So in the meaningful sense, ATCO's submission was incorrect. It had some accuracy only in an irrelevant sense.

170 ATCO's same argument (para. 31, p. 11) said that past rates are not changed by the DGA. In a sense, that is of course so. But it says that "future rates reflect, *inter alia*, prior period adjustments occurring . . . in the setting of future rates." That is precisely what the *Gas Utilities Act* and Supreme Court of Canada and Court of Appeal decisions all forbid. See Parts C and D.1-8 above.

171 I stress that using a deferred account is the only real reason which the Commission gave for its 2008 Decision now under appeal.

9. Jurisdiction

172 First, I put to one side a red herring. In its reasons under appeal, the Commission states (without citing authority) that there are no fixed rules about retroactivity, only discretion. The Commission says that such issues "are not, however, jurisdictional impediments" (second last para., p. 8, A.B. p. F32). That seems to echo part of what ATCO had argued (October 12, 2007 argument, p. 4, para. 8, Record Tab 64).

173 The Commission's statement is irrelevant. Errors of law and errors of jurisdiction yield the same result on appeal (if clear and unreasonable). As shown above at great length, retroactivity violates a clear rule of law. This is an appeal, and this Court is not confined to questions of jurisdiction. It has power to reverse decisions of the Commission for errors of law: *Alberta Utilities Commission Act*, 2007, c. A-37.2, s. 29(1).

174 Now I turn to another topic. I should emphasize that the above portions of my reasons do not find want of jurisdiction or power on the part of the Commission. The preceding parts of my judgment are not a search for a power. So it cannot be a power which existed somewhere else. My suggestion is not a power, or jurisdiction. Instead, I find a legal statutory prohibition (statutory and judge-made).

175 That distinction imports two things. The first is that powers are very different from rights, and lack of power (technically called a "disability") is very different from a duty. A prohibition and a lack of power operate in different spheres entirely. A power is the *ability* to affect other people's legal position. A right or duty has to do with what the law *requires* or *forbids*.

176 One can have a power but be under a legal duty not to use it, or not to use it a certain way. See *Dias on Jurisprudence*, 53-54, 56-57, 64 (4th ed. 1976) or pp. 33-34, 36-38, 43-44 (5th ed. 1985); *Salmond on Jurisprudence* 229-30 (12th ed. 1966). An example is an agent making a contract forbidden by the principal, but within the agent's authority. Another is a divorced spouse who cuts the children out of his will contrary to a contract with his ex-wife. (Of course, we must remember that the Commission is a tribunal, not a litigant.)

177 The second thing flowing from rights vs. powers in this case is easy to overlook. I find an applicable statutory (and precedential) prohibition, not mere non-existence of a grant of power. In other words, I rely on the presence of an actual thing, not the absence of something. Silence in one place does not contradict an express statutory provision in another (whether the issue is powers or duties).

178 Probably that is the key point. Existence of even one relevant statutory grant of power *upholds* a positive power; even one statutory provision *prevents* legal action if the statutory provision is a negative prohibition. So if the issue were whether a tribunal or person had *power* to do something, only one source of the power would be necessary, and would suffice. That the power came only from one source or location, would be irrelevant; one source or many would make no difference. If instead the issue is whether there is a statutory *prohibition*, then again it need only be found in one place. Even one such statutory provision means that the tribunal or person has *no* right, and the law forbids it to act. And the provisions on which I rely bar rates based on past losses or optimistic forecasts, not approve it.

179 But there is one difference between the two situations. A statutory grant of power permits effective action; a restriction makes action illegal.

180 An appeal from a tribunal's act will succeed if the tribunal lacked power, *or* if it contravened a statutory or judge-made legal prohibition, *or* both. So a tribunal acting within jurisdiction and with power, must be reversed if it violated a rule of law. The Court of Appeal must quash it.

181 Here the Commission had and has *power* to regulate rates, to enter into a hearing of some sort, to prescribe accounting methods, and to grant a wide variety of remedies. The remedies which the Committee granted here were familiar and within its *powers*. None of that is the issue.

182 The whole issue is what legal rules that hearing was to follow, what considerations or facts were relevant or irrelevant, times for acting, and the limits on reversing earlier decisions. Violation of those legal rules likely produced no nullity. But such violation is illegality, and permits, indeed mandates, appellate reversal.

10. Conclusion

183 This charge to the southern customers to reimburse ATCO for its various accounting deficiencies is illegal retroactive rate-making for ten reasons.

> (a) It is all based on events long before the beginning of the fiscal year of the application, indeed totally outside any rate application. That contravenes all the law set out in Part C (history) and in subparts D.2 to D.6 above. If the adjustment application is even a rate application, it is a May 2004 application, but the adjustments go back to 1998 or 1999.
>
> (b) The rates were final years ago, at the latest when the DGAs were reconciled monthly.
>
> (c) The DGAs themselves were thus reconciled years before.
>
> (d) The DGAs were never intended nor ordered to be used for this purpose. See Part D.8 above, and Part E below.
>
> (e) ATCO's and even the Commission's reasoning would imply that the existence of this one continuous deferred account going back to 1987 or 1988 would leave open all future gas rates back to those years! That would be absurd.
>
> (f) This is just errors from lax accounting, discovered belatedly.
>
> (g) The Commission never even discussed the implications of the fact that on its own fact statements, this is basically cost-plus charges, not fixing rates. The essence of that is at best retroactive rates, at worst no rates at all. See Parts D.2, D.3, and D.5.
>
> (h) The Commission shuffles the risk of shortfalls in profit onto the consumers (or rather different later consumers). See Parts D.3 and D.5.
>
> (i) The Commission's reasons seem to contain errors on their face. See the end of Part D.6.
>
> (j) This is clear and unreasonable error of law. See Part D.9.

E. History of Deferred Gas Accounts

1. Introduction

184 Since the Commission later saw deferred accounts as a way to bypass the retroactivity rule, the nature and history of the accounts in question here is important.

185 These accounts are so old that they were set up 22 years ago for different companies which once had the gas franchises which ATCO now enjoys.

2. Creation and Purpose

186 I quote the Commission's own history of these accounts, to show that they were never intended for the present purposes, and had long since been reconciled (cleared out) for the years in question.

> DGA [deferred gas account] procedures were initially approved by the Board [now Commission] in 1987 and finally approved in 1988 **for the purpose of reconciling actual costs of gas incurred by a utility with forecasts that it used in setting a GCRR [Gas Cost Recovery Rate], i.e. the rate it used to recover the commodity costs of gas from sales customers**. These procedures ensured that customers paid only the actual cost of gas consumed by them. In addition, they ensured that the utility neither profited from nor suffered losses in the course of selling the gas. This premise currently remains in effect for the sale of gas under a regulated rate.
>
> **Initially, reconciliation of the DGA was made on a winter and summer seasonal basis** when the application for the respective period's GCRR was filed. **In 2001, the Board approved a change in the methodology for determination of a GCRR from a seasonal to a monthly basis**. This change in methodology was implemented in April 2002. The purpose of allowing prior period adjustments in the DGA was to allow for forecasting inaccuracies, relative to the timing of actual gas acquisition costs incurred, that would have otherwise impacted the determination of a GCRR.
>
> (2005 decision at p. 8, A.B. p. F11, emphasis added)
>
> The Board concluded from this prior decision that the DGA was not intended to be a permanent fixture, but was expected to be in place until the volatility of gas prices had decreased to a point where AG could revert to its previous practice of forecasting the gas costs on a prospective basis. The difference between the two practices was that prior to the implementation of the DGA, any difference between forecast and actual was to the account of the shareholder, whereas in the DGA process the differences fell to the account of the customer.
>
> It is clear to the Board that the only purpose of the DGA was to provide a method of correcting the customer rates due to the volatility in the purchase price of natural gas.
>
> (2005 decision at p. 10, A.B. p. F13)
>
> . . . the Board must remain mindful of the essential nature of the DGA as a deferral account and the allowances in the past of certain prior period adjustments spanning a number of years.
>
> (2005 decision at p. 11, A.B. p. F14)
>
> Decision E88018, dated March 18, 1988 stated:
>
> **The DGA procedure was proposed [by AG's predecessors] to be in place until gas costs could be forecast with a reasonable degree of certainty**.
>
> and in a later section also stated:
>
> [AG's predecessor] contended that once gas prices attain some stability and can be forecast with some degree of accuracy, there likely will be no need for a DGA type account. If a DGA mechanism is not approved, [the predecessor] suggested that there would be significant swings to its earnings. [The predecessor] confirmed that when the first reconciliation proceedings are held, the Board and the Intervenors may examine not only the projected

gas costs for the next reconciliation period but also those costs that are related to the period under review. (Tr. p. 488) And further:

> There's no attempt in the deferred gas account mechanism that's been proposed to bypass the Board's ability to rule on the prudence of a cost.(Tr. p. 489)

The Board concludes from this prior decision that **the DGA was not intended to be a permanent fixture, but was expected to be in place until the volatility of gas prices had decreased** to a point where AG could revert to its previous practice of forecasting the gas costs on a prospective basis. The difference between the two practices was that prior to the implementation of the DGA, any difference between forecast and actual was to the account of the shareholder, whereas **in the DGA process the differences fell to the account of the customer**.

It is clear to the Board that the only purpose of the DGA was to provide a method of correcting the customer rates due to the volatility in the purchase price of natural gas. (*id.* at pp. 9-10, A.B. F12-13, emphasis added, footnotes omitted)

In some cases, . . . prior period adjustments have been specifically approved for imbalances resulting from measurement errors that have related to periods of over one year.

(2005 decision at pp. 10-11, F13-14)

Previous to the establishment of the DGAs, a utility treated all estimates for its gas supply, both volume and price, as prospective in its General Rate Application (GRA). The establishment of the DGA provided a means by which a utility could make corrections and adjust for the actual price of the gas supplied and thereby correct the customer rates. The regulated sales rate used to recover the cost of gas was called the gas cost recovery rate (GCRR). Use of the DGA takes into account that, under a regulated gas sales rate, customers pay only the actual costs of the gas consumed by them and **the utility is neither to incur a profit nor suffer a loss** in the course of procuring and selling the gas.

In 1987 parties believed that the DGA would be a temporary feature because the continuing volatility of gas prices was not anticipated. However, contrary to these expectations, the purpose and need for the use of DGAs has continued. Initially, the DGAs were reconciled twice a year on a winter/summer seasonal basis. During the period from 1987 to March 2002, the Board allowed prior seasonal adjustments to be made in reconciliation of the DGA in respect of the preceding same season.

(2006 decision, p. 2, emphasis added, footnote omitted)

187 More examples are found in the Appendix.

3. Loose Later Practices

188 However, ATCO's practices later became lax in a number of respects, and sometimes small adjustments of other types were made in the deferral accounts. That had never been the purpose of the accounts. The Commission described that:

. . . However, the Board [now Commission] is aware that, during the approximate 16 years that the DGA has been in place, it has been used to update adjusted imbalance amounts from shippers, producers and interconnecting pipelines. Prior period adjustments for various types of corrections have been relatively common occurrences. While the Board and interested parties may not have previously taken issue with these types of corrections, the Board is concerned that the DGA seems to have evolved into a vehicle to fix all possible errors as a cost of gas to be charged to sales customers under a regulated rate.

(2005 decision at p. 10, F13)

> . . . **The Board believes that, normally, reconciliations were not expected to look back further than 12 months.** As the process evolved, some prior period adjustments were made which extended back further than 12 months. Under special circumstances, for example, involving measuring equipment malfunctions, prior period adjustments involving longer periods have been accepted by the Board. However, the Board considers that **the DGA was never set up with the intention of permitting all prior period accounting errors**, particularly those that would have been subject to ATCO's management and control, **to be processed and rectified through the DGA.**
>
> **The Board is troubled by the evolutional use of the DGA. The DGA replaced a prospective process where accounting errors, such as those that are the subject of the Application, should typically have been absorbed by the utility's shareholder.** It now appears that the DGA is being treated as a catch-all for fixing errors, including those that have a long history, or appear to be the result of human error, where adequate processes have not been in place to capture and correct the problem at an early stage. Notwithstanding that some prior period adjustments previously approved by the Board may have covered an extended period of time, the Board considers that **seven years represents a significant lag presenting obvious intergenerational equity issues.**
>
> (*id.* at p. 11, F14, emphasis added)

4. Calgary's Argument

189 Calgary's factum and book of authorities cite or quote past Commission orders fully confirming the Commission's recitals quoted above (in subparts 2, 3). The appellant also shows that those accounts were promptly reconciled to allow for errors in prediction, and that the Commission gave orders replacing the interim rates initially established with final rates reflecting the reconciliations. After some years, that was done monthly (based on a three-month rolling average).

190 In written argument filed with the Commission on its 2008 application, ATCO had objected that the Commission should not see a full history of its own orders governing the deferred gas account. That objection is hard to reconcile with the arguments which ATCO had made to the Court of Appeal in the 2007 appeal (need for a fuller record). However, ATCO did not object to that evidence in this new appeal. (ATCO's original argument to the Commission that ATCO lacked time to check old Commission decisions was not made again to the Court of Appeal, and of course became moot long ago.)

191 Old Commission decisions are not exactly evidence (not really fact) and are not much (if at all) law. They are previous process, and are all about the same utility (or its two predecessors). They are not tendered here to prove facts, but for their directions and decisions.

192 In the present appeal, the appellant Calgary, the respondent ATCO, and the Commission itself, all reproduced old Commission decisions in their various books of authorities.

193 Any court can look at its own previous decisions and records. See *Kin Franchising Ltd. v. Donco Ltd.* (1993), 7 Alta. L.R. (3d) 313 (Alta. C.A.), 316 (para. 7); *Alberta Evidence Act*, R.S.A. 2000, c. A-18, s. 42. Additional authorities are found in 3 Stevenson & Côté, *Civil Procedure Encyclopedia*, p. 45-54 (ch. 45, Pt. Z.3) (2003). I see no reason to withhold that power from a formal tribunal like this Commission (with all its powers). See the *Alberta Utilities Commission Act*, 2007, c. A-37.2, s. 11, and cf. *Germain v. Saskatchewan (Automobile Injury Appeal Commission)*, 2009 SKQB 106, [2009] 7 W.W.R. 509 (Sask. Q.B.). Especially when the tribunal is an ongoing regulator with constant applications over the rates and accounts of the same handful of companies. This Commission has looked at its previous decisions for many many years. A classic decision of the Supreme Court of Canada says that the Commission can get its information in whatever mode it sees fit: *Edmonton (City) v. Northwestern Utilities Ltd.*, [1929] S.C.R. 186 (S.C.C.), 193. And if the Commission can take notice, why cannot the Court of Appeal take such judicial notice on appeal from the Commission?

194 Furthermore, it was ATCO itself which began all this, and its application to that end expressly submitted that the Commission should make the "adjustments" (surcharges) to consumers by looking back to the Commission's old

approval of DGAs. (See ATCO's application of May 31, 2004, § 4.1 "History", present Commission Record Tab 1, pp. 4-5.)

195 Therefore, it is not surprising that the Commission did *not* decline to look at any previous decisions by itself. Instead it recited and quoted a number of them in its 2005 original decision, and in its 2008 decision reconsidering that. The Commission did *not* say (in 2005 or 2008) that it (or Calgary) lacked evidence about this.

196 The Commission's public website gives ready access to some decisions from 1996 to 1999, and many thereafter. Quicklaw also reports its decisions from 2002. Print copies of all Commission decisions (to 1999) are available in one Law Society Library and (to 2008) in the Alberta Government Library. (The University of Alberta law library has some Commission decisions.) The Commission will supply copies on request. So the text of past decisions is not open to doubt. Anyone can access them to check the accuracy of quotations or summaries.

197 Therefore, the Commission was correct to inspect its past decisions on DGAs. I have amplified my recitals of this history by quoting two or three additional passages from old Commission decisions (pointed out by ATCO in its October 12, 2007 argument, Tab 64, p. 3, quoting decision 2005-036). I have also described some additional passages from Calgary's argument of October 5, 2007 to the Commission (Tab 61): see an Appendix to this judgment. The description has been checked against the original Commission decisions.

198 In any event, the old controversy about taking notice of the former Commission orders has no effect on the result, because those additional references to past orders reinforce but do not change the factual picture painted by the Commission itself in the 2008 decision now under appeal.

F. The Bell Telephone Decision of the Supreme Court of Canada

1. Introduction

199 Counsel cited *Bell Canada v. Canadian Radio-Television & Telecommunications Commission*, 2009 SCC 40, [2009] 2 S.C.R. 764 (S.C.C.). It involved telephone companies' infrastructure under federal legislation.

2. Legislation

200 The Canadian Radio-television and Telecommunications Commission no longer regulates telephones under traditional rate-regulating legislation. Now it must follow Canada's *Telecommunications Act*, 1993 c. 38, whose objectives, duties, and powers are vastly broader, and cover more than telephones.

201 I will outline some features of the *Telecommunications Act*, which have no equivalent in Alberta's 1999-2007 legislation applicable to gas utilities or their rates (the *Alberta Energy and Utilities Board Act*, the *Gas Utilities Act*, and the *Public Utilities Act*.)

202 The *Telecommunications Act* imposes on the C.R.T.C. a mandatory duty to implement a number of very wide and deep policy objectives when it exercises any of its powers or performs any of its duties (s. 47(a)). Among those mandatory objectives are to

- safeguard, enrich and strengthen the social and economic fabric of Canada . . . (s. 7(a))
- enhance . . . efficiency and competitiveness, at the national and international levels . . . (s. 7(c))
- promote . . . ownership and control . . . by Canadians. (s. 7(d))
- promote the use of Canadian transmission facilities . . . within Canada . . . and points outside . . . (s. 7(e))
- foster increased reliance on market forces . . . (s. 7(f))

• stimulate research and development . . . and encourage innovation . . . (s. 7(g))

• respond to the economic and social requirements of users . . . (s. 7(h))

• contribute to the protection of . . . privacy (s. 7(i))

203 The C.R.T.C. also has unusual statutory powers. It can require any telecommunications company to provide any service in any manner (s. 35(1)) or to construct any facility (s. 42(1)). And (most apposite here), the Commission can require the company to "contribute . . . to a fund to support continuing access by Canadians." (s. 46.5(1)). Therefore the C.R.T.C. has positive proactive duties going far beyond fair prices (rates), reliability of service and supply, or even safety, of one company.

3. The Supreme Court's Decision

204 The Supreme Court of Canada (and the Federal Court of Appeal) confirmed the C.R.T.C.'s decision to follow a scheme which it ordered a few years before. That was not to reduce excessive phone rates (for competition reasons), but instead to hold a portion of the revenue in profitable urban markets in a special account to be later spent on infrastructure improvements to benefit consumers.

4. Is the Supreme Court of Canada Decision Distinguishable?

205 I have concluded that the *Bell* decision can and should be distinguished here, for the following eight reasons.

(a) Different Legislative Objectives and Powers and History

206 The Supreme Court of Canada itself expressly distinguished Alberta's *Gas Utilities Act* and said that the federal C.R.T.C. has broader objectives and power than does Alberta's Commission. See the *Bell* case, paras. 17, 22, 36, 39-43, 45-48, 50-53, 55, 57, 72, 74-75 and 77. The Supreme Court of Canada even distinguishes decisions about the C.R.T.C. in earlier years when that tribunal was governed by the more traditional type of rate-of-return regulation like the Alberta system. (In those days the old system was mandated for telephone companies by the *Railway Act*.) See the *Bell* decision at paras. 39-46, and 62. See subpart 2 above. To the same effect is para. 41 of the Federal Court of Appeal decision (2008 FCA 91 (F.C.A.)) which the Supreme Court of Canada affirmed.

207 In particular, the Supreme Court of Canada pointed out that traditional rate regulation is a two-way contest between the interests of the utility company and its particular consumers. The C.R.T.C. (on the other hand) has to meet objectives for all Canadians in all parts of Canada, e.g. fostering competition: see paras. 45 and 47. What is in issue in the present dispute between Calgary and ATCO is the limited traditional type of rate-making power. See the precise passages in Court of Appeal and Supreme Court of Canada decisions, describing and mandating that Alberta scheme, quoted in Parts C and D above.

208 The present ATCO appeal is about a price (rate or revenue) fair as between the utility and the consumer; nothing more. Though the *Bell* decision's origin had a little to do with such questions, the actual *Bell* decision was about increasing access and competition, and dictating to the various telephone companies compulsory long-term infrastructure competition.

209 See also subpart (b) below, on "price-cap regulation".

210 There is an even more striking distinction between the C.R.T.C. and Alberta's Commission. For most of its history, the Commission has been separate from the Energy Resources Conservation Board. The rate regulator, the Alberta Utilities Commission, is now again separate. The broader policy about the industry and its physical form is no part of the Commission's functions, as illustrated by the Genesee power plant decision: *Alberta Power Ltd. v. Alberta (Public Utilities Board)* (1990), 102 A.R. 353 (Alta. C.A.). Though the Energy Resources Conservation Board had decided that

the new second Genesee power plant was needed and gave a permit to build it, after the plant was built, the Public Utilities Board (now the Commission) could and properly did exclude it from the rate base as not "used or required to be used".

211 Alberta's two tribunals were temporarily merged effective February 15, 1995 (by 1994 c. A-19.5). But the merger ended effective January 1, 2008 (by 2007 c. A-37.2), before the decision under appeal. Furthermore, the *legislation* for the two tribunals remained separate even during the period of the merged tribunal, 1995-2007.

212 See also *Barrie Public Utilities v. Canadian Cable Television Assn.*, 2003 SCC 28, [2003] 1 S.C.R. 476, 225 D.L.R. (4th) 206 (S.C.C.), (paras. 9-19).

(b) Different Purposes for Setting Up Deferred Accounts

213 I must stress that in *Bell*, the C.R.T.C. was using an entirely new type of utility regulation (invented in the United Kingdom in the 1980s). It is called price-cap regulation. Unlike traditional rate (price) regulation, this does *not* fix rates; in order to give incentives, it merely sets a maximum and makes sophisticated allowances for the result. The difference between the two types of regulation is explained by Netz, *loc. cit. supra*, at 417 ff., especially p. 425-28.

214 One cannot just look at the title of an account, or fixate upon a name like "deferred". One must find the purpose and operation of the account in question. See Part D.8 above.

215 From the outset, the account described in the *Bell* decision was designated expressly to decide later who would own or use the money contained in it. See the Supreme Court of Canada decision, paras. 6, 8-9, 22 (and the Federal Court of Appeal's paras. 43 and 52.) That surplus sum was expected to arise, and did arise, from continuing to charge high urban rates, despite a new theoretical or tentative cap on rates. The difference (surplus) was to be collected and held in the new fund (account) (para. 6). That was a scheme very different from the Alberta fixed-rate scheme. Too many such statements in the Supreme Court's *Bell* decision emphasize the fund's very different purpose to list them fully; some are found in its paras. 37, 57, 61, 63, 64, 66, and 67.

216 The Alberta accounts (DGAs) had very different purposes. They came from an old short-term system for handling very unpredictable raw material costs (gas field prices). It seems to have been an accident, oversight or happenstance (not a Commission order) that they lasted for years. See the detailed history above in Part E.

(c) Alberta Balance Was Largely the Product of a Single "Adjustment" Entered After the Fact Years Later, not an Ongoing Thing

217 Alberta's deferral account had already been reconciled years earlier, i.e. settled. I doubt that it still "existed" in any real sense in 2004, still less that the 1998 or 1999 parts did. Revisiting the old Alberta deferral account was just a device invented years later when a longstanding and ongoing error was finally discovered: see Parts B.1, 2 and 3(a), and D.3 and D.8 above. Here the Commission let the utility use an old account which had been set up for one temporary purpose to be used for a totally different purpose than that contemplated before.

218 Conversely, in the *Bell* case, the C.R.T.C. managed an existing fund of money growing steadily. The C.R.T.C. largely and in principle confirmed its original purpose.

(d) Encumbered Fund vs. Deficit

219 The *Bell* judgment and C.R.T.C. order were a final decision about ownership of surplus funds which previously had encumbered or provisional ownership. See the Supreme Court of Canada decision, paras. 63, 65.

220 However, ATCO's account was on balance (and entirely in the south) a deficit, not a surplus. A deficit cannot have an owner, nor be encumbered. Still less was any deficit intended or ordered to have either here.

(e) Limited Term in Bell

221 The *Bell* account had a definite beginning and end, forecast at the outset (2001-7 but later ended early, in 2006). See the Supreme Court of Canada decision, para. 9, cf. paras. 10-13.

222 In *Bell*, the rates were confirmed and adjusted once and for all, to prevent any further accumulations of reserve funds. The fund (account) was to be closed out and cease to exist: see the Supreme Court of Canada decision, paras. 13 and 15 end.

223 But the Alberta Commission's 2005, 2006, and 2008 decisions allowed the old gas companies' deferred accounts to be available in future to do it all again (though usually not beyond two years). See Part B.3 above.

(f) The Bell Rates Were in Effect Interim, Whereas ATCO's Were Final

224 This is stated by the Federal Court of Appeal's decision, paras. 50-52, and by the Supreme Court of Canada's decision, para. 61.

(g) Bell was Confined to Certain Geographic Areas

225 The funds in the telephone companies' deferred accounts were confined to excess revenue in geographic areas where more competition was needed. Structural changes were needed and so the C.R.T.C. authorized them. Those areas were residential local services in non-high-cost serving areas basket (mostly urban): see *Bell* paras. 4, 6, 10. But in the present ATCO appeal, all (later) gas customers simply got a retroactive rate increase (or refund).

(h) Bell Refunds were Incidental

226 In principle, the C.R.T.C. ordered the telephone companies to spend all the reserved segregated funds on service improvements (handicapped services and more broad-band capacity). Refunds to customers were just incidental amounts which could not be spent: see the Supreme Court of Canada's decision, paras. 14, 15, and 20.

227 But the only use or remedy even suggested before Alberta's rate-making Commission was a second charge (or refund) to the customers for the same old gas long since consumed.

G. Other Distinguishable Decisions

228 The Commission's decision and some factums cited *Epcor Generation Inc. v. Alberta (Energy & Utilities Board)*, 2003 ABCA 374, 346 A.R. 281 (Alta. C.A.) (one J.A.). Note that a power to change rates retroactively there was conceded; here it is in issue. The rate was agreed there to be interim (paras. 12, 14, 15), not final as here. Calgary's argument to the Commission in the present case (October 12, 2007, Tab 65, p. 2) quotes statements by the Commission in *Epcor* confirming that. The proposed dispute on which leave was sought was only over details, indeed unique sharing ratios (*Epcor*, para. 13), not retroactivity itself as here (paras. 9-10). That motion dealt with a defined time and topic only: the 2000 pool price of electricity. And many issues were factual (paras. 23 ff.). It was a decision by only one Justice of Appeal on a motion for leave, not an appeal. *Epcor* is not on point.

229 One other case cited is *Newfoundland (Board of Commissioners of Public Utilities), Re* (1998), 164 Nfld. & P.E.I.R. 60 (Nfld. C.A.). This was a split decision. It involved Newfoundland legislation on regulation of electric utilities. Except for the broad outlines, that legislation bears no resemblance to Alberta legislation regulating gas activity rates.

230 The majority of the Newfoundland Court of Appeal held that setting a rate of return for a utility was not just a step in calculations leading to fixing rates (prices). They held that it set a ceiling for rate of return, and if the later actual rate of return exceeded that ceiling, the Commission could later adjust rates to offset that. Such a rate-of-return ceiling enforced later is emphatically not the Alberta practice or legislation. Nor can I reconcile that view with the Supreme Court of Canada's later decision in the *Stores Block* case, *supra*. Indeed the Newfoundland Court of Appeal largely proceeded on its own interpretation of its legislation, and scarcely mentioned any of the Supreme Court of Canada

decisions cited above (and none of the Alberta Court of Appeal decisions). I do not find the majority decision persuasive. It is distinguishable, in any event.

H. Standard of Review

1. Conflicting Precedents on This

231 First, the Supreme Court of Canada held that the standard of review was correctness: *Barrie Public Utilities v. Canadian Cable Television Assn.*, 2003 SCC 28, [2003] 1 S.C.R. 476, 225 D.L.R. (4th) 206 (S.C.C.), (paras. 9-19). Then it gave a somewhat different decision, as follows. Whether the Commission has a given power is determined on appeal on the standard of correctness, but if it is found to have that power, the actual method used to carry out the power attracts a more deferential approach: "*Stores Block*" case, *ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board)*, 2006 SCC 4, [2006] 1 S.C.R. 140, 344 N.R. 293, 380 A.R. 1 (S.C.C.).

232 I am reluctant to try to create my own *Pushpanathan* analysis here, and then use it to decide which Supreme Court of Canada decision to follow, or to try to distinguish one of the Supreme Court of Canada decisions.

2. Standard Does Not Matter Here

233 Nor need I do so here, for it would not affect the result. Even on the reasonableness tests, the decision of the Commission under appeal is unreasonable and does not survive. That is so for the reasons given in Part D.10 ("Conclusion") and Part F above. None of those topics is discretionary. The legal limits here are statutory or based on binding precedent, and go to the very nature of the process. The errors are fundamental, and ones of basic principle. Parts D.4, D.5 and D.6 show that. The Commission cannot be acting reasonably when it departs from the fundamental principles laid down by the Legislature and the courts for the Commission to follow. It did depart seriously here, and its decision is unreasonable. See also Part D.9 above.

I. Conclusion

234 It is now about 12 years since the accounting errors in question began, and about six years since ATCO sought relief from the Commission. The Commission has held three hearings on the topic and has declined to hear more evidence. I would fear denying justice by delaying justice, were we merely to tell the Commission to reconsider the topic in yet a fourth hearing.

235 I would have allowed the appeal, and vacated so much of the Commission's 2005 and 2008 orders as allows the (southern) recovery of former costs or expenses. I would have directed the Commission under the *Alberta Utilities Commission Act* s. 29(14), that the law requires it to dismiss that part of ATCO's application entirely. There was no appeal, nor leave to appeal from the (northern) rebate to consumers.

236 I would have awarded costs of the appeal to the City appellant payable by ATCO. There should be no costs to or from the Commission, even though its factum went rather far into the merits. But I would caution the Commission that doing that endangers its position in various respects. See *Northwestern Utilities Ltd., Re*, [1979] 1 S.C.R. 684 (S.C.C.), 708-09, paras. 36-37.

J. Procedure

237 The appeal book contains a fuzzy scan of the three Commission decisions in question, and of some court orders. In future, documents should either be printed from electronic copies, or sharp photostats should be made from originals. In contrast, the Commission's filed record has perfect clarity.

238 The Commission filed one copy of its record, as directed by s. 29(10) of the *Alberta Utilities Commission Act*. Rule 537.1 then contemplates that counsel for the appellant will file multiple copies of Extracts of Key Evidence to supplement the Appeal Digest, reproducing only those parts of the full record that are needed (by all parties) to dispose of the appeal.

If the appellant overlooks including something, the respondent can also file Extracts of Key Evidence. No party filed any extracts here. A panel contains three justices, usually based in two different cities, so the absence of individual sets of Extracts hinders the efficient disposition of the appeal.

239 The appellant's citations of court cases included no reported citation. That violates the Consolidated Practice Directions, para. D.1(b). In future it would help this Court to have at least one publisher's (or website) citation (as well as the neutral cite).

Appeal allowed; matter referred to board for reconsideration.

Appendix

More History of Deferred Gas Accounts

N.W.U.L. = Northwestern Utilities

C.W.N.G. = Canadian Western Natural Gas

1987	Orders E87051 and E87052 (July 3): Commission approved in principle applications by ATCO's predecessors to establish a Deferred Gas Accounting and Reconciliation procedures, to be in place until cost of buying gas could be forecast with reasonable certainty.
1988	Decision E88018 and Order E88019 (March 18): Commission held (on N.W.U.L. and C.W.N.G. rates) that the Gas Cost Recovery Rate was interim and would change at least two times/year. Seasonal rates were to be established, but the Commission would monitor the reconciliations more frequently: monthly. The actual review and finalization would be done two times each year. The cumulative actual balance in the DGA on each March 31 and each October 31 would be refunded to or collected from customers through the GCRRs in the ensuing season.— Thereafter in 1988 further Commission orders did reconcile those accounts two times/year for each gas company.
1989-1991	Further Commission orders also in effect reconciled the accounts. Decision C90041 (December 7, 1990) confirmed the system. Some of these orders said that the rates remained subject to review. Interim Order— E89020 (April 4, 1989) said that DGA balances should be minimized, and so any significant increase in gas supply costs between normal application dates should lead to an application by C.W.N.G. for a change in the GCRR.
1994-1997	By Decision 94072 (October 28, 1994) DGA reconciliations for C.W.N.G. were to be annual, not semi-annual. GCRRs were from time to time approved. Order U97010 (January 16, 1997) quoted and reiterated Order 89020 (of April 4, 1989), which in turn summarized Order 88018. Order U97052 (May 7, 1997) re C.W.N.G. said that the DRA calculation method meant that under- or over-recovery in one-half year cumulated in the DGR would be collected or refunded in the next one-half year's period, given normal weather and accuracy of sales forecasts. This would substantially maintain intergenerational equity. Order U97053 (May 7, 1997) for N.W.U.L. gave final approval of the company's GCRR for 2-1/2 months. Decisions U97129 and U97130 (October 31, 1997): Commission reconciled C.W.N.G.'s and N.W.U.L.'s actual gas cost recoveries.
1998	Decision U98067 (April 13) accepted C.W.N.G.'s reconciliation and refused requests to re-examine the DGA process. Order U98071 (May 4) confirmed C.W.N.G.'s summer GCRR as final.
1999-2000	Various interim orders. Order U2000-161 (April 17) made ATCO Gas-South's GCRR final. More interim orders made for both companies. Order U2000-308 (October 27) deferred acceptance of ATCO North's (former N.W.U.L.'s) reconciliation and set a new interim rate.
2001	Order U2001-001 (January 24) left GCRR rates for ATCO South as interim. Order U2001-002 (January 24) was similar for ATCO North. Order U2001-061 (March 28) was similar; as were Orders 2001-062 (March 28) and U2001-448 (December 14).— In 2001 the Commission held a hearing re methods to set the GCRR. Decision 2001-075 (October 30) (on methodology) described the existing procedures (reconciliation two times/year)

	(pp. 3-4), but noted the DGA balances had become large. The Commission decided (p. 64) to switch to monthly written reconciliations to minimize DGA balances. A three-month rolling period would be used for reconciliations.
2002	Decision 2002-026 (April 18) (p. 3) recited the Commission's duty and power to fix "the appropriate final share of the deferral account balances due from each customer class". On p. 4 the Commission said it had been hoped under- and over- recoveries in the DGA would balance out but unexpectedly they had not. But in principle, rates should be established prospectively.
2003	Decision 2003-106 (December 18) (p. 135) said that for the DGA and reconciliation the GCFR would be revised monthly.

Footnotes

1 "Board" means the regulator of Alberta's gas industry which has, over time, been the Public Utilities Board, the Energy and Utilities Board and the Alberta Utilities Commission.

2 Calgary did not challenge the adjustments the Board approved to ATCO's northern territory DGA arising from transportation imbalances for the 1998 - 2004 period (Board factum at para. 14). Accordingly, 1999 (not 1998, as was stated in the leave decision) is the appropriate starting point.

End of Document

Most Negative Treatment: Check subsequent history and related treatments.

2009 SCC 40
Supreme Court of Canada

Bell Canada v. Canadian Radio-Television & Telecommunications Commission

2009 CarswellNat 2717, 2009 CarswellNat 2718, 2009 SCC 40, [2009] 2 S.C.R. 764, [2009] A.C.S. No. 40, [2009] S.C.J. No. 40, 180 A.C.W.S. (2d) 843, 310 D.L.R. (4th) 608, 392 N.R. 323, 92 Admin. L.R. (4th) 157, J.E. 2009-1708

Bell Canada, Appellant v. Bell Aliant Regional Communications, Limited Partnership, Consumers' Association of Canada, National Anti-Poverty Organization, Public Interest Advocacy Centre, MTS Allstream Inc., Société en commandite Télébec and TELUS Communications Inc., Respondents and Canadian Radio-television and Telecommunications Commission, Intervener

TELUS Communications Inc., Appellant v. Bell Canada, Arch Disability Law Centre, Bell Aliant Regional Communications, Limited Partnership, Canadian Radio-television and Telecommunications Commission, Consumers' Association of Canada, National Anti-Poverty Organization, Public Interest Advocacy Centre, MTS Allstream Inc., Saskatchewan Telecommunications and Société en commandite Télébec, Respondents

Consumers' Association of Canada and National Anti-Poverty Organization, Appellants v. Canadian Radio-television and Telecommunications Commission, Bell Aliant Regional Communications, Limited Partnership, Bell Canada, Arch Disability Law Centre, MTS Allstream Inc., TELUS Communications Inc. and TELUS Communications (Québec) Inc., Respondents

McLachlin C.J.C., Binnie, LeBel, Deschamps, Fish, Abella, Charron, Rothstein, Cromwell JJ.

Heard: March 26, 2009
Judgment: September 18, 2009
Docket: 32607, 32611

Proceedings: affirming *Bell Canada v. Canadian Radio-Television & Telecommunications Commission* (2008), 80 Admin. L.R. (4th) 159, 2008 CarswellNat 544, *(*sub nom. *Consumers Association of Canada v. Canadian Radio-Television & Telecommunications Commission)* 375 N.R. 124, 2008 FCA 91, 2008 CarswellNat 2390, 2008 CAF 91 (F.C.A.)

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Subject: Public
Related Abridgment Classifications
Communications law

II Regulatory commissions
II.1 C.R.T.C. (Canadian Radio-television and Telecommunications Commission)
II.1.a Powers and duties
Communications law
IV Telecommunication services
IV.1 Telephone companies
IV.1.a Regulation of rates

Headnote

Communications law --- Regulatory commissions — C.R.T.C. (Canadian Radio-television and Telecommunications Commission) — Powers and duties

In 2002, Canadian Radio-televison and Telecommunications Commission (CRTC) imposed price caps on Bell Canada and other incumbent local exchange carriers — Rather than ordering reduction in rates for certain class of subscribers, CRTC directed carriers to add those amounts to deferral accounts — In 2006, CRTC directed carriers to use funds in deferral accounts for certain specified initiatives and to rebate any balance remaining — Consumer groups appealed part of decision directing initiatives — Appeal was dismissed — CRTC was not limited in setting rates to traditional economic considerations — CRTC was required by s. 47 of Telecommunications Act to consider policy objectives in s. 7 — Creation of deferral accounts and directing initiatives promoted listed policies — Consumer groups appealed — Appeal dismissed — CRTC properly considered objectives set out in s. 7 when it ordered use of deferral accounts for expansion of broadband infrastructure and consumer credits — Improving accessibility services and broadband expansion in rural and remote areas were exactly what CRTC was mandated to do by Act — CRTC had statutory authority to set just and reasonable rates, to establish deferral accounts, and to direct disposition of funds in those accounts.

Communications law --- Telecommunication Services — Telephone companies — Regulation of rates

In 2002, Canadian Radio-televison and Telecommunications Commission (CRTC) imposed price caps on Bell Canada and other incumbent local exchange carriers — Rather than ordering reduction in rates for certain class of subscribers, CRTC directed carriers to add those amounts to deferral accounts — In 2003, CRTC approved rates for those subscribers on final basis — In 2006, CRTC directed carriers to use funds in deferral accounts for certain specified initiatives and to rebate any balance remaining — Bell appealed from part of decision directing rebate — Appeal was dismissed — Decision was not beyond CRTC's jurisdiction as it was not retrospective rate making — 2002 decision entitled CRTC to make order crystallizing Bell's contingent obligation and directing particular expenditure — Rebate was secondary alternative to proposed initiative but was possible use of funds — Rebate did not reduce rates determined to be just and reasonable by 2003 decision — Bell appealed — Appeal dismissed — CRTC's creation and use of deferral accounts for broadband expansion and consumer credits was authorized by Telecommunications Act — Section 7 of Act set out broad telecommunications policy objectives and s. 47(a) directed CRTC to implement policy objectives when exercising its statutory authority — Balancing interests of consumers, carriers and competitors, and pursuing those policy objectives by exercising its rate-setting power was what s. 47 required CRTC to do in setting rates — CRTC acted reasonably and in accordance with Act when it ordered subscriber credits and approved use of funds for broadband expansion — There was no inappropriate cross-subsidization between residential telephone services and broadband expansion — Section 38 set out broad telecommunications policy objectives and directed CRTC to implement them in exercise of its statutory authority.

Droit des communications --- Organismes de réglementation — CRTC (Conseil de la radiodiffusion et des télécommunications canadiennes) — Pouvoirs et obligations

En 2002, le Conseil de la radiodiffusion et des télécommunications canadiennes (CRTC) a imposé un plafonnement à Bell Canada et d'autres entreprises de services locaux titulaires — CRTC a ordonné aux entreprises d'ajouter ces montants dans des comptes de report plutôt que d'ordonner une réduction tarifaire pour une classe particulière d'abonnés — En 2006, le CRTC a ordonné aux entreprises d'utiliser les montants se trouvant dans les comptes de report pour financer certaines initiatives spécifiques et de remettre tout solde résiduel sous forme de rabais — Groupes de consommateurs ont interjeté appel à l'encontre de la partie de la décision portant sur les initiatives — Appel a été rejeté — CRTC n'était pas contraint de fixer les tarifs selon des considérations économiques traditionnelles — CRTC avait l'obligation, en vertu de l'art. 47 de la Loi sur les télécommunications, de prendre en considération les objectifs de politique énoncés à l'art. 7 — Création de comptes de report et l'ordonnance d'initiatives participaient à la mise en oeuvre des politiques énumérées — Groupes de consommateurs ont formé un pourvoi — Pourvoi rejeté — CRTC a correctement tenu compte des objectifs énoncés à l'art. 7 quand il a ordonné l'affectation des montants se trouvant dans les comptes de report à l'expansion du service à large bande et au versement de crédits aux consommateurs — Amélioration des services d'accessibilité et l'expansion des services à large bande dans les régions rurales et éloignées se trouvaient au coeur du mandat confié au CRTC par la Loi — CRTC avait, en vertu de la loi, le pouvoir de fixer des tarifs justes et raisonnables, d'établir des comptes de report et de prescrire de quelle manière devaient être utilisés les fonds de ces comptes.

Droit des communications --- Services de télécommunication — Compagnies de téléphone — Réglementation des tarifs En 2002, le Conseil de la radiodiffusion et des télécommunications canadiennes (CRTC) a imposé un plafonnement à Bell Canada et d'autres entreprises de services locaux titulaires — CRTC a ordonné aux entreprises d'ajouter ces montants dans des comptes de report plutôt que d'ordonner une réduction tarifaire pour une classe particulière d'abonnés — En 2003, le CRTC a approuvé les tarifs pour ces abonnés à titre définitif — En 2006, le CRTC a ordonné aux entreprises d'utiliser les montants se trouvant dans les comptes de report pour financer certaines initiatives spécifiques et de remettre tout solde résiduel sous forme de rabais — Bell a interjeté appel à l'encontre de la partie de la décision portant sur le rabais — Appel a été rejeté — CRTC n'a pas outrepassé sa compétence en rendant une décision portant sur une tarification qui n'était rétrospective — Décision de 2002 permettait au CRTC de rendre une ordonnance actualisant l'obligation éventuelle de Bell et prescrivant des dépenses déterminées — Rabais était une formule de rechange aux initiatives proposées et était un usage potentiel des fonds — Rabais ne réduisait pas les taux jugés justes et raisonnables dans la décision de 2003 — Bell a formé un pourvoi — Pourvoi rejeté — Création et l'utilisation des comptes de report par le CRTC aux fins d'expansion du service à large bande et de versement de crédits aux consommateurs étaient autorisées par les dispositions de la Loi sur les télécommunications — Article 7 de la Loi énonçait certains des grands objectifs de la politique canadienne de télécommunication et l'art. 47a) enjoignait au CRTC de veiller à leur réalisation dans l'exercice des pouvoirs qui lui sont conférés en vertu de la Loi — Conciliation des intérêts des consommateurs, des entreprises et de leurs concurrents, et la poursuite des objectifs de la politique, au moyen de l'exercice de son pouvoir de tarification, constituait précisément ce que l'art. 47 demandait au CRTC de faire en fixant les tarifs — CRTC a agi de façon raisonnable et en conformité avec la Loi lorsqu'il a ordonné l'attribution de crédits aux abonnés et lorsqu'il a approuvé l'utilisation des fonds pour l'expansion du service à large bande — Il n'y a pas eu interfinancement inapproprié entre les services téléphoniques résidentiels et l'expansion du service à large bande — Article 38 énonçait certains des grands objectifs de la politique canadienne de télécommunication et enjoignait au CRTC de veiller à leur réalisation dans l'exercice des pouvoirs qui lui sont conférés par la loi.

The Canadian Radio-televison and Telecommunications Commission (CRTC) imposed price caps for certain services on Bell Canada and other incumbent local exchange carriers in 2002. The CRTC directed carriers to add those amounts to deferral accounts rather than ordering a reduction in rates for a certain class of subscribers. In 2003, the CRTC approved rates for those subscribers on a final basis. In 2006, the CRTC directed carriers to use the funds in the deferral accounts for certain specified initiatives and to rebate any balance remaining. Bell appealed from the part of the decision directing the rebate. The appeal was dismissed. The Federal Court of Appeal found that the decision was not beyond the CRTC's jurisdiction as it was not retrospective rate making. The 2002 decision entitled the CRTC to make the order crystallizing Bell's contingent obligation and directing a particular expenditure. The rebate was a secondary alternative to the proposed initiative, but was a possible use of the funds. The rebate did not reduce rates determined to be just and reasonable by the 2003 decision. Bell appealed.

Held: The appeal was dismissed.

The CRTC properly considered the objectives set out in s. 7 of the Telecommunications Act when it ordered the use of the deferral accounts for the expansion of broadband infrastructure and consumer credits. Improving accessibility services and broadband expansion in rural and remote areas through deferral accounts were exactly what the CRTC was mandated to do by the Act. The CRTC had the statutory authority to set just and reasonable rates, to establish the deferral accounts, and to direct the disposition of the funds in those accounts.

The CRTC's creation and use of the deferral accounts for broadband expansion and consumer credits was authorized by the Act. Section 7 of the Act set out broad telecommunications policy objectives and s. 47(a) directed the CRTC to implement the policy objectives when exercising its statutory authority. Balancing the interests of consumers, carriers and competitors, and pursuing those policy objectives by exercising its rate-setting power was what s. 47 required the CRTC to do. The CRTC acted reasonably and in accordance with the Act when it ordered subscriber credits and approved the use of funds for broadband expansion. There was no inappropriate cross-subsidization between residential telephone services and broadband expansion. Section 38 set out broad telecommunications policy objectives and directed the CRTC to implement them in the exercise of its statutory authority. A wide range of methods were available to the CRTC in determining what is a just and reasonable rate under s. 27. The CRTC also had the power to force carriers to use any accounting method under s. 37.

The encumbered revenues in the deferral accounts were not the variation of final rates. It was always known that the balances of those accounts were subject to the CRTC's direction. A deferral account would have no meaning if the CRTC did not also have the power to order its disposition. The CRTC had the authority to order the disposition of the accounts in the exercise of its rate-setting power as long as that exercise was reasonable.

Le Conseil de la radiodiffusion et des télécommunications canadiennes (CRTC) a imposé un plafonnement des prix pour certains services offerts par Bell Canada et d'autres entreprises de services locaux titulaires en 2002. Le CRTC a ordonné aux entreprises d'ajouter ces montants dans des comptes de report plutôt que d'ordonner une réduction tarifaire pour une classe particulière d'abonnés. En 2003, le CRTC a approuvé les tarifs pour ces abonnés à titre définitif. En 2006, le CRTC a ordonné aux entreprises d'utiliser les montants se trouvant dans les comptes de report pour financer certaines initiatives spécifiques et de remettre tout solde résiduel sous forme de rabais. Bell a interjeté appel à l'encontre de la partie de la décision portant sur le rabais. L'appel a été rejeté. La Cour d'appel fédérale a conclu que le CRTC n'avait pas outrepassé sa compétence en rendant une décision portant sur une tarification qui n'était pas rétrospective. La décision de 2002 permettait au CRTC de rendre une ordonnance actualisant l'obligation éventuelle de Bell et prescrivant des dépenses déterminées. Le rabais était une formule de rechange aux initiatives proposées et était un usage potentiel des fonds. Le rabais ne réduisait pas les taux jugés justes et raisonnables dans la décision de 2003. Bell a formé un pourvoi.

Arrêt: Le pourvoi a été rejeté.

Le CRTC a correctement tenu compte des objectifs énoncés à l'art. 7 de la Loi sur les télécommunications quand il a ordonné l'affectation des montants se trouvant dans les comptes de report à l'expansion du service à large bande et au versement de crédits aux consommateurs. L'utilisation des comptes de report pour l'amélioration des services d'accessibilité et pour l'expansion des services à large bande dans les régions rurales et éloignées se trouvait au coeur du mandat confié au CRTC par la Loi. Le CRTC avait, en vertu de la loi, le pouvoir de fixer des tarifs justes et raisonnables, d'établir des comptes de report, et de prescrire de quelle manière devaient être utilisés les fonds de ces comptes.

La création et l'utilisation des comptes de report par le CRTC aux fins d'expansion du service à large bande et de versement de crédits aux consommateurs étaient autorisées par les dispositions de la Loi. L'article 7 de la Loi énonçait certains des grands objectifs de la politique canadienne de télécommunication et l'art. 47a) enjoignait au CRTC de veiller à leur réalisation dans l'exercice des pouvoirs qui lui sont conférés en vertu de la loi. La conciliation des intérêts des consommateurs, des entreprises et de leurs concurrents, et la poursuite des objectifs de la politique, au moyen de l'exercice de son pouvoir de tarification, constituait précisément ce que l'art. 47 demandait au CRTC de faire. Le CRTC a agi de façon raisonnable et en conformité avec la Loi lorsqu'il a ordonné l'attribution de crédits aux abonnés et lorsqu'il a approuvé l'utilisation des fonds pour l'expansion du service à large bande. Il n'y a pas eu interfinancement inapproprié entre les services téléphoniques résidentiels et l'expansion du service à large bande. L'article 38 énonçait certains des grands objectifs de la politique canadienne de télécommunication et enjoignait au CRTC de veiller à leur réalisation dans l'exercice des pouvoirs qui lui sont conférés par la loi. Le CRTC disposait de toute une gamme de méthodes afin de déterminer ce qui constituait un tarif juste et raisonnable en vertu de l'art. 27. Le CRTC avait également le pouvoir de forcer les entreprises à utiliser des méthodes ou systèmes comptables en vertu de l'art. 37.

Les revenus mis en réserve dans les comptes de report ne constituaient pas la modification de tarifs définitifs. On a toujours su que les soldes de ces comptes étaient sujets à une ordonnance du CRTC. Un compte de report n'aurait aucune utilité si le CRTC n'avait pas le pouvoir d'ordonner la façon d'en disposer. Le CRTC pouvait, dans l'exercice de son pouvoir de tarification, ordonner l'utilisation de ces comptes, dans la mesure où il exerçait ce pouvoir de manière raisonnable.

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POURVOI à l'encontre d'un jugement publié à *Bell Canada v. Canadian Radio-Television & Telecommunications Commission* (2008), 80 Admin. L.R. (4th) 159, 2008 CarswellNat 544, *(*sub nom. *Consumers Association of Canada v.*

Canadian Radio-Television & Telecommunications Commission) 375 N.R. 124, 2008 FCA 91, 2008 CarswellNat 2390, 2008 CAF 91 (F.C.A.).

***Abella J.*:**

1 The *Telecommunications Act*, S.C. 1993, c. 38, sets out certain broad telecommunications policy objectives. It directs the Canadian Radio-television and Telecommunications Commission ("CRTC") to implement them in the exercise of its statutory authority, balancing the interests of consumers, carriers and competitors in the context of the Canadian telecommunications industry. The issue in these appeals is whether this authority was properly exercised.

2 While distinct questions arise in each of the appeals before us, the common problem is whether the CRTC, in the exercise of its rate-setting authority, appropriately directed the allocation of funds to various purposes. In the Bell Canada and TELUS Communications Inc. appeal, the challenged purpose is the distribution of funds to customers, while in the Consumers' Association of Canada and National Anti-Poverty Organization appeal, the impugned allocation was directed at the expansion of broadband infrastructure. For the reasons that follow, in my view the CRTC's allocations were reasonable based on the Canadian telecommunications policy objectives that it is obliged to consider in the exercise of all of its powers, including its authority to approve just and reasonable rates.

Background

3 The CRTC issued its landmark "Price Caps Decision" [1] in May 2002. Exercising its rate-setting authority, the CRTC established a formula to regulate the maximum prices charged for certain services offered by incumbent local exchange carriers ("ILECs"), who are primarily well-established telecommunications carriers.

4 As part of its decision, the CRTC ordered the affected carriers to create separate accounting entries in their ledgers. These were called "deferral accounts". The funds contained in these deferral accounts were derived from residential telephone service revenues in non-high cost serving areas ("non-HCSAs"), which are mainly urban. Under the formula established by the Price Caps Decision, any increase in the price charged for these services in a given year was limited to an inflationary cap, less a productivity offset to reflect the low degree of competition in that particular market.

5 More specifically, the effect of the inflationary cap was to bar carriers from increasing their prices at a rate greater than inflation. The productivity offset, on the other hand, put downward pressure on the rates to be charged. While market forces would normally serve to encourage carriers to reduce both their costs and their prices, the low level of competition in the non-HCSA market led the CRTC to conclude that an offsetting factor was necessary as a proxy for the effect of competition.

6 Given the countervailing factors at work in the Price Caps Decision formula, there was the potential for a decrease in the price of residential services in these areas if inflation fell below a certain level. Rather than mandating such a decrease, however, the CRTC concluded that lower prices, and therefore the prospect of lower revenues, would constitute a barrier to the entry of new carriers into this particular telecommunications market. It therefore ordered that amounts representing the difference between the rates *actually* charged, not including the decrease mandated by the Price Caps Decision formula, and the rates as *otherwise determined* through the formula, were to be collected from subscribers and recorded in deferral accounts held by each carrier. These accounts were to be reviewed annually by the CRTC. The intent of the Price Caps Decision was, therefore, that prices for these services would remain at a level sufficient to encourage market entry, while at the same time maintaining the pressure on the incumbent carriers to reduce their costs.

7 The principal objectives the CRTC intended the Price Caps Decision to achieve were the following:

a) to render reliable and affordable services of high quality, accessible to both urban and rural area customers;

b) to balance the interests of the three main stakeholders in telecommunications markets, i.e., customers, competitors and incumbent telephone companies;

c) to foster facilities-based competition in Canadian telecommunications markets;

d) to provide incumbents with incentives to increase efficiencies and to be more innovative; and

e) to adopt regulatory approaches that impose the minimum regulatory burden compatible with the achievement of the previous four objectives. [para. 99]

8 The CRTC discussed the future use of the deferral account funds as follows:

The Commission anticipates that an adjustment to the deferral account would be made whenever the Commission approves rate reductions for residential local services that are proposed by the ILECs as a result of competitive pressures. The Commission also anticipates that the deferral account would be drawn down to mitigate rate increases for residential service that could result from the approval of exogenous factors or when inflation exceeds productivity. Other draw downs could occur, for example, through subscriber rebates or the funding of initiatives that would benefit residential customers in other ways.

[Emphasis added; para. 412.]

At the time, it did not specifically direct how the deferral account funds were to be used, leaving the issue subject to further submissions. While some participants objected to the creation of the deferral accounts, no one appealed the Price Caps Decision (*Bell Canada v. Canadian Radio-Television & Telecommunications Commission*, 2008 FCA 91, 375 N.R. 124 (F.C.A.), at para. 14).

9 The Price Caps Decision was to apply to services offered by Bell Canada, TELUS, and other affected carriers for the four-year period from June 1, 2002 to May 31, 2006. In a decision in 2005, the CRTC extended this price regulation regime for another year to May 31, 2007 [2]. The CRTC allowed some draw-downs of the deferral accounts following the Price Caps Decision that are not at issue in these appeals.

10 In March 2003, in two separate decisions, the CRTC approved the rates for Bell Canada and TELUS [3]. In the Bell Canada decision, the CRTC appeared to contemplate the continued operation of the deferral accounts established in the Price Caps Decision. It ordered, for example, that certain tax savings be allocated to the deferral accounts:

The Commission, in Decision 2002-34, established a deferral account in conjunction with the application of a basket constraint equal to the rate of inflation less a productivity offset to all revenues from residential services in non-HCSAs. The Commission considers that AT&T Canada's proposal to allocate the Ontario GRT and the Quebec TGE tax savings associated with all capped services to the price cap deferral account is inconsistent with that determination. The Commission finds that Bell Canada's proposal to include the Ontario GRT and Quebec TGE tax savings associated with the residential local services in non-HCSAs basket in the price cap deferral account is consistent with that determination.

[Emphasis added; para. 32.]

11 On December 2, 2003, Bell Canada sought the approval of the CRTC to use the balance in its deferral account to expand high-speed broadband internet service to remote and rural communities. In response, on March 24, 2004, the CRTC issued a public notice requesting submissions on the appropriate disposition of the deferral accounts [4]. Pursuant to this notice, the CRTC conducted a public process whereby proposals were invited for the disposition of the affected carriers' deferral accounts. The review was extensive and proposals were received from numerous parties.

12 This led to the release of the "Deferral Accounts Decision" on February 16, 2006 [5]. In this decision, the CRTC directed how the funds in the deferral accounts were to be used. These directions form the foundation of these appeals.

13 After considering the various policy objectives outlined in the applicable statute, the *Telecommunications Act*, and the purposes set out in the Price Caps Decision, the CRTC concluded that all funds in the deferral accounts should be targeted for disposal by a designated date in 2006:

> The attachment to this Decision provides preliminary estimates of the deferral account balances as of the end of the fourth year of the current price cap period in 2006. <u>The Commission notes that the deferral account balances are expected to be very large for some ILECs. It also notes the concern that allowing funds to continue to accumulate in the accounts would create inefficiencies and uncertainties.</u>
>
> . . . . .
>
> <u>Accordingly, the Commission considers it appropriate not only to provide directions on the disposition of all the funds that will have accumulated in the ILECs' deferral accounts by the end of the fourth year of the price cap period in 2006, but also to provide directions to address amounts recurring beyond this period in order to prevent further accumulation of funds in the deferral accounts.</u> The Commission will provide directions and guidelines for disposing of these amounts later in this Decision.
>
> [Emphasis added; paras. 58 and 60.]

14 The CRTC further decided that the deferral accounts should be disbursed primarily for two purposes. As a priority, at least 5 percent of the accounts was to be used for improving accessibility to telecommunications services for individuals with disabilities. The other 95 percent was to be used for broadband expansion in rural and remote communities. Proposals were invited on how the deferral account funds should be applied. If the proposal as approved was for less than the balance of its deferral account, an affected carrier was to distribute the remaining amount to consumers.

15 In summary, therefore, the CRTC decided that the affected carriers should focus on broadband expansion and accessibility improvement. It also decided that if these two objectives could be fulfilled for an amount less than the full deferral account balances, credits to subscribers would be ordered out of the remainder. It should be noted that customers were not to be compensated in proportion to what they had paid through these credits because of the potential administrative complexity of identifying these individuals and quantifying their respective shares. Instead, the credits were to be provided to certain current subscribers. Prospective rate reductions could also be used to eliminate recurring amounts in the accounts.

16 At the time, the balance in the deferral accounts established under the Price Caps Decision was considerable. Bell Canada's account was estimated to contain approximately $480.5 million, while the TELUS account was estimated at about $170 million.

17 It is helpful to set out how the CRTC explained its decision on the allocation of the deferral account funds. Referencing the importance of telecommunications in connecting Canada's "vast geography and relatively dispersed population", it stressed that Canada had fallen behind in the adoption of broadband services (at paras. 73-74). It contrasted the wide availability of broadband service in urban areas with the less developed network in rural and remote communities. Further, it noted that the objectives outlined in the Price Caps Decision and in the *Telecommunications Act* at s. 7(*b*) provided for improving the quality of telecommunications services in those communities, and that their social and economic development would be favoured by an expansion of the national broadband network. In its view, this initiative would also provide a helpful complement to the efforts of both levels of government to expand broadband coverage. It therefore concluded that broadband expansion was an appropriate use of a part of the deferral account funds (at paras. 73-80).

18 The CRTC also explained that while customer credits would be consistent with the objectives set out in s. 7 of the *Telecommunications Act* and with the Price Caps Decision, these disbursements should not be given priority because broadband expansion and accessibility services provided greater long-term benefits. Nevertheless, credits effectively

balanced the interests of the "three main stakeholders in the telecommunications markets" (at para. 115), namely customers, competitors and carriers. It concluded that credits did not contradict the purpose of the deferral accounts, and contrasted one-time credits with a reduction of rates. In its view, credits, unlike rate reductions, did not have a sustained negative impact on competition in these markets, which was the concern the deferral accounts were set up to address (at paras. 112-16).

19 A dissenting Commissioner expressed concerns over the disposition of the deferral account funds. In her view, the CRTC had no mandate to direct the expansion of broadband networks across the country. The CRTC's policy had generally been to ensure the provision of a basic level of service, not services like broadband, and she therefore considered the CRTC's reliance on the objectives of the *Telecommunications Act* to be inappropriate.

20 On January 17, 2008, the CRTC issued another decision dealing with the carriers' proposals to use their deferral account balances for the purposes set out in the Deferral Accounts Decision [6]. Some carriers' plans were approved in part, with the result that only a portion of their deferral account balances was allocated to those projects. Consequently, the CRTC required them to submit, by March 25, 2008, a plan for crediting the balance in their deferral accounts to residential subscribers in non-HCSAs.

21 Bell Canada, as well as the Consumers' Association of Canada and the National Anti-Poverty Organization, appealed the CRTC's Deferral Accounts Decision to the Federal Court of Appeal. The Deferral Accounts Decision was stayed by Richard C.J. in the Federal Court of Appeal on January 25, 2008. The decision requiring further submissions on plans to distribute the deferral account balances was also stayed by Sharlow J.A. pending the filing of an application for leave to appeal to this Court on April 23, 2008. Both stay orders were extended by this Court on September 25, 2008. The stay orders do not apply to the funds allocated for the improvement of accessibility for individuals with disabilities.

22 In a careful judgment by Sharlow J.A., the court unanimously dismissed the appeals, concluding that the Price Caps Decision regime always contemplated the future disposition of the deferral account funds as the CRTC would direct, and that the CRTC acted within its broad mandate to pursue its regulatory objectives. For the reasons that follow, I agree with the conclusions reached by Sharlow J.A.

Analysis

23 The parties have staked out diametrically opposite positions on how the balance of the deferral account funds should be allocated.

24 Bell Canada argued that the CRTC had no statutory authority to order what it claimed amounted to retrospective "rebates" to consumers. In its view, the distributions ordered by the CRTC were in substance a variation of rates that had been declared final. TELUS joined Bell Canada in this Court, and argued that the CRTC's order for "rebates" constituted an unjust confiscation of property.

25 In response, the CRTC contended that its broad mandate to set rates under the *Telecommunications Act* includes establishing and ordering the disposal of funds from deferral accounts. Because the deferral account funds had always been subject to the possibility of disbursement to customers, there was therefore no variation of a final rate or any impermissible confiscation.

26 The Consumers' Association of Canada was the only party to oppose the allocation of 5 percent of the deferral account balances to improving accessibility, but abandoned this argument during the hearing before the Federal Court of Appeal. Together with the National Anti-Poverty Organization, it argued before this Court that the rest of the deferral account balances should be distributed to customers in full, and that the CRTC had no authority to allow the use of the funds for broadband expansion.

27 These arguments bring us directly to the statutory scheme at issue.

28 The *Telecommunications Act* lays out the basic legislative framework of the Canadian telecommunications industry. In addition to setting out numerous specific powers, the statute's guiding objectives are set out in s. 7. Pursuant to s. 47(*a*), the CRTC must consider these objectives in the exercise of *all* of its powers. These provisions state:

> **7.** It is hereby affirmed that telecommunications performs an essential role in the maintenance of Canada's identity and sovereignty and that the Canadian telecommunications policy has as its objectives
>
> (a) to facilitate the orderly development throughout Canada of a telecommunications system that serves to safeguard, enrich and strengthen the social and economic fabric of Canada and its regions;
>
> (b) to render reliable and affordable telecommunications services of high quality accessible to Canadians in both urban and rural areas in all regions of Canada;
>
> (c) to enhance the efficiency and competitiveness, at the national and international levels, of Canadian telecommunications;
>
> (d) to promote the ownership and control of Canadian carriers by Canadians;
>
> (e) to promote the use of Canadian transmission facilities for telecommunications within Canada and between Canada and points outside Canada;
>
> (f) to foster increased reliance on market forces for the provision of telecommunications services and to ensure that regulation, where required, is efficient and effective;
>
> (g) to stimulate research and development in Canada in the field of telecommunications and to encourage innovation in the provision of telecommunications services;
>
> (h) to respond to the economic and social requirements of users of telecommunications services; and
>
> (i) to contribute to the protection of the privacy of persons.
>
> . . . . .
>
> **47.** The Commission shall exercise its powers and perform its duties under this Act and any special Act
>
> (a) with a view to implementing the Canadian telecommunications policy objectives and ensuring that Canadian carriers provide telecommunications services and charge rates in accordance with section 27;

The CRTC relied on these two provisions in arguing that it was required to take into account a broad spectrum of considerations in the exercise of its rate-setting powers, and that the Deferral Accounts Decision was simply an extension of this approach.

29 The *Telecommunications Act* grants the CRTC the general power to set and regulate rates for telecommunications services in Canada. All tariffs imposed by carriers, including rates for services, must be submitted to it for approval, and it may decide any matter with respect to rates in the telecommunications services industry, as the following provisions show:

> **24.** The offering and provision of any telecommunications service by a Canadian carrier are subject to any conditions imposed by the Commission or included in a tariff approved by the Commission.
>
> **25.** (1) No Canadian carrier shall provide a telecommunications service except in accordance with a tariff filed with and approved by the Commission that specifies the rate or the maximum or minimum rate, or both, to be charged for the service.
>
> . . . . .

> **32.** The Commission may, for the purposes of this Part,
>
> . . . . .
>
> (*g*) in the absence of any applicable provision in this Part, determine any matter and make any order relating to the rates, tariffs or telecommunications services of Canadian carriers.

30 The guiding rule of rate-setting under the *Telecommunications Act* is that the rates be "just and reasonable", a longstanding regulatory principle. To determine whether rates meet this standard, the CRTC has a wide discretion which is protected by a privative clause:

> **27.** (1) Every rate charged by a Canadian carrier for a telecommunications service shall be just and reasonable.
>
> . . . . .
>
> (3) The Commission may determine in any case, as a question of fact, whether a Canadian carrier has complied with section 25, this section or section 29, or with any decision made under section 24, 25, 29, 34 or 40.
>
> . . . . .
>
> (5) In determining whether a rate is just and reasonable, the Commission may adopt any method or technique that it considers appropriate, whether based on a carrier's return on its rate base or otherwise.
>
> . . . . .
>
> **52.** (1) The Commission may, in exercising its powers and performing its duties under this Act or any special Act, determine any question of law or of fact, and its determination on a question of fact is binding and conclusive.

31 In addition to the power under s. 27(5) to adopt "any method or technique that it considers appropriate" for determining whether a rate is just and reasonable, the CRTC also has the authority under s. 37(1) to order a carrier to adopt "any accounting method or system of accounts" in view of the proper administration of the *Telecommunications Act*. Section 37(1) states:

> **37.** (1) The Commission may require a Canadian carrier
>
> > (a) to adopt any method of identifying the costs of providing telecommunications services and to adopt any accounting method or system of accounts for the purposes of the administration of this Act;

32 The CRTC has other broad powers which, while not at issue in this case, nevertheless further demonstrate the comprehensive regulatory powers Parliament intended to grant. These include the ability to order a Canadian carrier to provide any service in certain circumstances (s. 35(1)); to require communications facilities to be provided or constructed (s. 42(1)); and to establish any sort of fund for the purpose of supporting access to basic telecommunications services (s. 46.5(1)).

33 This statutory overview assists in dealing with the preliminary issue of the applicable standard of review. Although the Federal Court of Appeal accepted the parties' position that the applicable standard of review was correctness, Sharlow J.A. acknowledged that the standard of review could be more deferential in light of this Court's decision in *VIA Rail Canada Inc. v. Canadian Transportation Agency*, 2007 SCC 15, [2007] 1 S.C.R. 650 (S.C.C.), at paras. 98-100. This was an invitation, it seems to me, to clarify what the appropriate standard is.

34 Bell Canada and TELUS concede that the CRTC had the authority to approve disbursements from the deferral accounts for initiatives to improve broadband expansion and accessibility to telecommunications services for persons with disabilities, and that they actually sought such approval. In their view, however, this authority did not extend to what they characterized as retrospective "rebates". Similarly, in the Consumers' appeal the crux of the complaint is with whether the CRTC could direct that the funds be disbursed in certain ways, not with whether it had the authority to direct how the funds ought to be spent generally.

35 This means that for Bell Canada and TELUS appeal, the dispute is over the CRTC's authority and discretion under the *Telecommunications Act* in connection with ordering credits to customers from the deferral accounts. In the Consumers' appeal, it is over its authority and discretion in ordering that funds from the deferral accounts be used for the expansion of broadband services.

36 A central responsibility of the CRTC is to determine and approve just and reasonable rates to be charged for telecommunications services. Together with its rate-setting power, the CRTC has the ability to impose *any* condition on the provision of a service, adopt *any* method to determine whether a rate is just and reasonable and require a carrier to adopt *any* accounting method. It is obliged to exercise all of its powers and duties with a view to implementing the Canadian telecommunications policy objectives set out in s. 7.

37 The CRTC's authority to establish the deferral accounts is found through a combined reading of ss. 27 and 37(1). The authority to establish these accounts necessarily includes the disposition of the funds they contain, a disposition which represents the final step in a process set in motion by the Price Caps Decision. It is self-evident that the CRTC has considerable expertise with respect to this type of question. This observation is reflected in its extensive statutory powers in this regard and in the strong privative clause in s. 52(1) protecting its determinations on questions of fact from appeal, including whether a carrier has adopted a just and reasonable rate.

38 In my view, therefore, the issues raised in these appeals go to the very heart of the CRTC's specialized expertise. In the appeals before us, the core of the quarrel in effect is with the methodology for setting rates and the allocation of certain proceeds derived from those rates, a polycentric exercise with which the CRTC is statutorily charged and which it is uniquely qualified to undertake. This argues for a more deferential standard of review, which leads us to consider whether the CRTC was reasonable in directing how the funds from the deferral accounts were to be used. (See *New Brunswick (Board of Management) v. Dunsmuir*, 2008 SCC 9, [2008] 1 S.C.R. 190 (S.C.C.), at para. 54; *Khosa v. Canada (Minister of Citizenship & Immigration)*, 2009 SCC 12, [2009] 1 S.C.R. 339 (S.C.C.), at para. 25; and *VIA Rail Canada Inc.*, at paras. 88-100.)

39 This brings us to the nature of the CRTC's rate-setting power in the context of this case. The predecessor statute for telecommunications rate-setting, the *Railway Act*, R.S.C. 1985, c. R-3, also stipulated that rates be "just and reasonable" (s. 340(1)). Traditionally, those rates were based on a balancing between a fair rate for the consumer and a fair return on the carrier's investment. (See, e.g., *Edmonton (City) v. Northwestern Utilities Ltd.*, [1929] S.C.R. 186 (S.C.C.), at pp. 192-93 and *ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board)*, 2006 SCC 4, [2006] 1 S.C.R. 140 (S.C.C.), at para. 65.)

40 Even before the expansive language now found in the *Telecommunications Act*, regulatory agencies had enjoyed considerable discretion in determining the factors to be considered and the methodology that could be adopted for assessing whether rates were just and reasonable. For instance, in dismissing a leave application in *General Increase in Freight Rates, Re* (1954), 76 C.R.T.C. 12 (S.C.C.), Taschereau J. wrote:

> [I]f the Board is bound to grant a relief which is just to the public and secures to the railways a fair return, it is not bound to accept for the determination of the rates to be charged, the sole method proposed by the applicant. <u>The obligation to act is a question of law, but the choice of the method to be adopted is a question of discretion with which, under the statute, no Court of law may interfere.</u>
>
> [Emphasis added; p. 13.]

In making this determination, he relied on Duff C.J.'s judgment in *Canadian National Railway v. Bell Telephone Co.*, [1939] S.C.R. 308 (S.C.C.), for the following proposition in the particular statutory context of that case:

> The law dictates neither the order to be made in a given case nor the considerations by which the Board is to be guided in arriving at the conclusion that an order, or what order, is necessary or proper in a given case. True, it is

> the duty of all public bodies and others invested with statutory powers to act reasonably in the execution of them, but the policy of the statue [*sic*] is that, subject to the appeal to the Governor in Council under s. 52, in exercising an administrative discretion entrusted to it, the Board itself is to be the final arbiter as to the order to be made. [p. 315]

(See also Michael H. Ryan, *Canadian Telecommunications Law and Regulation* (loose-leaf ed.), at §612.)

41 The CRTC's already broad discretion in determining whether rates are just and reasonable has been further enhanced by the inclusion of s. 27(5) in the *Telecommunications Act* permitting the CRTC to adopt "any method", language which was absent from the *Railway Act*.

42 Even more significantly, the *Railway Act* contained nothing analogous to the statutory direction under s. 47 that the CRTC must exercise its rate-setting powers with a view to implementing the Canadian telecommunications objectives set out in s. 7. These statutory additions are significant. Coupled with its rate-setting power, and its ability to use any method for arriving at a just and reasonable rate, these provisions contradict the restrictive interpretation of the CRTC's authority proposed by various parties in these appeals.

43 This was highlighted by Sharlow J.A. when she stated:

> Because of the combined operation of section 47 and section 7 of the *Telecommunications Act* ..., the CRTC's rating jurisdiction is not limited to considerations that have traditionally been considered relevant to ensuring a fair price for consumers and a fair rate of return to the provider of telecommunication services. Section 47 of the *Telecommunications Act* expressly requires the CRTC to consider, as well, the policy objectives listed in section 7 of the *Telecommunications Act*. What that means, in my view, is that in rating decisions under the *Telecommunications Act*, the CRTC is entitled to consider any or all of the policy objectives listed in section 7. [para. 35]

44 It is true that the CRTC had previously used a "rate base rate of return" method, based on a combination of a rate of return for investors in telecommunications carriers and a rate base calculated using the carriers' assets. This resulted in rates charged for the carrier's services that would, on the one hand, provide a fair return for the capital invested in the carrier, and, on the other, be fair to the customers of the carrier.

45 However, these expansive provisions mean that the rate base rate of return approach is not necessarily the only basis for setting a just and reasonable rate. Furthermore, based on ss. 7, 27(5) and 47, the CRTC is not required to confine itself to balancing only the interests of subscribers and carriers with respect to a particular service. In the Price Caps Decision, for example, the CRTC chose to focus on maximum prices for services, rather than on the rate base rate of return approach. It did so, in part, to foster competition in certain markets, a goal untethered to the direct relationship between the carrier and subscriber in the traditional rate base rate of return approach. A similar pricing approach was adopted by the CRTC in a decision preceding the Price Caps Decision [7].

46 The CRTC has interpreted these provisions broadly and identified them as responsive to the evolved industry context in which it operates. In its "Review of Regulatory Framework" decision [8], it wrote:

> The Act ... provides the tools necessary to allow the Commission to alter the traditional manner in which it regulates (i.e., to depart from rate base rate of return regulation).
>
> . . . . .
>
> In brief, telecommunications today transcends traditional boundaries and simple definition. It is an industry, a market and a means of doing business that encompasses a constantly evolving range of voice, data and video products and services.
>
> . . . . .

> In this context, the Commission notes that the Act contemplates the evolution of basic service by setting out as an objective the provision of reliable and affordable telecommunications, rather than merely affordable telephone service.
>
> [Emphasis added; pp. 6 and 10.]

47 In *Edmonton (City) v. 360Networks Canada Ltd./London Connect Inc.*, 2007 FCA 106, [2007] 4 F.C.R. 747 (F.C.A.), leave to appeal refused, [2007] 3 S.C.R. vii (note) (S.C.C.), the Federal Court of Appeal drew similar conclusions, observing that the *Telecommunications Act* should be interpreted by reference to the policy objectives, and that s. 7 justified in part the view that the "Act should be interpreted as creating a comprehensive regulatory scheme" (at para. 46). A duty to take a more comprehensive approach was also noted by Ryan, who observed:

> Because of the importance of the telecommunications industry to the country as a whole, rate-making issues may sometimes assume a dimension that gives them a significance that extends beyond the immediate interests of the carrier, its shareholders and its customers, and engages the interests of the public at large. It is also part of the duty of the regulator to take these more far-reaching interests into account. [§604]

48 This leads inevitably, it seems to me, to the conclusion that the CRTC may set rates that are just and reasonable for the purposes of the *Telecommunications Act* through a diverse range of methods, taking into account a variety of different constituencies and interests referred to in s. 7, not simply those it had previously considered when it was operating under the more restrictive provisions of the *Railway Act*. This observation will also be apposite later in these reasons when the question of "final rates" is discussed in connection with the Bell Canada appeal.

49 I see nothing in this conclusion which contradicts the ratio in *Barrie Public Utilities v. Canadian Cable Television Assn.*, 2003 SCC 28, [2003] 1 S.C.R. 476 (S.C.C.). In that case, the issue was whether the CRTC could make an order granting cable companies access to certain utilities' power poles. In that decision, the CRTC had relied on the Canadian telecommunications policy objectives to inform its interpretation of the relevant provisions. In deciding that the language of the *Telecommunications Act* did not give the CRTC the power to grant access to the power poles, Gonthier J. for the majority concluded that the CRTC had inappropriately interpreted the Canadian telecommunications policy objectives in s. 7 as power-conferring (at para. 42).

50 The circumstances of *Barrie Public Utilities* are entirely distinct from those at issue before us. Here, we are dealing with the CRTC setting rates that were required to be just and reasonable, an authority fully supported by unambiguous statutory language. In so doing, the CRTC was exercising a broad authority, which, according to s. 47, it was required to do "with a view to implementing the Canadian telecommunications policy objectives ...". The policy considerations in s. 7 were factors that the CRTC was required to, and did, take into account.

51 Nor does this Court's decision in *ATCO* preclude the pursuit of public interest objectives through rate-setting. In that case, Bastarache J. for the majority, took a strict approach to the Alberta Energy and Utilities Board's powers under the applicable statute. The issue was whether the Board had the authority to order the distribution of proceeds by a regulated company to its subscribers from an asset sale it had approved. It was argued that because the Board had the authority to make "further orders" and impose conditions "in the public interest" on any order, it therefore had the ability to order the disposition of the sale proceeds.

52 In holding that the Board had no such authority, Bastarache J. relied in part on the conclusion that the Board's statutory power to make orders or impose conditions in the public interest was insufficiently precise to grant the ability to distribute sale proceeds to ratepayers (at para. 46). The ability of the Board to approve an asset sale, and its authority to make any order it wished in the public interest, were necessarily limited by the context of the relevant provisions (at paras. 46-48 and 50). It was obliged too to adopt a rate base rate of return method to determine rates, pursuant to its governing statute (at paras. 65-66).

53 Unlike *ATCO*, in the case before us the CRTC's rate-setting authority, and its ability to establish deferral accounts for this purpose, are at the very core of its competence. The CRTC is statutorily authorized to adopt *any* method of determining just and reasonable rates. Furthermore, it is required to consider the statutory objectives in the exercise of its authority, in contrast to the permissive, free-floating direction to consider the public interest that existed in *ATCO*. The *Telecommunications Act* displaces many of the traditional restrictions on rate-setting described in *ATCO*, thereby granting the CRTC the ability to balance the interests of carriers, consumers and competitors in the broader context of the Canadian telecommunications industry (Review of Regulatory Framework Decision, at pp. 6 and 10).

54 The fact that deferral accounts are at issue does nothing to change this framework. No party objected to the CRTC's authority to establish the deferral accounts themselves. These accounts are accepted regulatory tools, available as a part of the Commission's rate-setting powers. As the CRTC has noted, deferral accounts "enabl[e] a regulator to defer consideration of a particular item of expense or revenue that is incapable of being forecast with certainty for the test year" [9] . They have traditionally protected against future eventualities, particularly the difference between forecasted and actual costs and revenues, allowing a regulator to shift costs and expenses from one regulatory period to another. While the CRTC's creation and use of the deferral accounts for broadband expansion and consumer credits may have been innovative, it was fully supported by the provisions of the *Telecommunications Act*.

55 In my view, it follows from the CRTC's broad discretion to determine just and reasonable rates under s. 27, its power to order a carrier to adopt any accounting method under s. 37, and its statutory mandate under s. 47 to implement the wide-ranging Canadian telecommunications policy objectives set out in s. 7, that the *Telecommunications Act* provides the CRTC with considerable scope in establishing and approving the use to be made of deferral accounts. They were created in accordance both with the CRTC's rate-setting authority and with the goal that all rates charged by carriers were and would remain just and reasonable.

56 A deferral account would not serve its purpose if the CRTC did not also have the power to order the disposition of the funds contained in it. In my view, the CRTC had the authority to order the disposition of the accounts in the exercise of its rate-setting power, provided that this exercise was reasonable.

57 I therefore agree with the following observation by Sharlow J.A.:

> The Price Caps Decision required Bell Canada to credit a portion of its final rates to a deferral account, which the CRTC had clearly indicated would be disposed of in due course as the CRTC would direct. There is no dispute that the CRTC is entitled to use the device of a mandatory deferral account to impose a contingent obligation on a telecommunication service provider to make expenditures that the CRTC may direct in the future. <u>It necessarily follows that the CRTC is entitled to make an order crystallizing that obligation and directing a particular expenditure, provided the expenditure can reasonably be justified by one or more of the policy objectives listed in section 7 of the Telecommunications Act.</u>
>
> [Emphasis added; para. 52.]

58 This general analytical framework brings us to the more specific questions in these appeals. In the first appeal, Bell Canada relied on Gonthier J.'s decision *Bell Canada v. Canadian Radio-Television & Telecommunications Commission*, [1989] 1 S.C.R. 1722 (S.C.C.) ("*Bell Canada (1989)*"), to argue that "final" rates cannot be changed and that the funds in the deferral accounts could not, therefore, be distributed as "rebates" to customers.

59 In *Bell Canada (1989)*, the CRTC approved a series of interim rates. It subsequently reviewed them in light of Bell Canada's changed financial situation, and ordered the carrier to credit what it considered to be excess revenues to its current subscribers. Arguing against the CRTC's authority to do so, Bell Canada contended that the CRTC could not order a one-time credit with respect to revenues earned from rates approved by the CRTC, whether the rate order was an interim one or not. Gonthier J. observed that while the *Railway Act* contemplated a positive approval scheme that

only allowed for prospective, not retroactive or retrospective rate-setting, the one-time credit at issue was nevertheless permissible because the original rates were interim and therefore inherently subject to change.

60 In the current case, Bell Canada argued that the rates had been made final, and that the disposition of the deferral accounts for one-time credits was therefore impermissible. More specifically, it argued that the CRTC's order of one-time credits from the deferral accounts amounted to retrospective rate-setting as the term was used in *Bell Canada (1989)*, at p. 1749, namely, that their "purpose is to remedy the imposition of rates approved in the past and found in the final analysis to be excessive" (at p. 1749).

61 In my view, because this case concerns encumbered revenues in deferral accounts (referred to by Sharlow J.A. as contingent obligations or liabilities), we are not dealing with the variation of final rates. As Sharlow J.A. pointed out, *Bell Canada (1989)* is inapplicable because it was known from the outset in the case before us that Bell Canada would be obliged to use the balance of its deferral account in accordance with the CRTC's subsequent direction (at para. 53).

62 It would, with respect, be an oversimplification to consider that *Bell Canada (1989)* applies to bar the provision of credits to consumers in this case. *Bell Canada (1989)* was decided under the *Railway Act*, a statutory scheme that, significantly, did not include any of the considerations or mandates set out in ss. 7, 27(5) and 47 of the *Telecommunications Act*. Nor did it involve the disposition of funds contained in deferral accounts.

63 In my view, the credits ordered out of the deferral accounts in the case before us are neither retroactive nor retrospective. They do not vary the original rate as approved, which included the deferral accounts, nor do they seek to remedy a deficiency in the rate order through later measures, since these credits or reductions were contemplated as a possible disposition of the deferral account balances from the beginning. These funds can properly be characterized as encumbered revenues, because the rates *always* remained subject to the deferral accounts mechanism established in the Price Caps Decision. The use of deferral accounts therefore precludes a finding of retroactivity or retrospectivity. Furthermore, using deferral accounts to account for the difference between forecast and actual costs and revenues has traditionally been held not to constitute retroactive rate-setting (*Epcor Generation Inc. v. Alberta (Energy & Utilities Board)*, 2003 ABCA 374, 346 A.R. 281 (Alta. C.A.), at para. 12, and *Newfoundland (Board of Commissioners of Public Utilities), Re* (1998), 164 Nfld. & P.E.I.R. 60 (Nfld. C.A.), at paras. 97-98 and 175).

64 The Deferral Accounts Decision was the culmination of a process undertaken in the Price Caps Decision. In the Price Caps Decision, the CRTC indicated that the amounts in the deferral accounts were to be used in a manner contributing to achieving the CRTC's objectives (at paras. 409 and 412). In the Deferral Accounts Decision, the CRTC summarized its earlier findings that draw-downs could occur for various purposes, including through subscriber credits (at para. 6). When the CRTC approved the rates derived from the Price Caps Decision, the portion of the revenues that went into the deferral accounts remained encumbered. The deferral accounts, and the encumbrance to which the funds recorded in them were subject, were therefore an integral part of the rate-setting exercise ensuring that the rates approved were just and reasonable. It follows that nothing in the Deferral Accounts Decision changed either the Price Caps Decision or any other prior CRTC decision on this point. The CRTC's later allocation of deferral account balances for various purposes, therefore, including customer credits, was not a variation of a final rate order.

65 The allocation of deferral account funds to consumers was not, strictly speaking, a "rebate" in any event. Instead, as in *Bell Canada (1989)*, these allocations were one-time disbursements or rate reductions the carriers were required to make out of the deferral accounts to their *current* subscribers. The possibility of one-time credits was present from the inception of the rate-setting exercise. From the Price Caps Decision onwards, it was understood that the disposition of the deferral account funds might include an eventual credit to subscribers once the CRTC determined the appropriate allocation. It was precisely because the rate-setting mechanism approved by the CRTC included accumulation in and disposition from the deferral accounts pursuant to further CRTC orders, that the rates were and continued to be just and reasonable.

66 Therefore, rather than viewing *Bell Canada (1989)* as setting a strict rule that subscriber credits can never be ordered out of revenues derived from final rates, it is important to remember Gonthier J.'s concern that the financial stability of regulated utilities could be undermined if rates were open to indiscriminate variation (at p. 1760). Nothing in the Deferral Accounts Decision undermined the financial stability of the affected carriers. The amounts at issue were always treated differently for accounting purposes, and the regulated carriers were aware of the fact that the portion of their revenues going into the deferral accounts remained encumbered. In fact, the Price Caps Decision formula would have allowed for *lower* rates than the ones ultimately set, were it not for the creation of the deferral accounts. Those lower rates could conceivably have been considered sufficient to maintain the financial stability of the carriers and were increased only in an effort to encourage market entry by new competitors.

67 TELUS argued additionally that the Deferral Accounts Decision constituted a confiscation of its property. This is an argument I have difficulty accepting. The funds in the accounts never belonged unequivocally to the carriers, and always consisted of encumbered revenues. Had the CRTC intended that these revenues be used for any purposes the affected carriers wanted, it could simply have approved the rates as just and reasonable and ordered the balance of the deferral accounts turned over to them. It chose not to do so.

68 It is also worth noting that in approving Bell Canada's rates, the CRTC ordered it to allocate certain tax savings to the deferral accounts [10] . Neither the CRTC, nor Bell Canada, could possibly have expected that the company would be able to keep that portion of its rate revenue representing a past liability for taxes that it was in fact not currently liable to pay or defer.

69 For the above reasons, I would dismiss the Bell Canada and TELUS appeal.

70 The premise underlying the Consumers' Association of Canada appeal is that the disposition of some deferral account funds for broadband expansion highlighted the fact that the rates charged by carriers were, in a certain sense, not just and reasonable. Consumers can only succeed if it can demonstrate that the CRTC's decision was unreasonable.

71 At its core, Consumers' primary argument was that the Deferral Accounts Decision effectively forced users of a certain service (residential subscribers in certain areas) to subsidize users of another service (the future users of broadband services) once the expansion of broadband infrastructure was completed. In its view, this was an indication that the rates charged to residential users were not in fact just and reasonable, and that therefore the balance in the deferral accounts, excluding the disbursements for accessibility services, should be distributed to customers.

72 As previously noted, the deferral accounts were created and disbursed pursuant to the CRTC's power to approve just and reasonable rates, and were an integral part of such rates. Far from rendering these rates inappropriate, the deferral accounts *ensured* that the rates were just and reasonable. And the policy objectives in s. 7, which the CRTC is always obliged to consider, demonstrate that the CRTC need not limit itself to considering solely the service at issue in determining whether rates are just and reasonable. The statute contemplates a comprehensive national telecommunications framework. It does not require the CRTC to atomize individual services. It is for the CRTC to determine a tolerable level of cross-subsidization.

73 Nor does the traditional approach to telecommunications regulation support Consumers' argument. Long-distance telephone users have long subsidized local telephone users (Price Caps Decision, at para. 2). Therefore, while rates for individual services covered by the *Telecommunications Act* may be evaluated on a just and reasonable basis, rates are not necessarily rendered unreasonable or unjust simply because there is some cross-subsidization between services. (See Ryan, at §604, for the proposition that the CRTC can determine the appropriate extent of cross-subsidization for a given telecommunications carrier.)

74 In my view, the CRTC properly considered the objectives set out in s. 7 when it ordered expenditures for the expansion of broadband infrastructure and consumer credits. In doing so, it treated the statutory objectives as guiding

principles in the exercise of its rate-setting authority. Pursuing policy objectives through the exercise of its rate-setting power is precisely what s. 47 requires the CRTC to do in setting just and reasonable rates.

75 In deciding to allocate the deferral account funds to improving accessibility services and broadband expansion in rural and remote areas, the CRTC had in mind its statutorily mandated objectives of facilitating "the orderly development throughout Canada of a telecommunications system that serves to ... strengthen the social and economic fabric of Canada" under s. 7(*a*); rendering "reliable and affordable telecommunications services ... to Canadians in both urban and rural areas" under s. 7(*b*); and responding "to the economic and social requirements of users of telecommunications services" pursuant to s. 7(*h*).

76 The CRTC heard from several parties, considered its statutorily mandated objectives in exercising its powers, and decided on an appropriate course of action. Under the circumstances, I have no hesitation in holding that the CRTC made a reasonable decision in ordering broadband expansion.

77 I would therefore conclude that the CRTC did exactly what it was mandated to do under the *Telecommunications Act*. It had the statutory authority to set just and reasonable rates, to establish the deferral accounts, and to direct the disposition of the funds in those accounts. It was obliged to do so in accordance with the telecommunications policy objectives set out in the legislation and, as a result, to balance and consider a wide variety of objectives and interests. It did so in these appeals in a reasonable way, both in ordering subscriber credits and in approving the use of the funds for broadband expansion.

78 I would dismiss the appeals. At the request of all parties, there will be no order for costs.

Appeal dismissed.

Pourvoi rejeté.

Footnotes

1 *Telecom, Re* CRTC 2002-34 [2002 CarswellNat 5491 (C.R.T.C.)].

2 *Telecom, Re* CRTC 2005-69 [2005 CarswellNat 6973 (C.R.T.C.)].

3 *Telecom, Re* CRTC 2003-15 [2003 CarswellNat 6055 (C.R.T.C.)], and *Telecom Decision CRTC 2003-18* [2003 CarswellNat 6094 (C.R.T.C.)]

4 Telecom Public Notice CRTC 2004-1

5 *Telecom, Re* CRTC 2006-9 [2006 CarswellNat 6317 (C.R.T.C.)].

6 *Telecom, Re* CRTC 2008-1 [2008 CarswellNat 1061 (C.R.T.C.)].

7 *Telecom Decision CRTC 97-9* [1997 CarswellNat 3411 (C.R.T.C.)].

8 *Telecom Decision CRTC 94-19* [1994 CarswellNat 3191 (C.R.T.C.)].

9 *Telecom Decision CRTC 93-9* (July 23, 1993), Doc. 93-9 (C.R.T.C.).

10 Telecom Decision CRTC 2003-15, at para. 32.

Regulated Price Plan

Price Report

May 1, 2017

to

April 30, 2018

Ontario Energy Board

April 20, 2017

Executive Summary

This report contains the electricity commodity prices under the Regulated Price Plan (RPP) for the period May 1, 2017 through April 30, 2018. The prices were developed using the methodology described in the Regulated Price Plan Manual (RPP Manual).

In accordance with the applicable regulation, the OEB must forecast the cost of supplying RPP consumers and ensure that RPP prices reflect this cost. The OEB's practice is to review RPP prices every six months to determine if they need to be adjusted.

In broad terms, the methodology used to develop RPP prices has two essential steps:

1. Forecasting the total RPP supply cost for 12 months, and
2. Establishing prices to recover the forecast RPP supply cost from RPP consumers over the 12-month period.

The calculation of the total RPP electricity supply cost involves several separate forecasts, including:

- the hourly market price of electricity;
- the electricity consumption pattern of RPP consumers;
- the electricity supplied by those assets of Ontario Power Generation (OPG) whose price is regulated;
- the costs related to the contracts signed by non-utility generators (NUGs) with the former Ontario Hydro;
- the costs of the supply contracts, and conservation and demand management (CDM) initiatives of the Independent Electricity System Operator[1] (IESO); and
- the net variance account balance (as of April 30, 2017) carried by the IESO.

The market-based price for electricity used by RPP consumers reflects both the hourly market price of electricity and the electricity consumption pattern of RPP consumers. Residential consumers, who represent most RPP consumption, use relatively more of their electricity during times when total Ontario demand and prices are higher (than the overall Ontario average) and relatively less when total Ontario demand and prices are lower (than the overall Ontario average). This consumption pattern makes the average market price for RPP consumers higher than the average market price for the entire Ontario electricity market.

For this RPP price setting, the OEB has, consistent with its past practice of smoothing significant forecast price changes for customers, taken into account a portion of the estimated impact of the government's proposed Ontario Fair Hydro Plan announced on March 2, 2017. Legislation

[1] Contracts were formerly held by the Ontario Power Authority (OPA), which merged with the Independent Electricity System Operator effective January 1, 2015.

implementing the proposed Plan would, if passed, represent a significant step change in electricity bills for RPP consumers.

Average RPP Supply Cost

The hourly market price forecast was developed by Navigant Consulting Ltd. (Navigant). The forecast of the simple average market price for 12 months from May 1, 2017 is $22.81/MWh (2.281 cents per kWh). After accounting for the consumption pattern of RPP consumers, the average market price for electricity used by RPP consumers is forecast to be $24.83/MWh (2.483 cents per kWh).

The combined effect of the other components of the RPP supply cost is expected to increase this per kilowatt-hour price. The collective impact of the other components is summarized by the Global Adjustment. The Global Adjustment reflects the impact of the NUG contract costs, which are above market prices at most times, the regulated prices for OPG's prescribed nuclear and hydroelectric generating facilities (the prescribed assets), which may be above or below market prices, and any remaining cost of supply contracts held by the Independent Electricity System Operator (IESO) which generators have not recovered through their market revenues. The cost associated with Conservation and Demand Management (CDM) initiatives implemented by the IESO is also included. The forecast net impact of the Global Adjustment is to increase the average RPP supply cost by $87.67/MWh (8.767 cents per kWh).

Another factor to be taken into account is that actual prices and actual demand cannot be predicted with absolute certainty; both price and demand are subject to random effects. Two adjustments are made to account for this forecast variance. A small adjustment is made to the RPP supply cost to account for the fact that these random effects are more likely to increase than to decrease costs. This adjustment was determined to be $1.00/MWh (0.100 cents per kWh). Without this adjustment, the RPP would be expected to end the year with a small debit variance.

An additional adjustment factor is included in the RPP price to "clear" the expected balance in the IESO variance account as of April 30, 2017. The current balance accumulated in part as a result of keeping May 2016 prices in place for a full year. In addition, the variance is a result of typical factors such as weather variation, fluctuations in natural gas prices, and differences in other cost inputs. The forecast adjustment factor, which would be expected to clear the existing variance balance, is a debit (increase in the RPP price) of $1.40/MWh (0.140cents per kWh).

The resulting average RPP supply cost (for the period starting May 1, 2017) is $114.90/MWh. The average RPP price (RPA) is 11.49 cents per kWh, or 0.35 cents per kWh higher than the forecast for 12 months beginning May 2016.[2] This is summarized in Table ES-1.

[2] In November 2016, the OEB determined that the time-of-use and tiered prices would not change relative to May 2016 prices. The OEB determined that the May 2016 prices would continue to be effective in recovering forecast costs.

Table ES-1: Average RPP Supply Cost Summary

RPP Supply Cost Summary for the period from May 1, 2017 through April 30, 2018		
Forecast Wholesale Electricity Price		$22.81
Load-Weighted Price for RPP Consumers ($ / MWh)		$24.83
Impact of the Global Adjustment ($ / MWh)	+	$87.67
Adjustment to Address Bias Towards Unfavourable Variance ($ / MWh)	+	$1.00
Adjustment to Clear Existing Variance ($ / MWh)	+	$1.40
Average Supply Cost for RPP Consumers ($ / MWh)	=	**$114.90**

Source: Navigant

Inevitably, there will be a difference between the actual and forecast cost of supplying electricity to all RPP consumers. Differences can arise as a result of changes in demand due to weather, variation in natural gas prices, changes in the supply mix, as well as other factors. The sum of these differences is referred to as the unexpected variance, which in accordance with usual practice is taken into account in the next RPP period.

RPP prices are designed such that consumers pay a stable and predictable price that reflects the cost of supplying their electricity over time. These prices are always based on a forecast of the costs for the year ahead. A consideration that the OEB employs in all aspects of its rate-setting is to smooth significant price changes in order to support more gradual transitions in electricity costs for customers over time. With this consideration in mind, the OEB has historically included a portion of significant price changes that may occur in the forecast period because of the smoothing benefits for customers.

In keeping with this practice, the OEB has considered it appropriate in this price setting to take into account a portion of the estimated impact of the government's proposed Fair Hydro Plan. The OEB has done this by way of a reduction in the forecast amount of the Global Adjustment of approximately $1B, which represents 50% of RPP consumers' estimated portion of the proposed refinancing of the Global Adjustment. This yields a total estimated RPP supply cost of $5.8B, or an overall average RPP cost of $97.62/MWh or 9.76 cents per kWh, which is roughly 1.7 cents lower than the RPP supply cost absent any consideration of the estimated impact of the proposed Fair Hydro Plan. This translates to a reduction of about 15% on the electricity line, and about 17% on the electricity bill (including the impact of the 8% rebate provided for under the *Ontario Rebate for Electricity Consumers Act, 2016* and the OEB's decision to remove the Ontario Electricity Support Program charge) for a typical residential customer relative to what prices would otherwise have been, once RPP prices come into effect on May 1, 2017. This is summarized in Table ES-2.

The government has indicated that it intends to introduce legislation that would, if passed, implement the proposed Fair Hydro Plan starting this summer. The OEB will then further adjust RPP prices as needed so that RPP customers receive the full rate relief as legislated.

Table ES-2: Average RPP Supply Cost Summary with Consideration of the Proposed Fair Hydro Plan

RPP Supply Cost Summary for the period from May 1, 2017 through April 30, 2018		
Forecast Wholesale Electricity Price		$22.81
Load-Weighted Price for RPP Consumers ($ / MWh)		$24.83
Impact of the Global Adjustment ($ / MWh)	+	$70.39
Adjustment to Address Bias Towards Unfavourable Variance ($ / MWh)	+	$1.00
Adjustment to Clear Existing Variance ($ / MWh)	+	$1.40
Average Supply Cost for RPP Consumers ($ / MWh)	=	**$97.62**

Source: Navigant

Regulated Price Plan (TOU Pricing)

RPP consumers are not charged the average RPP supply cost. Rather, they pay prices under price structures that are designed to make their consumption weighted average price equal to the average supply cost. There are two RPP price structures, one for consumers with eligible time-of-use (or "smart") meters who pay time-of-use (TOU) prices, who make up the majority of RPP consumers, and one for consumers with conventional meters (Tiered Pricing).

Consumers with eligible time-of-use (or "smart") meters that can determine when electricity is consumed during the day will pay under a time-of-use price structure. The prices for this plan are based on three time-of-use periods per weekday[3]. These periods are referred to as Off-Peak (with a price of $RPEM_{OFF}$), Mid-Peak ($RPEM_{MID}$) and On-Peak ($RPEM_{ON}$).

The resulting TOU prices for consumers with eligible time-of-use meters would be the following, absent any consideration of the estimated impact of the proposed Fair Hydro Plan:

- $RPEM_{OFF}$ = 9.1 cents per kWh;
- $RPEM_{MID}$ = 13.3 cents per kWh; and,
- $RPEM_{ON}$ = 18.5 cents per kWh.

The resulting TOU prices for consumers with eligible time-of-use meters are the following after taking into account the reduction in the forecast amount of the Global Adjustment of approximately $1B:

- $RPEM_{OFF}$ = 7.7 cents per kWh;
- $RPEM_{MID}$ = 11.3 cents per kWh; and,
- $RPEM_{ON}$ = 15.7 cents per kWh.

[3] Weekends and statutory holidays have one TOU period: Off-peak.

These prices reflect the seasonal change in the TOU pricing periods which will take effect on May 1, 2017 and November 1, 2017. TOU pricing periods are:

- *Off-Peak* period (priced at $RPEM_{OFF}$):
  - *Winter and summer weekdays*: 7 p.m. to midnight and midnight to 7 a.m.
  - *Winter and summer weekends and holidays*:[4] 24 hours (all day)
- *Mid-Peak* period (priced at $RPEM_{MID}$)
  - *Winter weekdays (November 1 to April 30)*: 11 a.m. to 5 p.m.
  - *Summer weekdays (May 1 to October 31)*: 7 a.m. to 11 a.m. and 5 p.m. to 7 p.m.
- *On-Peak* period (priced at $RPEM_{ON}$)
  - *Winter weekdays*: 7 a.m. to 11 a.m. and 5 p.m. to 7p.m.
  - *Summer weekdays*: 11 a.m. to 5 p.m.

Regulated Price Plan - Tiered Pricing

RPP consumers that are not on TOU pricing pay prices in two tiers; one price (referred to as $RPCM_{T1}$) for monthly consumption up to a tier threshold and a higher price (referred to as $RPCM_{T2}$) for consumption over the threshold. The threshold for residential consumers changes twice a year on a seasonal basis: to 600 kWh per month during the summer season (May 1 to October 31) and to 1000 kWh per month during the winter season (November 1 to April 30). The threshold for non-residential RPP consumers remains constant at 750 kWh per month for the entire year.

The tiered prices for consumers with conventional meters would be the following, absent any consideration of the estimated impact of the proposed Fair Hydro Plan:

- $RPCM_{T1}$ = 10.7 cents per kWh, and
- $RPCM_{T2}$ = 12.5 cents per kWh.

The tiered prices for consumers with conventional meters are the following after taking into account the reduction in the forecast amount of the Global Adjustment of approximately $1B:

- $RPCM_{T1}$ = 9.1 cents per kWh, and
- $RPCM_{T2}$ = 10.6 cents per kWh.

Based on historical consumption, approximately 54% of RPP tiered consumption is forecast to be at the lower tier price ($RPCM_{T1}$) and 46% at the higher tier price ($RPCM_{T2}$). Given these

[4] For the purpose of RPP TOU pricing, a "holiday" means the following days: New Year's Day, Family Day, Good Friday, Christmas Day, Boxing Day, Victoria Day, Canada Day, Labour Day, Thanksgiving Day, and the Civic Holiday. When any holiday falls on a weekend (Saturday or Sunday), the next weekday following (that is not also a holiday) is to be treated as the holiday for RPP TOU pricing purposes.

proportions, the average price for conventional meter RPP consumption is forecast to be equal to the RPA.

The average price a consumer on TOU prices will pay depends on the consumer's load profile (i.e., how much electricity is used at what time). RPP prices are set so that a consumer with an *average* load profile will pay the same average price under either the tiered or TOU prices.

Major Factors Influencing RPP Prices

The forecast average supply cost for RPP consumers, absent any consideration of estimated impact of the proposed Fair Hydro Plan, increases by $3.49/MWh, or 3.1%, in the current forecast compared to the May 2016 forecast. A number of factors account for this change:

- Market prices are expected to be higher than in the previous price setting forecast period, primarily due to higher gas prices and despite slightly projected lower demand and higher availability of nuclear resources
- A decrease in the Ontario Electricity Financial Corporation contract and Ontario Power Generation payment amount components of the Global Adjustment are partially offset by increases in the IESO contract component of the Global Adjustment as a result of additional generation coming online

In summary, underlying cost factors- the load weighted market price for RPP consumers plus the Global Adjustment – increase the average supply cost by $3.05/MWh and the change in the variance account debit balance adds to the supply cost increase by $0.44/MWh. After taking into account the reduction in the forecast amount of the Global Adjustment of approximately $1B, the average supply cost drops by $13.79/MWh relative to May 2016 prices, or $17.28/MWh relative to what RPP consumers otherwise would have paid starting on May 1, 2017.

Regulated Price Plan – Prices Effective May 1, 2017

The RPP prices set by the OEB effective May 1, 2017 are set out in Table ES-3.

Table ES-3: May 1, 2017 RPP Prices

Time-of-Use RPP Prices	Off-Peak	Mid-Peak	On-Peak	Average Price
Price per kWh	7.7¢	11.3¢	15.7¢	9.8¢
% of TOU Consumption	65%	17%	18%	
Tiered RPP Prices	**Tier 1**		**Tier 2**	**Average Price**
Price per kWh	9.1¢		10.6¢	9.8¢
% of Tiered Consumption	53%		47%	

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1. Introduction

Under amendments to the *Ontario Energy Board Act, 1998* (the *Act*) contained in the *Electricity Restructuring Act, 2004*, the Ontario Energy Board (OEB) was mandated to develop a regulated price plan (RPP) for electricity prices to be charged to consumers that have been designated by legislation and that have not opted to switch to a retailer or to be charged the hourly spot market price. The first prices were implemented under the RPP effective on April 1, 2005, as set out by the Ontario Government in O. Reg. 95/05 (Classes of Consumers and Determination of Rates) made under the *Act*. This report covers the period from May 1, 2017 to April 30, 2018.

The OEB has issued a Regulated Price Plan Manual (RPP Manual[5]) that explains how RPP prices are set. The OEB relies on a forecast of wholesale electricity market prices, prepared by Navigant as a basic input into the forecast of RPP supply costs as per the RPP Manual methodology.

This Report describes how the OEB has used the RPP Manual's processes and methodologies to arrive at the RPP prices effective May 1, 2017.

This Report consists of four chapters as follows:

- Chapter 1. Introduction
- Chapter 2. Calculating the RPP Supply Cost
- Chapter 3. Calculating RPP Prices
- Chapter 4. Expected Variance

1.1 Associated Documents

Two documents are closely associated with this Report:

- The *Regulated Price Plan Manual* (RPP Manual) describes the methodology for setting RPP prices; and,
- The *Ontario Wholesale Electricity Market Price Forecast For the Period May 1, 2017 through October 31, 2018* (Market Price Forecast Report),[6] prepared by Navigant, contains the Ontario wholesale electricity market price forecast and explains the material assumptions which lie behind the hourly price forecast. Those assumptions are not repeated in this Report.

1.2 Process for RPP Price Determinations

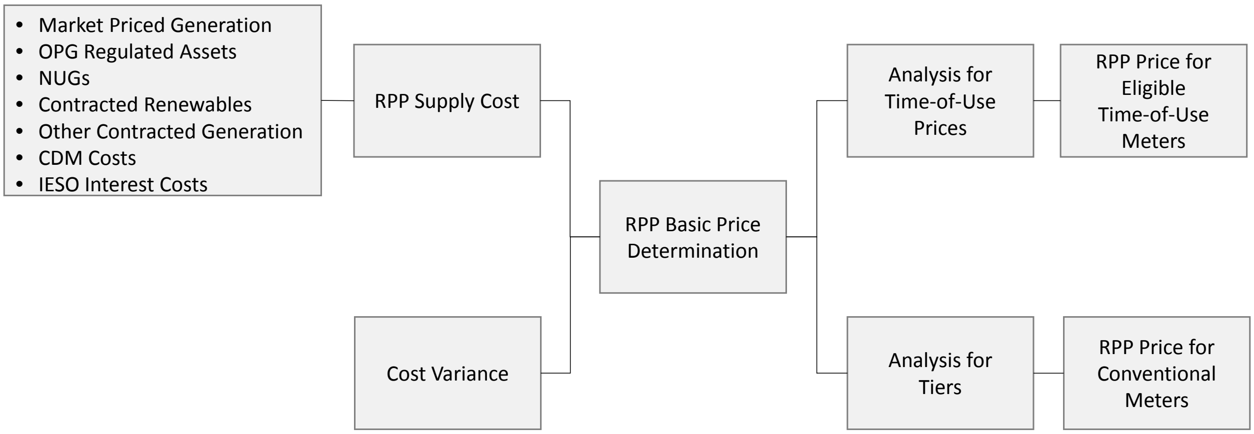
Figure 1 below illustrates the process for setting RPP prices. The RPP supply cost and the accumulated variance account balance (carried by the Independent Electricity System Operator, or the IESO) both contribute to the base RPP price, which is set to recover the electricity supply cost. The diagram below illustrates the processes to be followed to set the RPP price for both

[5] http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2004-0205/RPP_Manual.pdf

[6] The Market Price Forecast Report is posted on the OEB web site, along with the RPP Price Report, on the RPP web page. http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2004-0205/Wholesale_Price_Forecast_Report_May2017.pdf

consumers with conventional meters and those with eligible time-of-use meters (or "smart" meters).

Figure 1: Process Flow for Determining the RPP Price



Source: RPP Manual

This Report is organized according to this basic process.

2. Calculating the RPP Supply Cost

The RPP supply cost calculation formula is set out in Equation 1 below. To calculate the RPP supply cost requires forecast data for the terms in Equation 1. Most of the terms depend on more than one underlying data source or assumption. This chapter describes the data or assumption source for each of the terms and explains how the data were used to calculate the RPP supply cost. More detail on this methodology is in the RPP Manual.

It is important to remember that the elements of Equation 1 are forecasts. In some cases, the calculation uses actual historical values, but in these cases the historical values constitute the best available forecast.

2.1 Defining the RPP Supply Cost

Equation 1 below defines the RPP supply cost. This equation is further explained in the RPP Manual.

Equation 1

$$C_{RPP} = M + \alpha\,[(A - B) + (C - D) + (E - F) + G] + H, \text{ where}$$

- C_{RPP} is the total RPP supply cost;
- M is the amount that the RPP supply would have cost under the Market Rules;
- α is the RPP proportion of the total Global Adjustment costs;[7]
- A is the amount paid to prescribed generators in respect of the output of their prescribed generation facilities;[8]
- B is the amount those generators would have received under the Market Rules;
- C is the amount paid to the Ontario Electricity Finance Corporation (OEFC) with respect to its payments under contracts with non-utility generators (NUGs);
- D is the amount that would have been received under the Market Rules for electricity and ancillary services supplied by those NUGs;
- E is the amount paid to the IESO with respect to its payments under certain contracts with renewable generators;

[7] The elements in square brackets collectively represent the Global Adjustment. For RPP price setting purposes the elements of the Global Adjustment are described differently in this Report than they are in O. Reg. 429/04 (Adjustments under Section 25.33 of the Act) made under the *Electricity Act, 1998.* "G" in the expression in square brackets integrates two separate components of the Global Adjustment formula (G and H). "E" and "F" in the expression in square brackets include certain generation contracts that are associated with "G" in O. Reg. 429/04. This is necessary to ensure that there is no double-counting and thus over-recovery of generation costs because all RPP supply is included in "M". As discussed below, forecast Global Adjustment costs are recovered through the RPP according to the allocation of the Global Adjustment between Class A and Class B consumers, and the RPP consumers' share of Class B consumption.

[8] As set out in regulation O. Reg. 53/05 (Payments under Section 78.1 of the Act) made under the *Act*, the OEB sets payment amounts for energy produced from Ontario Power Generation's nuclear and certain hydro-electric generating stations (the prescribed assets). The OEB's most recent Order setting base payment amounts (EB-2013-0321) was issued on December 18, 2014.

- F is the amount that would have been received under the Market Rules for electricity and ancillary services supplied by those renewable generators;
- G is (a) the amount paid by the IESO for its other procurement contracts for generation or for demand response or CDM, and (b) the sum of any OEB-approved amounts for CDM programs that are payable by the IESO to distributors; and,
- H is the amount associated with the variance account held by the IESO. This includes any existing variance account balance needed to be recovered (or disbursed) in addition to any interest incurred (or earned).

The forecast per unit RPP supply cost will be the total RPP supply cost (C_{RPP}) divided by the total forecast RPP demand. RPP prices will be based on that forecast per unit cost.

2.2 Computation of the RPP Supply Cost

Broadly speaking, the steps involved in forecasting the RPP supply cost are:

1. Forecast wholesale market prices;
2. Forecast the load shape for RPP consumers;
3. Forecast the quantities in Equation 1; and
4. Forecast RPP Supply Cost = Total of Equation 1.

In addition to the four steps listed above, the calculation of the total RPP supply cost requires a forecast of the stochastic adjustment, which is not included in Equation 1. The stochastic adjustment is included in the RPP Manual as an additional cost factor calculated outside of Equation 1. Since the RPP prices are always announced by the OEB in advance of the actual price adjustment being implemented, it is also necessary to forecast the net variance account balance at the end of the current RPP period (April 30, 2017).[9] This amount is included in Equation 1 ("H").

In May 2016, the *Climate Change Mitigation and Low-carbon Economy Act, 2016* received Royal Assent and Ontario Regulation 144/16 was issued. Together, the legislation and regulation provide details about the Cap and Trade Program, which began on January 1, 2017. Under the legislation, large final emitters, natural gas distributors and electricity importers are required to verify and report their greenhouse gas emissions to the provincial government, and have to match their total emissions in each compliance period with an equivalent amount of "allowances."

Accordingly, this RPP forecast accounts for the cap and trade program over all twelve months of the RPP period. As more fully detailed in the Market Price Forecast Report, the forecast of wholesale market prices reflects the forecast of gas prices using a carbon price of $18.07 per metric ton, consistent with the results report of Ontario's first cap and trade auction (*March 2017 Ontario Auction #1)*, and an emissions factor of 0.054 metric tons per MMBtu.

[9] RPP prices are announced in advance by the OEB to provide notification to consumers of the upcoming price change and to provide distributors with the necessary amount of time to incorporate the new RPP prices into their billing systems.

The following sections will describe each term or group of terms in Equation 1, the data used for forecasting them, and the computational methodology to produce each component of the RPP supply cost.

2.2.1 Forecast Cost of Supply Under Market Rules

This section covers the first term of Equation 1:

$$C_{RPP} = \boldsymbol{M} + \alpha\ [(A - B) + (C - D) + (E - F) + G] + H.$$

The forecast cost of supply to RPP consumers under the Market Rules depends on two forecasts:

- The forecast of the simple average hourly Ontario electricity price (HOEP) in the IESO-administered market over all hours in each month of the year; and
- The forecast of the ratio of the load-weighted average market price paid by RPP consumers in each month to the simple average HOEP in that month.

The forecast of HOEP is taken directly from the Market Price Forecast Report. That Report also contains a detailed explanation of the assumptions that underpin the forecast such as generator fuel prices (e.g., natural gas). Table 1 below shows forecast seasonal on-peak, off-peak, and average prices. The prices provided in Table 1 are simple averages over all of the hours in the specified period (i.e., they are not load-weighted). These on-peak and off-peak periods differ from and should not be confused with the TOU periods associated with the RPP TOU prices discussed later in this report.

Table 1: Ontario Electricity Market Price Forecast ($ per MWh)

Term	Quarter	Calendar Period	On-Peak	Off-Peak	Average	Term Average
RPP Year	Q1	May 17 - Jul 17	$26.49	$11.55	$18.45	
	Q2	Aug 17 - Oct 17	$31.30	$16.57	$23.26	
	Q3	Nov 17 - Jan 18	$34.57	$20.47	$26.89	
	Q4	Feb 18 - Apr 18	$29.32	$16.95	$22.63	$22.81
Other	Q1	May 18 - Jul 18	$26.76	$13.01	$19.36	
	Q2	Aug 18 - Oct 18	$26.27	$13.05	$19.06	$19.21

Source: Navigant, *Wholesale Electricity Market Price Forecast* report
Note: On-peak hours include the hours ending at 8 a.m. through 11 p.m. Eastern Standard Time (EST) on working weekdays and off-peak hours include all other hours. The definition of "on-peak" and "off-peak" hours for this purpose bears no relation to the "on-peak", "mid-peak" and "off-peak" periods used for RPP TOU pricing.

The forecasts of the monthly ratios of load-weighted vs. simple average HOEP are based on actual prices between April 2005 and March 2017. The on-peak to off-peak ratio is also based on data through March 2017.

As shown in Table 1, the forecast simple average HOEP for the period May 1, 2017 to April 30, 2018 is $22.81/MWh (2.281 cents per kWh). The forecast of the load weighted average price for RPP consumers ("M" in Equation 1) is $24.83/MWh (2.483 cents per kWh), or $1.5 billion in total, the result of RPP consumers having load patterns that are more peak oriented than the overall system.

2.2.2 RPP Share of the Global Adjustment

Alpha ("α") in Equation 1 represents the share of the Global Adjustment paid by (or credited to) RPP consumers. Effective January 1, 2011, O. Reg. 429/04 (Adjustments under Section 25.33 of the *Act*) made under the *Electricity Act, 1998* was amended to revise how Global Adjustment costs are allocated to two sets of consumers, Class A and Class B (includes RPP consumers)[10].

The first step to determine alpha is to estimate Class A's share of the Global Adjustment. Based on the formula and periods defined in O. Reg. 429/04, the Class A share has been decreased to 11.7% for the July 2016 to June 2017 period; and it is assumed for the purposes of this forecast to remain at that level for the July 2017 to June 2018 period.[11] Class B's share of the Global Adjustment is therefore 88.3%.

The next step is to estimate RPP consumers' share of Class B consumption. Based on historical data on RPP consumption as a share of total Ontario consumption, it is forecast that RPP consumption will represent about 60 TWh or 53.1% of total Class B consumption.[12] The RPP share varies from month to month, ranging between 51.3% and 55.8%. The value of α therefore ranges between 0.453 and 0.493. Over the entire RPP period, RPP consumers are forecast to be responsible for 47.1% of the Global Adjustment.

The government has recently expanded the Industrial Conservation Initiative to include, on an opt-in basis, all electricity loads with an average monthly peak demand over 1MW and certain electricity loads with an average monthly peak demand over 500 kW. This RPP price setting does not reflect any adjustments to account for the impact of these changes owing to the fact that uptake for the program by these newly-eligible consumers is not currently known, and the OEB does not have the information necessary to forecast that uptake.

2.2.3 Cost Adjustment Term for Prescribed Generators

This section covers the second term of Equation 1:

$$C_{RPP} = M + \alpha\ [\boldsymbol{(A - B)} + (C - D) + (E - F) + G] + H$$

The prescribed generators are comprised of the rate-regulated nuclear and hydroelectric facilities of Ontario Power Generation (OPG). The amounts paid for the prescribed generation as set out in the EB-2013-0321 Payment Amounts Order dated December 18, 2014 is \$59.29/MWh for nuclear generation, \$40.20/MWh for prescribed hydroelectric generation and \$41.93/MWh for prescribed hydroelectric generation.

On May 27, 2016, OPG filed an application (EB-2016-0152) seeking approval for payment amounts for its prescribed generation facilities commencing January 1, 2017 through to the end

[10] O. Reg. 429/04 defines two classes of consumers; Class A, comprised of consumers whose maximum hourly demand for electricity exceeds a specified threshold; and Class B consumers, comprised of all other consumers, including RPP consumers. The demand threshold for Class A eligibility has been reduced over time, most recently by amendments to O. Reg. 429/04 made in 2016 (O. Reg. 366/16) and 2017 (O. Reg. 107/17).

[11] The percentage of Class A Global Adjustment costs was based on Class A load during peak demand hours in the May 1, 2015 to April 30, 2016 period. The Class A peak demand factor effective for the July 1, 2016 to June 30, 2017 period will be based on peak load percentages in the May 1, 2015 to April 30, 2016 period.

[12] The Class A/Class B split did not exist before January 2011. Data on RPP consumption as a share of total Class B consumption is available only for the January 2011 to March 2017 period.

of 2021. On March 8, 2017, OPG submitted an amended rate smoothing proposal with updated payment amounts. At the time this report was prepared, a final decision and order with respect to OPG payment amounts was not available.

Consistent with past practice, the OEB believes that it is appropriate to take into account some effect of the application in this RPP forecast. This approach is consistent with one of the objectives of the RPP, which is to smooth changes in prices over time. Therefore, 50% of the impact of OPG's requested payment amounts, as smoothed by OPG's updated smoothing proposal, has been used for the purpose of calculating the RPP prices. The inclusion of an amount in the RPP should in no way be taken as predictive of the outcome of the OEB's proceeding.

Quantity A was therefore forecast by multiplying payment amounts per MWh consistent with the assumption described above, by the prescribed assets' total forecast output per month in MWh.

Quantity B was forecast by estimating the market values of each MWh of nuclear and prescribed hydraulic generation, and multiplying those market values by the volume of nuclear and prescribed hydraulic generation. The value of A is \$4.2 billion, and the value of B is \$1.6 billion.

2.2.4 Cost Adjustment Term for Non-Utility Generators and Other Generation under Contract with the OEFC

This section describes the calculation of the third term of Equation 1:

$$C_{RPP} = M + \alpha\,[(A - B) + \boldsymbol{(C - D)} + (E - F) + G] + H$$

Although the details of these payments (amounts by recipient, volumes, etc.) are not public, published information from the IESO about aggregate monthly payments to non-utility generators (NUGs) has been used as the basis for forecasting payments in future months. This data has been supplemented by information provided by the OEFC. This forecast was used to compute an estimate of the total payments to the NUGs under their contracts, or amount C in Equation 1.

The amount that the NUGs would receive under the Market Rules, quantity D in Equation 1, is their hourly production times the hourly Ontario energy price. These quantities were forecast on a monthly basis, as an aggregate for the NUGs as a whole.

The value of "C" in Equation 1 (i.e., the contract cost of the NUGs) is estimated to be \$0.4 billion, and the value of "D" (i.e., the market value of the NUG output) is estimated to be \$0.1 billion.

2.2.5 Cost Adjustment Term for Certain Renewable Generation Under Contract with the IESO

This section describes the calculation of the fourth term of Equation 1:

$$C_{RPP} = M + \alpha\,[(A - B) + (C - D) + \boldsymbol{(E - F)} + G] + H$$

Quantities E and F in the above formula refer to certain renewable generators paid by the IESO under contracts related to output. Generators in this category are renewable generators under the following contracts:

- Renewable Energy Supply (RES) Request for Proposals (RFP) Phases I, II and III;
- the Renewable Energy Standard Offer Program (RESOP);
- the Feed-In Tariff (FIT) Program;
- the Hydroelectric Energy Supply Agreements (HESA) directive, covering new and redeveloped hydro facilities; and,
- the Hydro Contract Initiative (HCI), covering existing hydro plants.

Quantity E in Equation 1 is the forecast quantity of electricity supplied by these renewable generators times the fixed price they are paid under their contract with the IESO. The statistical model includes estimates of the fixed prices. In some cases, this is simply the announced contract price (e.g., $420/MWh for solar generation under RESOP). In others, the contract price needs to be adjusted in each year either partially or fully in proportion to inflation. In still others, detailed information on contract prices is not available, and they have been estimated based on publicly-available information (for example, the Ontario Government announced that the weighted average price for Renewable RFP I projects was $79.97/MWh, but did not announce prices for individual contracts).[13]

The size and generation type of the successful renewable energy projects to date have been announced by the Government and the IESO. The statistical model produced forecasts of additional renewable capacity coming into service during the RPP period, and the monthly output of both existing and new plants, using either historical values of actual outputs (where available), or estimates based on the plants' capacities and estimated capacity factors. The statistical model also forecasts average market revenues for each plant or type of plant. Quantity F in Equation 1 is therefore the forecast output of the renewable generation multiplied by the forecast average market revenue (based on market prices in the Wholesale Market Price Forecast Report) at the time that output is generated.

The value of "E" in Equation 1 (i.e., the contract cost of renewable generation) is estimated to be $4.7 billion, and the value of "F" (i.e., the market value of renewable generation) is estimated to be $0.5 billion.

2.2.6 Cost Adjustment Term for Other Contracts with the IESO

This section describes the calculation of the fifth term of Equation 1:

$$C_{RPP} = M + \alpha\,[(A - B) + (C - D) + (E - F) + \boldsymbol{G}] + H$$

[13] For information related to the FIT Price Schedule, see the IESO's dedicated web page at: http://www.ieso.ca/sector-participants/feed-in-tariff-program/overview

The costs for three types of resources under contract with the IESO are included in G:

1. conventional generation (e.g., natural gas) whose payment relates to the generator's capacity costs;
2. demand side management or demand response contracts; and
3. Bruce Power, which has an output-based contract for generation from its Bruce A and B nuclear facilities.

The contribution of conventional generation under contract to the IESO to quantity G relates to several contracts:

- Clean Energy Supply (CES) and other contracts, which include conventional generation contracts as well as one demand response contract awarded to Loblaws;[14]
- The "early mover" contracts; and
- Contracts awarded for projects classified as Combined Heat and Power (CHP) projects[15].

The costs of these contracts, for the purpose of calculating the RPP supply cost, are based on an estimate of the contingent support payments to be paid under the contract guidelines. The contingent support payment is the difference between the net revenue requirement (NRR) stipulated in the contracts and the "deemed" energy market revenues. The deemed energy market revenues were estimated based on the deemed dispatch logic as stipulated in the contract and the Market Price Forecast Report that underpins this RPP price setting activity. The NRRs and other contract parameters for each contract have been estimated based on publicly available information. Examples include the average NRR for the CES contracts which was announced by the Government to be $7,900 per megawatt-month,[16]as well as an NRR of $17,000 per megawatt-month for the cancelled Oakville Generating station which has been used as a guideline for some of the more recent gas plant additions.

The cost to the IESO of any additional CDM initiatives is also captured in term G of Equation 1. Starting on January 1, 2015, and continuing until December 31, 2020, electricity distributors are expected to continue to offer CDM programs to customers in their service area, consistent with the Minister of Energy's Directive issued to the OEB and the Direction to the OPA, both dated March 31, 2014. Costs for these programs will be recovered and settled with the IESO, by way of contracts with the LDCs, for the period 2015 to 2020.

[14] Ten facilities holding CES and other contracts are operational during this RPP period: the GTAA Cogeneration Facility, the Loblaws Demand Response Program, eight large gas-fired plants (Portlands, Goreway, Greenfield, St. Clair, York Energy Centre, Halton Hills, Green Electron Power, and Napanee), and two biomass projects (Atikokan and Thunder Bay). The IESO entered into contracts with these facilities pursuant to directives from the Minister of Energy.

[15] Seven facilities holding CHP Phase I contracts are expected to be operational during this RPP period: the Great Northern Tri-gen Facility, the Durham College District Energy Project, the Countryside London Cogeneration Facility, the Warden Energy Centre, the Algoma Energy Cogeneration Facility, the East Windsor Cogeneration Centre, and the Thorold Cogeneration Project. Other facilities from other procurement processes are included as well.

[16] The NRR for the "early movers" was assumed to be the same.

In December 2015, the IESO negotiated an amended agreement with Bruce Power in relation to the refurbishment and continued operation of the Bruce Power nuclear units[17]. The amended contract stipulates that an initial price of $65.73/MWh would be paid for the output of Bruce A and B. The amended contract also stipulates that the initial price will be indexed to inflation every April 1, as well as adjusted periodically for asset management, waste fees, and refurbishments. For the upcoming RPP period, these revised contract terms have been applied for the output of Bruce A and B.

The IESO has a contract with OPG for the on-going operation of OPG's Lennox Generating Station, a 2,140-MW peaking plant. The cost of this contract is included in the "G" variable.

The value of "G" in Equation 1 (i.e., net cost of Bruce nuclear, gas and Lennox generation plus CDM programs) is estimated to be $4.1 billion.

2.2.7 Estimate of the Global Adjustment

The total Global Adjustment is estimated to be a cost of $11.1 billion. The RPP share of this (i.e., α times the total cost) is estimated to be a cost of $5.2 billion, or $87.67/MWh (8.767 cents per kWh). This is the forecast of the average Global Adjustment cost per unit that will accrue to RPP consumers over the period from May 1, 2017 to April 30, 2018.

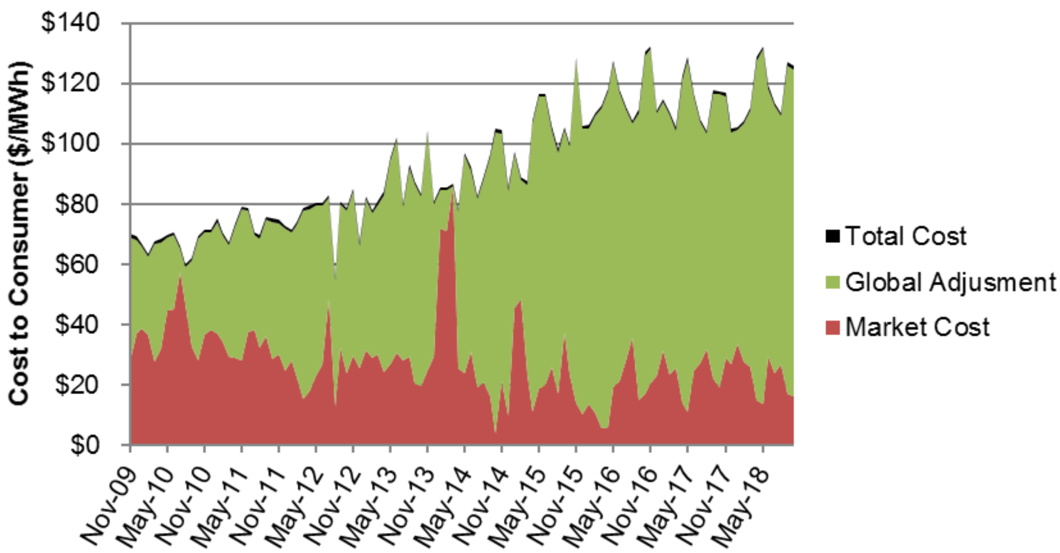
The Global Adjustment represents the difference between the total contract cost of the various contracts it covers (for the prescribed generating assets, Bruce nuclear, gas plants, renewable generation, CDM, etc.) and the market value of contracted generation. The Global Adjustment therefore changes for two reasons:

- changes (usually increases) in the number and aggregate capacity of contracts it covers, or
- fluctuations in the market revenues earned by contracted and prescribed generation.

This is illustrated in Figure 2, which shows how the Global Adjustment is expected to change over the next 18 months. All Ontario consumers have been paying the full cost of the contracts covered by the Global Adjustment, either through market costs or through the Global Adjustment itself. The Global Adjustment fluctuates as market prices rise and fall, but the total supply cost (market cost plus Global Adjustment) is expected to slightly increase over the next 12 months.

[17] In 2005, Bruce Power entered into an initial Bruce Power Refurbishment Implementation Agreement in relation to the operation of Bruce Units 1 and 2. In December 2015, the IESO and Bruce Power entered into an Amended and Restated Bruce Power Refurbishment Implementation Agreement.

Figure 2: Components of the RPP Supply Cost



Source: Navigant

Overall, supply costs have increased by 3.1% between this RPP period and the supply costs which were applicable to the May 2016 price setting and then maintained for the November 2016 price setting. For the first time in several forecasts, temporary payments to recover costs of prescribed generation assets, which expired at the end of 2016, no longer feature in the 12 month forecast. Underlying costs are lower as a result. However, that decrease is largely offset by an increase in costs related primarily to new renewable sources of generation. Similarly, higher wholesale market prices result in only a slight increase in supply cost because they are largely offset by a decrease in the Global Adjustment.

2.2.8 Cost Adjustment Term for IESO Variance Account

This section describes the calculation of the sixth term of Equation 1:

$$C_{RPP} = M + \alpha\ [(A - B) + (C - D) + (E - F) + G] + \boldsymbol{H}$$

The cost adjustment term for the IESO variance account consists of two factors. The first is the forecast interest costs associated with carrying any RPP-related variances incurred during the upcoming RPP period (May 2017 – April 2018). The second represents the price adjustment required to clear (i.e., recover or disburse) the existing RPP variance and interest accumulated over the previous RPP period.

The first term discussed above is small, as any interest expenses incurred by the IESO to carry consumer debit variances in some months are generally offset by interest income the IESO receives from carrying consumer credit balances in other months. In addition, the interest rate paid by the IESO on the variance account is relatively low.

The second term is significant. It represents the price adjustment necessary to clear the total net variance accumulated since the RPP was introduced on April 1, 2005 through to the beginning of this RPP Period. As of April 30, 2017 the net variance account balance is forecast to be a negative balance (i.e. a deficit) of approximately $84 million including interest. This is quantity "H" in Equation 1.

A variance clearance factor has been calculated that is estimated to bring the variance account to approximately a zero balance over the twelve-month period, after taking into account both the changes in total RPP consumption and the Final RPP Variance Settlement Amount payments expected as of April 30, 2017. This variance clearance factor has increased from a debit of 0.097 cents per kWh in the May 2016 RPP report to a debit of 0.140 cents per kWh, based on costs and market activity from April 2016 through to April 2017. This increase in the variance account balance is due in part to May 2016 prices being continued in November 2016. Despite slightly higher forecast supply costs in November 2016 relative to May 2016, it was determined that the May 2016 RPP prices would continue to be effective in recovering the forecast costs attributable to customers on the Regulated Price Plan and no adjustments to prices were made in November 2016. In addition, the variance is a result of typical factors such as weather variation, fluctuations in natural gas prices, and differences in other cost inputs. As a result, the debit that had accumulated in the variance account was further increased. The variance clearance factor increases the average RPP supply cost by the amount of the debit: $1.40/MWh (0.140 cents per kWh).

2.3 Correcting for the Bias Towards Unfavorable Variances

The supply costs discussed in section 2.2 are based on a forecast of the HOEP. However, actual prices and actual demand cannot be predicted with absolute certainty. Calculating the total RPP supply cost therefore needs to take into account the fact that volatility exists amongst the forecast parameters, and that there is a slightly greater likelihood of negative or unfavourable variances than favourable variances. For example, because nuclear generation plants tend to operate at capacity factors between 80% and 90%, these facilities are more likely to supply less energy than forecast (due to unscheduled outages) than to supply more than forecast (i.e., there is 10-20% upside versus 80-90% downside on the generator output). Similarly, during unexpectedly cold or hot weather, prices tend to be higher than expected as does RPP consumers' demand for electricity. The net result is that the RPP would be "expected" to end the year with a small unfavourable variance in the absence of a minor adjustment to reflect the greater likelihood of unfavourable variances.

The OEB regularly reviews the differences between the estimated and actual RPP supply cost. Based on this experience, the Adjustment to Address Bias Towards Unfavourable Variance is set at $1.00/MWh (0.100 cents per kWh). This amount is included in the price paid by RPP consumers to ensure that the "expected" variance at the end of the RPP year is zero.

2.4 Total RPP Supply Cost

Table 2 shows the percentage of Ontario's total electricity supply attributable to various generation sources, the percentage of forecasted Global Adjustment costs for each type of generation and the total unit costs. Total unit costs are based on contracted costs for each generation type, including global adjustment payments and market price payments, where applicable.

Table 2: Total Electricity Supply Cost

	% of Total Supply	% of Total GA	Total Unit Cost (Cents/kWh)
Nuclear	60%	40%	6.9
Hydro	24%	12%	5.8
Gas	6%	15%	20.5
Wind	8%	18%	17.3
Solar	2%	14%	48.0
Bio Energy	0%	0%	13.1

Source: Navigant

NB: Hydro excludes NUGs and OPG non-prescribed generation. Gas includes Lennox, NUGs and OPG bioenergy facilities. Percentage (%) of Total GA excludes CDM costs.

The total RPP supply cost is estimated to be $6.9 billion.[18]

The following table itemizes the various steps discussed above to arrive at an average RPP supply cost of $114.90/MWh. This average supply cost corresponds to an average RPP price, which is referred to as RPA, of 11.49 cents per kWh.

Table 3: Average RPP Supply Cost Summary

RPP Supply Cost Summary for the period from May 1, 2017 through April 30, 2018		
Forecast Wholesale Electricity Price		$22.81
Load-Weighted Price for RPP Consumers ($ / MWh)		$24.83
Impact of the Global Adjustment ($ / MWh)	+	$87.67
Adjustment to Address Bias Towards Unfavourable Variance ($ / MWh)	+	$1.00
Adjustment to Clear Existing Variance ($ / MWh)	+	$1.40
Average Supply Cost for RPP Consumers ($ / MWh)	=	**$114.90**

Source: Navigant

RPP prices are designed such that consumers pay a stable and predictable price that reflects the cost of supplying their electricity over time. These prices are always based on a forecast of the costs for the year ahead. A consideration that the OEB employs in all aspects of its rate-setting is to smooth significant price changes in order to support more gradual transitions in electricity costs for customers over time. With this consideration in mind, the OEB has historically included a portion of significant price changes that may occur in the forecast period because of the smoothing benefits for customers. The OEB has done this with respect to payments for OPG's generation output when an application is before the OEB but has not yet been adjudicated to a final decision. As noted above, the OEB is doing the same in this price-setting.

In keeping with this practice, the OEB has considered it appropriate in this price setting to take into account a portion of the estimated impact of the government's proposed Fair Hydro Plan. The government has stated that it proposes to take steps to lower electricity bills starting this summer, and that it intends to introduce legislation to implement the proposed Plan. Legislation implementing the proposed Fair Hydro Plan would, if passed, represent a

[18] The total cost figure is net of the forecast variance account balance as of April 30, 2017.

significant step change in electricity bills for RPP consumers during the forecast period associated with this RPP price setting.

In a letter to the OEB dated April 10, 2017, a copy of which is attached to this Report, the Minister of Energy provided additional detail regarding elements of the proposed Fair Hydro Plan for consideration as inputs into this RPP price setting as the OEB considers appropriate. Taking into consideration that additional detail as well as information made available to the public by the government when it announced the proposed Fair Hydro Plan on March 2, 2017, the OEB has reflected a portion of the estimated impact of the proposed Fair Hydro Plan by way of a reduction in the forecast amount of the Global Adjustment of approximately $1B or about $17.28/MWh. Based on an estimate of consumption provided to the OEB by letter from Ministry staff, a copy of which is attached to this Report, this reduction in the forecast Global Adjustment represents 50% of RPP consumers' estimated portion of the proposed refinancing of the Global Adjustment.[19] No provision has been made for changes in consumption patterns that may result from the proposed Fair Hydro Plan.

This yields a total estimated RPP supply cost of $5.8B, or an overall average RPP cost of $97.62/MWh or 9.76 cents per kWh, which is roughly 1.7 cents lower than the RPP supply cost absent any consideration of the estimated impact of the proposed Fair Hydro Plan. This translates to a reduction of about 15% on the electricity line, and about 17% on the total electricity bill (including the impact of the 8% rebate provided for under the *Ontario Rebate for Electricity Consumers Act, 2016* and the OEB's decision to remove the Ontario Electricity Support Program charge) for a typical residential customer relative to what prices would otherwise have been, once RPP prices come into effect on May 1, 2017. This is summarized in Table 4.

Table 4: Average RPP Supply Cost Summary with Consideration of the Proposed Fair Hydro Plan

RPP Supply Cost Summary for the period from May 1, 2017 through April 30, 2018		
Forecast Wholesale Electricity Price		$22.81
Load-Weighted Price for RPP Consumers ($ / MWh)		$24.83
Impact of the Global Adjustment ($ / MWh)	+	$70.39
Adjustment to Address Bias Towards Unfavourable Variance ($ / MWh)	+	$1.00
Adjustment to Clear Existing Variance ($ / MWh)	+	$1.40
Average Supply Cost for RPP Consumers ($ / MWh)	=	**$97.62**

Source: Navigant

Taking the estimated impact of the proposed Fair Hydro Plan into account in setting May 1, 2017 RPP prices protects the interests of consumers. Reflecting only a portion of that estimated impact in prices at this time and under present circumstances is in keeping with the OEB's

[19] As indicated in the Minister's letter, the government's proposal to take steps to lower electricity bills relative to what they would otherwise have been without the Fair Hydro Plan is expected to benefit consumers beyond those that are on the RPP. The Ministry provided the OEB with an estimate of consumption for all RPP-eligible consumers, whether they are actually on the RPP or have opted out of it (about 72 TWh annually). As noted in section 2.2.2, the OEB estimates that RPP consumers will consume roughly 60 TWh over the coming 12 months.

normal RPP forecasting activities. The government has indicated that it intends to introduce legislation that would, if passed, implement the proposed Fair Hydro Plan starting this summer. The OEB will then further adjust RPP prices as needed so that RPP customers receive the full rate relief as legislated. As set out in section 3 of the RPP Manual (Price True-Ups for Extraordinary Circumstances), a mechanism also already exists to accommodate and remedy material and unexpected departures from the forecast that impair the effectiveness of RPP prices.

3. Calculating the RPP Price

The previous chapter calculated a forecast of the total RPP supply cost. Given the forecast of total RPP demand, it also produced a computation of the average RPP supply cost and the average RPP supply price, RPA. This chapter explains how prices are determined for consumers with eligible time-of-use meters that are being charged the TOU prices, $RPEM_{ON}$, $RPEM_{MID}$, and $RPEM_{OFF}$, and for the tiers, $RPCM_{T1}$ and $RPCM_{T2}$.

3.1 Setting the TOU Prices for Consumers with Eligible Time-of-Use Meters

For those consumers with eligible time-of-use meters, three separate prices apply. The times when these prices apply varies by time of day and season, as set out in the RPP Manual. There are three price levels: On-peak ($RPEM_{ON}$), Mid-peak ($RPEM_{MID}$), and Off-peak ($RPEM_{OFF}$). The load-weighted average price must be equal to the RPA.

As described in the RPP Manual, the three prices are calculated to recover the supply cost, given the load shape of TOU customers. The RPP Manual does not prescribe the order in which prices are determined.

The first step in deriving the TOU prices for this forecast period was to set the Off-peak price, or $RPEM_{OFF}$. This price reflects the forecast market price during that period, including the Global Adjustment and the variance clearance factor. The Mid-peak price, $RPEM_{MID}$, was similarly set. After these two prices were set, and given the forecast levels of consumption during each of the three periods, the On-Peak price, $RPEM_{ON}$, is determined by the requirement for the load-weighted average of TOU prices to equal the RPA.

The various components of Global Adjustment costs are allocated to TOU consumption periods based on the type of cost. The costs associated with OPG's regulated facilities, Bruce Power's nuclear plants, most renewable generation and CDM costs related to conservation programs are allocated uniformly across all consumption. The remaining portion of the CDM cost is allocated only to On-Peak consumption, because the purpose of the demand management portion of CDM is to ensure uninterrupted supply during peak times. Payments to Lennox are also allocated to the On-Peak period, for the same reason. Payments to natural gas generators have been allocated into the Mid-Peak and On-Peak periods. Though the gas generators operate in all three periods, costs for generation in Off-Peak times have been allocated to the On-Peak period, reflecting the system purpose for which many of the facilities were initially contracted: ensuring reliability of supply and being a dispatchable source of power at times of higher demand. The NUG component of the GA is allocated to both Mid-peak and On-Peak consumption because these generators serve non-Off-Peak consumption. As well, approximately one-quarter of the stochastic adjustment was allocated to the Mid-Peak price and three-quarters was allocated to the On-Peak price because the majority of risks covered by the adjustment are borne during these time periods.

The overall effect of this allocation is to set the differential between the On-Peak and Off-Peak prices to 2.0:1. This ratio strengthens the incentive for electricity consumers to shift their consumption away from On-Peak periods, when their electricity prices are highest. Not only is the On-Peak price higher under this scenario, but the Off-Peak price is also lower than it would have been absent this increase to the ratio. A customer with a consumption pattern that mirrors the total TOU consumption would experience no overall bill impact from this change to the ratio, since each of the TOU prices are set so that they collectively recover the same average cost.

The OEB has a number of objectives in setting the RPP. These include setting prices to recover the cost of RPP supply on a forecast basis, as well as ensuring that prices are fair, stable and predictable.

The resulting TOU prices would be the following, absent any consideration of the estimated impact of the proposed Fair Hydro Plan:

- $RPEM_{OFF}$ = 9.1 cents per kWh
- $RPEM_{MID}$ = 13.3 cents per kWh, and
- $RPEM_{ON}$ = 18.5 cents per kWh.

The resulting TOU prices are the following after taking into account the reduction in the forecast amount of the Global Adjustment of approximately $1B:

- $RPEM_{OFF}$ = 7.7 cents per kWh
- $RPEM_{MID}$ = 11.3 cents per kWh, and
- $RPEM_{ON}$ = 15.7 cents per kWh.

These prices reflect the seasonal change in the TOU pricing periods which will take effect on May 1, 2017 and November 1, 2017. As defined in the RPP Manual, the time periods for TOU price application are as follows:

- *Off-Peak* period (priced at $RPEM_{OFF}$):
  - *Winter and summer weekdays*: 7 p.m. to midnight and midnight to 7 a.m.
  - *Winter and summer weekends and holidays*:[20] 24 hours (all day)
- *Mid-Peak* period (priced at $RPEM_{MID}$)
  - *Winter weekdays (November 1 to April 30)*: 11 a.m. to 5 p.m.
  - *Summer weekdays (May 1 to October 31)*: 7 a.m. to 11 a.m. and 5 p.m. to 7 p.m.
- *On-Peak* period (priced at $RPEM_{ON}$)
  - *Winter weekdays*: 7 a.m. to 11 a.m. and 5 p.m. to 7p.m.
  - *Summer weekdays*: 11 a.m. to 5 p.m.

The above times are given in local time (i.e., the times given reflect daylight savings time in the summer).

The average price for a consumer on TOU prices depends on the consumer's load profile (i.e., how much electricity is used at what time). The load profile assumed for TOU consumers is

[20] For the purpose of RPP TOU pricing, a "holiday" means the following days: New Year's Day, Family Day, Good Friday, Christmas Day, Boxing Day, Victoria Day, Canada Day, Labour Day, Thanksgiving Day, and the Civic Holiday. When any holiday falls on a weekend (Saturday or Sunday), the next weekday following (that is not also a holiday) is to be treated as the holiday for RPP TOU pricing purposes.

different from the load profile for non-TOU RPP consumers. RPP prices are set so that a TOU consumer with an average TOU load profile will pay the same average price as an RPP consumer that pays the tiered prices with a typical (non-TOU) load profile. This average price is equal to the RPA.

3.2 Setting the Tiered Prices

The final step in setting the price for RPP consumers with conventional meters is to determine the tiered prices. For these consumers, there is a two-tiered pricing structure: $RPCM_{T1}$ (the price for consumption at or below the tier threshold) and $RPCM_{T2}$ (the price for consumption above the tier threshold). The tier threshold is an amount of consumption per month.

The tiered prices are calculated so that the average per unit revenue generated is equal to the RPA. This is achieved by maintaining the ratio between the original upper and lower tier prices (i.e., the ratio between 4.7 and 5.5 cents per kWh) and forecasting consumption above and below the threshold in each month of the RPP.

RPP tiered prices are set such that the weighted average price will come as close as possible to the RPA, based on the forecast ratio of Tier 1 to Tier 2 consumption, and maintaining a 15-17% difference between Tier 1 and Tier 2 prices.

The resulting tiered prices would be the following, absent any consideration of the estimated impact of the proposed Fair Hydro Plan:

- $RPCM_{T1}$ = 10.7 cents per kWh; and,
- $RPCM_{T2}$ = 12.5 cents per kWh.

The resulting tiered prices are the following after taking into account the reduction in the forecast amount of the Global Adjustment of approximately $1B:

- $RPCM_{T1}$ = 9.1 cents per kWh; and,
- $RPCM_{T2}$ = 10.6 cents per kWh.

Table 5 below summarizes what TOU and tiered prices would have been absent any consideration of the proposed Fair Hydro Plan. Table 6 below summarizes the RPP prices that have been set by the OEB effective May 1, 2017, which reflect consideration of an appropriate portion of the estimated impact of that proposed Plan.

Table 5: Price Otherwise Payable by Average RPP Consumer under TOU and Tiered Prices (Absent any Consideration of the Proposed Fair Hydro Plan)

Time-of-Use RPP Prices	Off-Peak	Mid-Peak	On-Peak	Average Price
Price per kWh	9.1¢	13.3¢	18.5¢	11.5¢
% of TOU Consumption	65%	17%	18%	
Tiered RPP Prices	**Tier 1**		**Tier 2**	**Average Price**
Price per kWh	10.7¢		12.5¢	11.5¢
% of Tiered Consumption	53%		47%	

Table 6: May 1, 2017 RPP Prices

Time-of-Use RPP Prices	Off-Peak	Mid-Peak	On-Peak	Average Price
Price per kWh	7.7¢	11.3¢	15.7¢	9.8¢
% of TOU Consumption	65%	17%	18%	
Tiered RPP Prices	**Tier 1**		**Tier 2**	**Average Price**
Price per kWh	9.1¢		10.6¢	9.8¢
% of Tiered Consumption	53%		47%	

4. Expected Variance

After RPP prices are set, the monthly expected variance can be calculated directly. The variance clearance factor has been set so that the expected variance balance at the end of the RPP period will be as close as possible to zero. This variance clearance factor has been set based on the OEB's usual practice and without consideration of any potential variances related to the changes to the Global Adjustment that are proposed to be a component of the proposed Fair Hydro Plan. The government has indicated that it intends to introduce legislation that would, if passed, enable the refinancing of the Global Adjustment over a longer period of time.

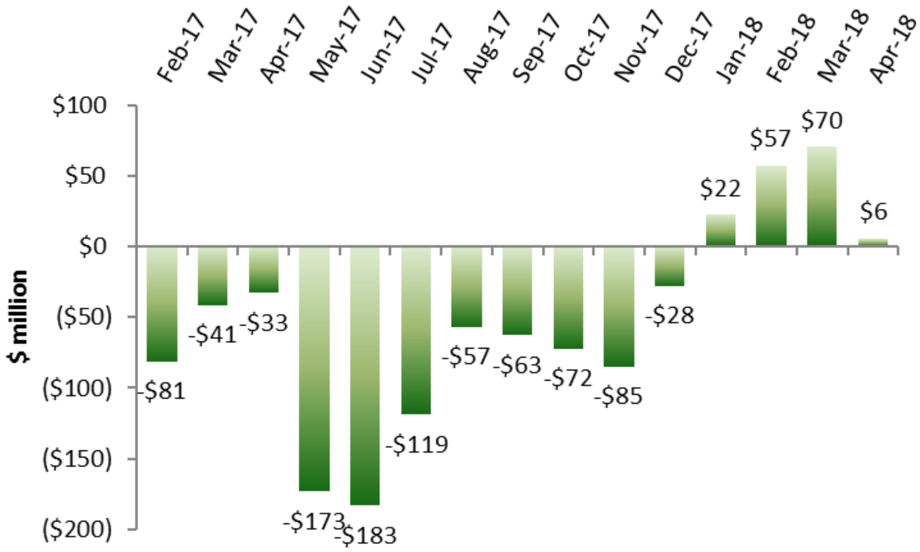
The variance balance is not expected to decline smoothly; the amount of the variance balance cleared is expected to vary significantly from month to month for several reasons:

- Variance clearance will tend to be higher in months when RPP volumes are higher (i.e., summer and winter) and lower when volumes are lower (i.e., spring and fall).
- While there is only technically a single average RPP price (or RPA) in this report, the residential tier thresholds are higher in winter (1000 kWh) than in summer (600 kWh). This means that the average price that RPP consumers on tier prices pay will be lower in winter than in summer, because they will have less consumption at the higher tiered price in the winter. Thus, variance clearance will vary from summer to winter.
- The HOEP is projected to be higher in some months (especially summer) and lower in others (especially the shoulder seasons), but RPP prices remain constant. This will be partially offset by changes in the Global Adjustment. Thus, variance clearance will vary by month, depending on market prices.

Because the RPP prices are rounded to the nearest tenth of a cent, the amount of revenue to be collected cannot be adjusted to exactly clear the variance account. In this case, the RPP prices resulting from the forecast RPA in this report would be expected to collect slightly more than the RPP supply cost, leaving an "expected" credit of $6 million in the variance account at the end of the RPP period, i.e. on April 30, 2018.

The combined effect of these factors is shown in Figure 3. The values in each month of Figure 3 represent the total expected balance in the variance account at the end of each month.

Figure 3: Expected Monthly Variance Account Balance ($ million)



Source: Navigant

CITATION: Rogers Communications Partnership v. Ontario Energy Board, 2016 ONSC 7810
DIVISIONAL COURT FILE NO.: 141/16
DATE: 20161214

ONTARIO

SUPERIOR COURT OF JUSTICE

DIVISIONAL COURT

MOLLOY, DAMBROT and VARPIO JJ.

BETWEEN:	
ROGERS COMMUNICATION PARTNERSHIP, TELUS COMMUNICATIONS COMPANY, QUEBECOR MEDIA INC. and ALLSTREAM INC.	*Jennifer McAleer and Leslie Minton*, for the Appellants
Appellants	*M. Philip Tunley and Pam Hrick*, for the Respondent Ontario Energy Board
– and –	
THE ONTARIO ENERGY BOARD and HYDRO OTTAWA LIMITED	*Fred D. Cass*, for the Respondent Hydro Ottawa Limited
Respondents	
	HEARD: September 29, 2016 in Toronto

REASONS FOR DECISION

MOLLOY J.

A. INTRODUCTION

[1] The Ontario Energy Board ("OEB" or "the Board") issued an Order on February 25, 2016 approving an increase in the rate Hydro Ottawa Limited ("Ottawa Hydro") was permitted to charge to various carriers in order to attach their wireline communications equipment to Hydro Ottawa poles (known as a "pole attachment rate"). The appellants are all carriers affected by the 2016 Order. They participated in the hearing before the OEB and opposed the increased pole

attachment rate sought by Hydro Ottawa. As a result of the 2016 Order, the pole attachment rate was set at $53 per pole, per year, effective January 1, 2016 and continuing indefinitely.

[2] The 2016 Order was the first change to the pole attachment rate since 2005, at which time the rate was set at $22.35 per year for each attacher on a pole. Prior to 2005, cable companies (such as the appellants) rented space on power poles under private contract with the local electricity distributor (such as Hydro Ottawa). In 2003, the Canadian Cable Television Association applied to the OEB requesting a province-wide uniform rate for access to power poles. That application culminated in the OEB issuing an order on March 7, 2005 which, among other things:

(a) accepted that it was in the public interest that there be a province-wide pole attachment rate, which should apply as a condition of all licences granted to local electricity distributors;

(b) established a methodology for calculating the rate, based on an equal sharing approach to common costs;

(c) assumed for purposes of the calculation that on average there would be 2.5 entities attaching to a pole, among whom those common costs would be shared; and

(d) permitted local electricity distributors to apply for a rate modification based on their own costing.

[3] The 2005 pole attachment rate was used uniformly throughout the province for over a decade. The only variation sought was by Toronto Hydro, which application resulted in a 2015 settlement approved by the OEB with a new pole attachment rate of $42 per pole per year.

[4] In the course of the application leading to the 2016 rate change, the appellants sought to persuade the OEB to revisit some of the methodology and assumptions underlying the March 2005 rate order.

[5] However, the OEB determined that it would deal with the Hydro Ottawa application based on the 2005 methodology and would not hear evidence or argument on the reasonableness of that methodology. The OEB determined that it would conduct a comprehensive policy review with respect to the province-wide pole attachment rate, which would include a review of the methodology and components for determining the rate. That process commenced in November 2015 and was still underway as of the date of the argument in this court. Because that process was ongoing, the OEB held that it would base the Hydro Ottawa rates on the 2005 methodology.

B. THE ISSUES

[6] The appellants submit that the OEB, having acknowledged that the 2005 methodology used to set the pole attachment rate needed to be reviewed, erred by setting rates for Hydro

Ottawa based on that outdated and flawed methodology. Further, the appellants characterize this error as a breach of procedural fairness, arguing that the OEB did not give the appellants an opportunity to be heard on the central issue before it; the proper method for determining a just and reasonable rate.

[7] Alternatively, the appellants submit that the OEB fettered its discretion and erred in law and jurisdiction by applying the 2005 methodology. The appellants argue that it is neither reasonable nor possible for the OEB to set a fair rate by using a methodology that the Board acknowledged to require reassessment, while at the same time refusing to consider the appellant's evidence and argument as to what would be a proper methodology.

[8] In addition, the appellants argue that the OEB committed a further breach of procedural fairness by striking their reply record, thereby denying them the right to be heard on the issues raised therein.

[9] Alternatively, the appellants submit that the effect of relying on the old methodology is to improperly remove the burden of proof that should be on Hydro Ottawa to establish a fair rate.

[10] In addition, the appellants specifically challenge the reasonableness of the OEB's decision to assign a value of 5% of common costs for equipment on the pole solely for the use of Hydro Ottawa. The appellant argues that this value is arbitrary and therefore unreasonable.

[11] Finally, and most significantly, the appellants submit that it was unreasonable for the OEB to have made a final order in this situation, as opposed to an interim one. Counsel conceded in argument that if the OEB had characterized its order as interim, the appellants would not have brought this application.

PROCEDURAL FAIRNESS

Standard of Review

[12] With respect to issues of procedural fairness and natural justice, some courts have held there is no standard of review. Rather, once the scope of the duty of procedural fairness is established, the tribunal is simply obliged to observe it. As stated by the Supreme Court of Canada in *Moreau-Bérubé v. New Brunswick (Judicial Council)*[1](at para. 74):

> The [procedural fairness] issue requires no assessment of the appropriate standard of judicial review. Evaluating whether procedural fairness, or the duty of

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[1] *Moreau-Bérubé v. New Brunswick (Judicial Council)*, [2002] 1 S.C.R. 249, 2002 SCC 11; see also *London (City of) v. Ayerswood Development Corp.*, [2002] OJ No 4859; 167 OAC 120; 34 MPLR (3d) 1 (O.C.A.).

> fairness, has been adhered to by a tribunal requires an assessment of the procedures and safeguards required in a particular situation.

[13] In other cases, courts have held that the standard of review for issues of procedural fairness is correctness. For example, the Supreme Court of Canada stated in *Mission Institution v. Khela*[2] that the "standard for determining whether the decision maker complied with the duty of procedural fairness will continue to be 'correctness'."

[14] In my view, how this is characterized does not impact the analysis. The first step for the reviewing court is to decide whether the tribunal is required to observe principles of procedural fairness for the decision at issue and to then determine the scope of the duty owed. The tribunal is required to have complied with the scope of the duty identified by the court, which is essentially the same thing as saying the tribunal must be correct in its application of procedural fairness.

[15] In determining the scope of the duty, the relevant factors to be taken into account were described by the Supreme Court's 1999 decision in *Baker*[3] and have been consistently applied ever since. Although these are acknowledged not to be exclusive factors, the following should be taken into account:

(i) the nature of the decision being made and the process followed to make it;

(ii) the nature of the statutory scheme and the terms of the statute pursuant to which the body operates;

(iii) the importance of the decision to the individual or individuals affected;

(iv) the legitimate expectations of the person challenging the decision; and

(v) the choices of procedure made by the agency itself.

[16] The first four of these factors point to a requirement that the OEB provide the highest degree of procedural fairness. The fifth factor demonstrates that the OEB itself has adopted procedures for hearings that reflect a high standard of procedural fairness. Further, this factor has particular significance in the circumstances of this case.

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[2] *Mission Institution v. Khela*, [2014] 1 S.C.R. 502, 2014 SCC 24 at para. 79; see also *Canada (Citizenship and Immigration) v. Khosa*, [2009] 1 S.C.R. 339, 2009 SCC 12 at para. 43

[3] *Baker v. Canada (Minister of Citizenship and Immigration)*, [1999] 2 S.C.R. 817

[17] The Supreme Court of Canada held in *Knight v. Indian Head School Division*[4] that a tribunal is the master of its own procedure; a principle that has been widely-applied in the jurisprudence. It is natural, therefore, that a tribunal's choice of procedures is a factor in determining the precise scope of procedural fairness in proceedings before it. As noted by Stratas J.A. in *Forest Ethics Advocacy Association v. Canada (National Energy Board)*[5] (in reference to the National Energy Board, a tribunal very similar in nature to the OEB):

> The Board has considerable experience and expertise in conducting its own hearings and determining who should not participate, who should participate, how and to what extent. It also has considerable experience and expertise in ensuring that its hearings deal with the issues mandated by the Act in a timely and efficient way.

[18] Thus, although the standard of review for procedural fairness is correctness, in determining the scope of procedural fairness for a particular procedural decision by a tribunal, there is a degree of deference. Evans J.A. in *Re: Sound v. Fitness Industry Council of Canada*,[6] described it this way (at para. 42):

> In short, whether an agency's procedural arrangements, general or specific, comply with the duty of fairness is for a reviewing court to decide on the correctness standard, but in making that determination it must be respectful of the agency's choices. It is thus appropriate for a reviewing court to give weight to the manner in which an agency has sought to balance maximum participation on the one hand, and efficient and effective decision-making on the other. In recognition of the agency's expertise, a degree of deference to an administrator's procedural choice may be particularly important when the procedural model of the agency under review differs significantly from the judicial model with which courts are most familiar.

Application to this Case

[19] The OEB's decision with respect to which methodology to use in setting rates is not easily characterized as being procedural as opposed to substantive. On the one hand, the OEB chose to apply the existing methodology rather than implementing changes to it – a decision that could be said to be substantive, within its area of expertise, and subject to a reasonableness standard. On the other hand, it cannot be denied that the methodology to be used to determine a rate is a relevant factor in setting that rate and the appellants were prevented from eliciting

[4] *Knight v. Indian Head School Division No. 19*, [1990] 1 S.C.R. 653 at 685; see also *Prassad v. Canada (Minister of Employment and Immigration)*, [1989] 1 S.C.R. 560 at 568-569
[5] *Forest Ethics Advocacy Association v. Canada (National Energy Board)*, 2014 FCA 245 at para. 72
[6] *Re: Sound v. Fitness Industry Council of Canada*, 2014 FCA 48

evidence as to the appropriate methodology – a decision that could be characterized as a denial of the right to be heard on a relevant issue; a fundamental tenet of procedural fairness.

[20] However, in my opinion, this dichotomy is easily reconciled in this case by affording appropriate deference in determining the scope of the duty of procedural fairness owed by the OEB in this situation. The OEB did not refuse to reconsider the 2005 methodology. On the contrary, it recognized the need to review and modify it. All the OEB did was determine the appropriate procedure and timing for deciding the new methodology. The Board decided that this was a policy decision with broad ramifications and should be undertaken as a province-wide review with all stakeholders, including the appellants, having an opportunity to participate. In that way, the Board was providing the broadest participation rights possible, rather than making a decision in one geographic area which could have ramifications for other areas of the province and affect others who had no opportunity to be heard. Seen this way, the Board was enhancing, rather than circumventing, procedural fairness. Further, the Board did not simply avoid the issue of methodology. It proceeded promptly and the province-wide review was already underway prior to the issuance of the Board decision now before this Court.

[21] The OEB is in the best position to determine when and how to make a major policy decision such as this one. It is also in the best position to decide the potential impact of making a decision in one sector that could affect others without a broader consultation. In deciding its own procedure for how it would revisit the 2005 methodology, the OEB is drawing on its core expertise and is entitled to deference. Within that broader consultation, principles of procedural fairness will still apply.

[22] I do not consider the OEB to have breached procedural fairness by telling the appellants in this case that the time and place for them to challenge the 2005 methodology is within the broader policy review, rather than in this particular hearing dealing only with Hydro Ottawa.

[23] The other alleged procedural fairness breach relates to reply submissions delivered by the appellants. The Board conducted pre-hearing consultations to work out an appropriate procedure and schedule for submissions. No provision was made for reply submissions. Given that the whole procedure and all of the issues were known to the parties, a procedure that does not include an opportunity for reply is not, *per se*, a breach of procedural fairness. When the appellants attempted to file reply submissions based on its assertions that four new issues had been raised, the Board ruled that three of these issues had been raised earlier and the appellants were therefore not prejudiced by not having an opportunity to file reply submissions. With respect to the fourth point, the Board held that this point would not be dealt with in its decision and reply submissions were therefore not necessary. The Board noted that permitting a reply by these applicants would require granting the same right to all parties, thereby delaying and extending the proceedings for no good reason. The Board therefore determined that it would not take the reply submissions into account in making its decision.

[24] The Board imposed a fair process, respecting the rights of all parties to be heard, and it applied that process consistently. These are issues upon which the Board is entitled to deference, as master of its own procedure. I find no breach of procedural fairness.

FETTERING DISCRETION AND BURDEN OF PROOF

[25] The OEB decided that it would have a broad consultative process to set the methodology for determining rates. That is how the 2005 methodology was developed. It was completely reasonable for the Board to have done so, and to apply that methodology consistently throughout the province. That does not constitute fettering of discretion. It was always open to the Board to vary the 2005 methodology and, indeed, it has undertaken that very process in its ongoing policy review. Consistently applying a methodology until a new methodology has been devised cannot be seen to change the burden of proof, nor can it be characterized as fettering discretion. The Board is not required to constantly re-invent the wheel by revisiting the methodology and starting from point zero in every single case.

[26] I see no merit to this argument. By proceeding in this way, the Board acted reasonably and did not breach procedural fairness.

REASONABLENESS

Applying the 2005 Methodology

[27] The appellants also argued that it was unreasonable for the OEB to have made a decision in this case without addressing the deficiencies in the 2005 methodology. I disagree. The OEB engaged in a broad consultative process before setting the 2005 methodology. The Board determined that it would be appropriate to continue applying that methodology until such time as it was replaced or modified by a new methodology developed in the same manner. This is a broad policy issue, about which the OEB is far more knowledgeable and well-positioned to decide than is this court. Deference is required. The Board's decision was a reasonable one, supported by cogent, policy-based reasons. There is no basis to interfere.

Interim or Final Nature of the Order

[28] Having determined to defer any changes to the 2005 methodology until after the broad Policy Review, the OEB invited the parties to provide submissions as to whether its decision in this case should be on an interim basis pending that Policy Review. In due course, the parties made submissions on the point and the Board held that its decision would be final, rather than interim. Having considered those submissions, the Board ruled that its order in this case would be prospective in its effect, rather than interim. The Board held that this was consistent with the stance taken in other OEB decisions involving new policies. The Board found that the new pole attachment rate should be prospective as of January 1, 2016 to provide rate certainty to the third-party wireline attachers and revenue certainty to Hydro Ottawa. These are relevant and

important considerations, in keeping with the OEB's mandate to govern the industry fairly in the interests of consumers as well as industry participants. Certainly, a compelling argument could also be made for an interim order. However, the option chosen by the OEB is a rational outcome and is supported by the evidence and reasons provided. There is no basis for finding it to be unreasonable.

The Common Costs Analysis

[29] Finally, the appellants object to the OEB's finding that there should only be a 5% adjustment to the rate in order to reflect power-specific fixtures on the poles that are of no benefit to third party attachers such as the appellants. The appellants had argued before the Board that a 15% adjustment should have been made and submitted to this Court that the Board's decision to make only a 5% adjustment was arbitrary, not based in the evidence and unreasonable.

[30] In its reasons, the Board referred to the submissions of the parties as to which of the two adjustment rates should apply. The Board also referred to the evidence provided by Hydro Ottawa as to the actual configuration of its assets (using brackets rather than crossarms in its distribution system construction), which was evidence canvassed at the technical conference. Based on this, the Board concluded that the 5% adjustment rate was more appropriate.

[31] This was a finding of fact open to the Board on an issue squarely within its area of expertise. It is a reasonable finding, supported by evidence, for which the Board provided rational reasons.

[32] There is no basis for this Court to interfere.

CONCLUSION

[33] Accordingly, this application is dismissed. If the parties are unable to agree on costs, written submissions may be forwarded through the Divisional Court office, on a timetable to be agreed upon by counsel, with all submissions to be filed by no later than January 30, 2017.

MOLLOY J.

I agree:

DAMBROT J.

I agree:

VARPIO J.

Released: December 14, 2016

CITATION: Rogers Communications Partnership v. Ontario Energy Board, 2016 ONSC 7810
DIVISIONAL COURT FILE NO.: 141/16
DATE: 20161214

ONTARIO

SUPERIOR COURT OF JUSTICE

DIVISIONAL COURT

MOLLOY, DAMBROT and VARPIO JJ.

BETWEEN:

ROGERS COMMUNICATION PARTNERSHIP, TELUS COMMUNICATIONS COMPANY, QUEBECOR MEDIA INC. and ALLSTREAM INC.

Appellants

– and –

THE ONTARIO ENERGY BOARD and HYDRO OTTAWA LIMITED

Respondents

REASONS FOR DECISION

Molloy J./Divisional Court

Released: December 14, 2016

Mavis Baker *Appellant*

v.

Minister of Citizenship and Immigration *Respondent*

and

The Canadian Council of Churches, the Canadian Foundation for Children, Youth and the Law, the Defence for Children International-Canada, the Canadian Council for Refugees, and the Charter Committee on Poverty Issues *Interveners*

INDEXED AS: BAKER *v.* CANADA (MINISTER OF CITIZENSHIP AND IMMIGRATION)

File No.: 25823.

1998: November 4; 1999: July 9.

Present: L'Heureux-Dubé, Gonthier, Cory, McLachlin, Iacobucci, Bastarache and Binnie JJ.

ON APPEAL FROM THE FEDERAL COURT OF APPEAL

Immigration — Humanitarian and compassionate considerations — Children's interests — Woman with Canadian-born dependent children ordered deported — Written application made on humanitarian and compassionate grounds for exemption to requirement that application for immigration be made abroad — Application denied without hearing or formal reasons — Whether procedural fairness violated — Immigration Act, R.S.C., 1985, c. I-2, ss. 82.1(1), 114(2) — Immigration Regulations, 1978, SOR/93-44, s. 2.1 — Convention on the Rights of the Child, Can. T.S. 1992 No. 3, Arts. 3, 9, 12.

Administrative law — Procedural fairness — Woman with Canadian-born dependent children ordered deported — Written application made on humanitarian and compassionate grounds for exemption to requirement that application for immigration be made abroad — Whether participatory rights accorded consistent with duty of procedural fairness — Whether failure to provide reasons violated principles of procedural fairness — Whether reasonable apprehension of bias.

Mavis Baker *Appelante*

c.

Le ministre de la Citoyenneté et de l'Immigration *Intimé*

et

Le Conseil canadien des églises, la Canadian Foundation for Children, Youth and the Law, la Défense des enfants-International-Canada, le Conseil canadien pour les réfugiés et le Comité de la Charte et des questions de pauvreté *Intervenants*

RÉPERTORIÉ: BAKER *c.* CANADA (MINISTRE DE LA CITOYENNETÉ ET DE L'IMMIGRATION)

N[o] du greffe: 25823.

1998: 4 novembre; 1999: 9 juillet.

Présents: Les juges L'Heureux-Dubé, Gonthier, Cory, McLachlin, Iacobucci, Bastarache et Binnie.

EN APPEL DE LA COUR D'APPEL FÉDÉRALE

Immigration — Raisons d'ordre humanitaire — Intérêts des enfants — Mesure d'expulsion contre une mère d'enfants nés au Canada — Demande écrite fondée sur des raisons d'ordre humanitaire sollicitant une dispense de l'exigence de présenter à l'extérieur du Canada une demande d'immigration — Demande rejetée sans audience ni motifs écrits — Y a-t-il eu violation de l'équité procédurale? — Loi sur l'immigration, L.R.C. (1985), ch. I-2, art. 82.1(1), 114(2) — Règlement sur l'immigration de 1978, DORS/93-44, art. 2.1 — Convention relative aux droits de l'enfant, R.T. Can. 1992 n[o] 3, art. 3, 9, 12.

Droit administratif – Équité procédurale — Mesure d'expulsion contre une mère d'enfants nés au Canada — Demande écrite fondée sur des raisons d'ordre humanitaire sollicitant une dispense de l'exigence de présenter à l'extérieur du Canada une demande d'immigration — Les droits de participation accordés étaient-ils compatibles avec l'obligation d'équité procédurale? — Le défaut d'exposer les motifs de décision a-t-il enfreint les principes d'équité procédurale? — Y a-t-il une crainte raisonnable de partialité?

Courts — Appellate review — Judge on judicial review certifying question for consideration of Court of Appeal — Legal effect of certified question — Immigration Act, R.S.C., 1985, c. I-2, s. 83(1).

Immigration — Humanitarian and compassionate considerations — Standard of review of humanitarian and compassionate decision — Best interests of claimant's children — Approach to be taken in reviewing humanitarian and compassionate decision where children affected.

Administrative law — Review of discretion — Approach to review of discretionary decision making.

The appellant, a woman with Canadian-born dependent children, was ordered deported. She then applied for an exemption, based on humanitarian and compassionate considerations under s. 114(2) of the *Immigration Act*, from the requirement that an application for permanent residence be made from outside Canada. This application was supported by letters indicating concern about the availability of medical treatment in her country of origin and the effect of her possible departure on her Canadian-born children. A senior immigration officer replied by letter stating that there were insufficient humanitarian and compassionate reasons to warrant processing the application in Canada. This letter contained no reasons for the decision. Counsel for the appellant, however, requested and was provided with the notes made by the investigating immigration officer and used by the senior officer in making his decision. The Federal Court — Trial Division, dismissed an application for judicial review but certified the following question pursuant to s. 83(1) of the Act: "Given that the Immigration Act does not expressly incorporate the language of Canada's international obligations with respect to the International Convention on the Rights of the Child, must federal immigration authorities treat the best interests of the Canadian child as a primary consideration in assessing an applicant under s. 114(2) of the *Immigration Act*?" The Court of Appeal limited its consideration to the question and found that the best interests of the children did not need to be given primacy in assessing such an application. The order that the appellant be removed from Canada, which was made after the immigration officer's decision, was stayed pending the result of this appeal.

Tribunaux — Contrôle en appel — Certification, par le juge siégeant en contrôle judiciaire, d'une question à soumettre à la Cour d'appel — Effet juridique d'une question certifiée — Loi sur l'immigration, L.R.C. (1985), ch. I-2, art. 83(1).

Immigration — Raisons d'ordre humanitaire — Norme de contrôle d'une décision fondée sur des raisons d'ordre humanitaire — Intérêt supérieur des enfants de la demanderesse — Approche du contrôle d'une décision fondée sur des raisons d'ordre humanitaire touchant des enfants.

Droit administratif — Contrôle du pouvoir discrétionnaire — Approche du contrôle de décisions discrétionnaires.

Une mesure d'expulsion a été prise contre l'appelante, mère d'enfants à charge nés au Canada. Elle a alors demandé d'être dispensée de faire sa demande de résidence permanente de l'extérieur du Canada, pour des raisons d'ordre humanitaire, conformément au par. 114(2) de la *Loi sur l'immigration*. Sa demande était appuyée de lettres exprimant des inquiétudes quant à la possibilité d'obtenir un traitement médical dans son pays d'origine et quant à l'effet de son départ éventuel sur ses enfants nés au Canada. Un agent d'immigration supérieur a répondu par lettre qu'il n'y avait pas suffisamment de raisons humanitaires pour justifier de traiter sa demande au Canada. Cette lettre ne donnait pas les motifs de la décision. L'avocat de l'appelante a cependant demandé et reçu les notes de l'agent investigateur, que l'agent supérieur d'immigration avait utilisées pour rendre sa décision. La Section de première instance de la Cour fédérale a rejeté une demande de contrôle judiciaire mais a certifié la question suivante en application du par. 83(1) de la Loi: «Vu que la Loi sur l'immigration n'incorpore pas expressément le langage des obligations internationales du Canada en ce qui concerne la Convention internationale relative aux droits de l'enfant, les autorités d'immigration fédérales doivent-elles considérer l'intérêt supérieur de l'enfant né au Canada comme une considération primordiale dans l'examen du cas d'un requérant sous le régime du par. 114(2) de la *Loi sur l'immigration*?» La Cour d'appel a limité son examen à cette question et a conclu qu'il n'était pas nécessaire d'accorder la primauté à l'intérêt supérieur des enfants dans l'appréciation d'une telle demande. Un sursis à la mesure d'expulsion de l'appelante prononcée après la décision de l'agent d'immigration, a été ordonné jusqu'à l'issue du présent pourvoi.

Held: The appeal should be allowed.

Per L'Heureux-Dubé, Gonthier, McLachlin, Bastarache and Binnie JJ.: Section 83(1) of the *Immigration Act* does not require the Court of Appeal to address only the certified question. Once a question has been certified, the Court of Appeal may consider all aspects of the appeal lying within its jurisdiction.

The duty of procedural fairness is flexible and variable and depends on an appreciation of the context of the particular statute and the rights affected. The purpose of the participatory rights contained within it is to ensure that administrative decisions are made using a fair and open procedure, appropriate to the decision being made and its statutory, institutional and social context, with an opportunity for those affected to put forward their views and evidence fully and have them considered by the decision-maker. Several factors are relevant to determining the content of the duty of fairness: (1) the nature of the decision being made and process followed in making it; (2) the nature of the statutory scheme and the terms of the statute pursuant to which the body operates; (3) the importance of the decision to the individual or individuals affected; (4) the legitimate expectations of the person challenging the decision; (5) the choices of procedure made by the agency itself. This list is not exhaustive.

A duty of procedural fairness applies to humanitarian and compassionate decisions. In this case, there was no legitimate expectation affecting the content of the duty of procedural fairness. Taking into account the other factors, although some suggest stricter requirements under the duty of fairness, others suggest more relaxed requirements further from the judicial model. The duty of fairness owed in these circumstances is more than minimal, and the claimant and others whose important interests are affected by the decision in a fundamental way must have a meaningful opportunity to present the various types of evidence relevant to their case and have it fully and fairly considered. Nevertheless, taking all the factors into account, the lack of an oral hearing or notice of such a hearing did not constitute a violation of the requirement of procedural fairness. The opportunity to produce full and complete written documentation was sufficient.

It is now appropriate to recognize that, in certain circumstances, including when the decision has important significance for the individual, or when there is a statutory right of appeal, the duty of procedural fairness will require a written explanation for a decision. Reasons are

Arrêt: Le pourvoi est accueilli.

Les juges L'Heureux-Dubé, Gonthier, McLachlin, Bastarache et Binnie: Le paragraphe 83(1) de la *Loi sur l'immigration* n'exige pas que la Cour d'appel traite seulement la question certifiée. Lorsqu'une question a été certifiée, la Cour d'appel peut examiner tous les aspects de l'appel qui relèvent de sa compétence.

L'obligation d'équité procédurale est souple et variable et repose sur une appréciation du contexte de la loi et des droits visés. Les droits de participation qui en font partie visent à garantir que les décisions administratives sont prises au moyen d'une procédure équitable et ouverte, adaptée au type de décision et à son contexte légal, institutionnel et social, comprenant la possibilité donnée aux personnes visées de présenter leur point de vue et des éléments de preuve qui seront dûment pris en considération par le décideur. Plusieurs facteurs sont pertinents pour déterminer le contenu de l'obligation d'équité procédurale: (1) la nature de la décision recherchée et le processus suivi pour y parvenir; (2) la nature du régime législatif et les termes de la loi régissant l'organisme; (3) l'importance de la décision pour les personnes visées; (4) les attentes légitimes de la personne qui conteste la décision; (5) les choix de procédure que l'organisme fait lui-même. Cette liste de facteurs n'est pas exhaustive.

L'obligation d'équité procédurale s'applique aux décisions d'ordre humanitaire. En l'espèce, il n'y avait pas d'attente légitime ayant une incidence sur la nature de l'obligation d'équité procédurale. Compte tenu des autres facteurs, bien que certains indiquent des exigences plus strictes en vertu de l'obligation d'équité, d'autres indiquent des exigences moins strictes et plus éloignées du modèle judiciaire. L'obligation d'équité dans ces circonstances est plus que minimale, et le demandeur et les personnes dont les intérêts sont profondément touchés par la décision doivent avoir une possibilité valable de présenter les divers types de preuves qui se rapportent à leur affaire et de les voir évalués de façon complète et équitable. Néanmoins, compte tenu de tous ces facteurs, le fait qu'il n'y ait pas eu d'audience ni d'avis d'audience ne constituait pas un manquement à l'obligation d'équité procédurale. La possibilité de produire une documentation écrite complète était suffisante.

Il est maintenant approprié de reconnaître que, dans certaines circonstances, notamment lorsque la décision revêt une grande importance pour l'individu, ou lorsqu'il existe un droit d'appel prévu par la loi, l'obligation d'équité procédurale requerra une explication écrite de required here given the profound importance of this decision to those affected. This requirement was fulfilled by the provision of the junior immigration officer's notes, which are to be taken to be the reasons for decision. Accepting such documentation as sufficient reasons upholds the principle that individuals are entitled to fair procedures and open decision-making, but recognizes that, in the administrative context, this transparency may take place in various ways.

Procedural fairness also requires that decisions be made free from a reasonable apprehension of bias, by an impartial decision-maker. This duty applies to all immigration officers who play a role in the making of decisions. Because they necessarily relate to people of diverse backgrounds, from different cultures, races, and continents, immigration decisions demand sensitivity and understanding by those making them. They require a recognition of diversity, an understanding of others, and an openness to difference. Statements in the immigration officer's notes gave the impression that he may have been drawing conclusions based not on the evidence before him, but on the fact that the appellant was a single mother with several children and had been diagnosed with a psychiatric illness. Here, a reasonable and well-informed member of the community would conclude that the reviewing officer had not approached this case with the impartiality appropriate to a decision made by an immigration officer. The notes therefore give rise to a reasonable apprehension of bias.

The concept of discretion refers to decisions where the law does not dictate a specific outcome, or where the decision-maker is given a choice of options within a statutorily imposed set of boundaries. Administrative law has traditionally approached the review of decisions classified as discretionary separately from those seen as involving the interpretation of rules of law. Review of the substantive aspects of discretionary decisions is best approached within the pragmatic and functional framework defined by this Court's decisions, especially given the difficulty in making rigid classifications between discretionary and non-discretionary decisions. Though discretionary decisions will generally be given considerable respect, that discretion must be exercised in accordance with the boundaries imposed in the statute, the principles of the rule of law, the principles of administrative law, the fundamental values of Canadian society, and the principles of the *Charter*.

la décision. Des motifs écrits sont nécessaires en l'espèce, étant donné l'importance cruciale de la décision pour les personnes visées. Cette obligation a été remplie par la production des notes de l'agent subalterne, qui doivent être considérées comme les motifs de la décision. L'admission de ces documents comme motifs de la décision confirme le principe selon lequel les individus ont droit à une procédure équitable et à la transparence de la prise de décision, mais reconnaît aussi qu'en matière administrative, cette transparence peut être atteinte de différentes façons.

L'équité procédurale exige également que les décisions soient rendues par un décideur impartial, sans crainte raisonnable de partialité. Cette obligation s'applique à tous les agents d'immigration qui jouent un rôle significatif dans la prise de décision. Parce qu'elles visent nécessairement des personnes de provenances diverses, issues de cultures, de races et de continents différents, les décisions en matière d'immigration exigent de ceux qui les rendent sensibilité et compréhension. Elles exigent la reconnaissance de la diversité, la compréhension des autres et l'ouverture d'esprit à la différence. Les déclarations contenues dans les notes de l'agent d'immigration donnent l'impression qu'il peut avoir tiré des conclusions en se fondant non pas sur la preuve dont il disposait, mais sur le fait que l'appelante était une mère célibataire ayant plusieurs enfants, et était atteinte de troubles psychiatriques. En l'espèce, un membre raisonnable et bien informé de la communauté conclurait que l'agent n'a pas traité cette affaire avec l'impartialité requise dans une décision rendue par un agent d'immigration. Les notes donnent donc lieu à une crainte raisonnable de partialité.

La notion de pouvoir discrétionnaire s'applique dans les cas où le droit ne dicte pas une décision précise, ou quand le décideur se trouve devant un choix d'options à l'intérieur de limites imposées par la loi. Le droit administratif a traditionnellement abordé le contrôle judiciaire des décisions discrétionnaires séparément de décisions sur l'interprétation de règles de droit. Le contrôle des éléments de fond d'une décision discrétionnaire est mieux envisagé selon la démarche pragmatique et fonctionnelle définie par la jurisprudence de notre Cour, compte tenu particulièrement de la difficulté de faire des classifications rigides entre les décisions discrétionnaires et les décisions non discrétionnaires. Même si en général il sera accordé un grand respect aux décisions discrétionnaires, il faut que le pouvoir discrétionnaire soit exercé conformément aux limites imposées dans la loi, aux principes de la primauté du droit, aux principes du droit administratif, aux valeurs fondamentales de la société canadienne, et aux principes de la *Charte*.

In applying the applicable factors to determining the standard of review, considerable deference should be accorded to immigration officers exercising the powers conferred by the legislation, given the fact-specific nature of the inquiry, its role within the statutory scheme as an exception, and the considerable discretion evidenced by the statutory language. Yet the absence of a privative clause, the explicit contemplation of judicial review by the Federal Court — Trial Division, and the individual rather than polycentric nature of the decision also suggest that the standard should not be as deferential as "patent unreasonableness". The appropriate standard of review is, therefore, reasonableness *simpliciter*.

Dans l'application des facteurs pertinents à la détermination de la norme de contrôle appropriée, on devrait faire preuve d'une retenue considérable envers les décisions d'agents d'immigration exerçant les pouvoirs conférés par la loi, compte tenu de la nature factuelle de l'analyse, de son rôle d'exception au sein du régime législatif et de la large discrétion accordée par le libellé de la loi. Toutefois, l'absence de clause privative, la possibilité expressément prévue d'un contrôle judiciaire par la Cour fédérale — Section de première instance, ainsi que la nature individuelle plutôt que polycentrique de la décision, tendent aussi à indiquer que la norme applicable ne devrait pas en être une d'aussi grande retenue que celle du caractère «manifestement déraisonnable». La norme de contrôle appropriée est celle de la décision raisonnable *simpliciter*.

The wording of the legislation shows Parliament's intention that the decision be made in a humanitarian and compassionate manner. A reasonable exercise of the power conferred by the section requires close attention to the interests and needs of children since children's rights, and attention to their interests, are central humanitarian and compassionate values in Canadian society. Indications of these values may be found in the purposes of the Act, in international instruments, and in the Minister's guidelines for making humanitarian and compassionate decisions. Because the reasons for this decision did not indicate that it was made in a manner which was alive, attentive, or sensitive to the interests of the appellant's children, and did not consider them as an important factor in making the decision, it was an unreasonable exercise of the power conferred by the legislation. In addition, the reasons for decision failed to give sufficient weight or consideration to the hardship that a return to the appellant's country of origin might cause her.

Le libellé de la législation révèle l'intention du Parlement de faire en sorte que la décision soit fondée sur des raisons d'ordre humanitaire. L'exercice raisonnable du pouvoir conféré par l'article exige que soit prêtée une attention minutieuse aux intérêts et aux besoins des enfants puisque les droits des enfants, et la considération de leurs intérêts, sont des valeurs humanitaires centrales dans la société canadienne. Une indication de ces valeurs se trouve dans les objectifs de la Loi, dans les instruments internationaux, et dans les lignes directrices régissant les décisions d'ordre humanitaire publiées par le ministre. Étant donné que les motifs de la décision n'indiquent pas qu'elle a été rendue d'une manière réceptive, attentive ou sensible à l'intérêt des enfants de l'appelante, ni que leur intérêt a été considéré comme un facteur décisionnel important, elle constituait un exercice déraisonnable du pouvoir conféré par la loi. En outre, les motifs de la décision n'accordent pas suffisamment d'importance ou de poids aux difficultés qu'un retour de l'appelante dans son pays d'origine pouvait lui susciter.

Per Cory and Iacobucci JJ.: The reasons and disposition of L'Heureux-Dubé J. were agreed with apart from the effect of international law on the exercise of ministerial discretion under s. 114(2) of the *Immigration Act*. The certified question must be answered in the negative. The principle that an international convention ratified by the executive is of no force or effect within the Canadian legal system until incorporated into domestic law does not survive intact the adoption of a principle of law which permits reference to an unincorporated convention during the process of statutory interpretation.

Les juges Cory et Iacobucci: Les motifs du juge L'Heureux-Dubé et le dispositif qu'elle propose sont acceptés sauf pour ce qui concerne la question de l'effet du droit international sur l'exercice du pouvoir discrétionnaire conféré au ministre par le par. 114(2) de la *Loi sur l'immigration*. La question certifiée devrait recevoir une réponse négative. Le principe qu'une convention internationale ratifiée par le pouvoir exécutif n'a aucun effet en droit canadien tant qu'elle n'est pas incorporée dans le droit interne ne peut pas survivre intact après l'adoption d'un principe de droit qui autorise le recours dans le processus d'interprétation des lois, aux dispositions d'une convention qui n'a pas été intégrée dans la législation.

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Roger Rowe and *Rocco Galati*, for the appellant.

Urszula Kaczmarczyk and *Cheryl D. Mitchell*, for the respondent.

Sheena Scott and *Sharryn Aiken*, for the interveners the Canadian Foundation for Children,

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POURVOI contre un arrêt de la Cour d'appel fédérale, [1997] 2 C.F. 127, 207 N.R. 57, 142 D.L.R. (4th) 554, [1996] A.C.F. nº 1726 (QL), qui a rejeté un appel d'un jugement du juge Simpson (1995), 101 F.T.R. 110, 31 Imm. L.R. (2d) 150, [1995] A.C.F. nº 1441 (QL), qui avait rejeté une demande de contrôle judiciaire. Pourvoi accueilli.

Roger Rowe et *Rocco Galati*, pour l'appelante.

Urszula Kaczmarczyk et *Cheryl D. Mitchell*, pour l'intimé.

Sheena Scott et *Sharryn Aiken*, pour les intervenants la Canadian Foundation for Children, Youth

Youth and the Law, the Defence for Children International-Canada, and the Canadian Council for Refugees.

John Terry and *Craig Scott*, for the intervener the Charter Committee on Poverty Issues.

Barbara Jackman and *Marie Chen*, for the intervener the Canadian Council of Churches.

The judgment of L'Heureux-Dubé, Gonthier, McLachlin, Bastarache and Binnie JJ. was delivered by

L'HEUREUX-DUBÉ J. — Regulations made pursuant to s. 114(2) of the *Immigration Act*, R.S.C., 1985, c. I-2, empower the respondent Minister to facilitate the admission to Canada of a person where the Minister is satisfied, owing to humanitarian and compassionate considerations, that admission should be facilitated or an exemption from the regulations made under the Act should be granted. At the centre of this appeal is the approach to be taken by a court to judicial review of such decisions, both on procedural and substantive grounds. It also raises issues of reasonable apprehension of bias, the provision of written reasons as part of the duty of fairness, and the role of children's interests in reviewing decisions made pursuant to s. 114(2).

I. Factual Background

Mavis Baker is a citizen of Jamaica who entered Canada as a visitor in August of 1981 and has remained in Canada since then. She never received permanent resident status, but supported herself illegally as a live -in domestic worker for 11 years. She has had four children (who are all Canadian citizens) while living in Canada: Paul Brown, born in 1985, twins Patricia and Peter Robinson, born in 1989, and Desmond Robinson, born in 1992. After Desmond was born, Ms. Baker suffered from post-partum psychosis and was diagnosed with paranoid schizophrenia. She applied for welfare at that time. When she was first diagnosed with mental illness, two of her children were placed in the care of their

and the Law, la Défense des enfants-International-Canada et le Conseil canadien pour les réfugiés.

John Terry et *Craig Scott*, pour l'intervenant le Comité de la Charte et des questions de pauvreté.

Barbara Jackman et *Marie Chen*, pour l'intervenant le Conseil canadien des églises.

Version française du jugement des juges L'Heureux-Dubé, Gonthier, McLachlin, Bastarache et Binnie rendu par

LE JUGE L'HEUREUX-DUBÉ — Le règlement passé en vertu du par. 114(2) de la *Loi sur l'immigration*, L.R.C. (1985), ch. I-2, autorise le ministre intimé à faciliter l'admission au Canada d'une personne quand il est convaincu, pour des raisons d'ordre humanitaire, que l'admission devrait être facilitée ou qu'une dispense d'application des règlements passés aux termes de la Loi devrait être accordée. Le présent pourvoi porte essentiellement sur la démarche à suivre lorsqu'un tribunal procède au contrôle judiciaire de ces décisions, à la fois sur le fond et sur le plan de la procédure. Ce pourvoi soulève également des questions relatives à la crainte raisonnable de partialité, à la rédaction de motifs écrits dans le cadre de l'obligation d'agir équitablement et au rôle de l'intérêt des enfants dans le contrôle judiciaire de décisions rendues conformément au par. 114(2). 1

I. Les faits

Mavis Baker, citoyenne de la Jamaïque, est entrée au Canada à titre de visiteur en août 1981 et y vit depuis. Elle n'a jamais obtenu le statut de résidente permanente, mais a subvenu illégalement à ses besoins en travaillant pendant 11 ans comme travailleur domestique. Elle a eu quatre enfants (qui sont tous citoyens canadiens) au Canada: Paul Brown, né en 1985, les jumeaux Patricia et Peter Robinson, nés en 1989, et Desmond Robinson, né en 1992. Après la naissance de Desmond, M^me^ Baker a souffert d'une psychose post-partum et on a diagnostiqué qu'elle était atteinte d'une schizophrénie paranoïde. À cette époque, elle a présenté une demande d'assistance sociale. Quand 2 natural father, and the other two were placed in foster care. The two who were in foster care are now again under her care, since her condition has improved.

on a découvert qu'elle était atteinte de troubles mentaux, deux de ses enfants ont été confiés aux soins de leur père naturel et les deux autres ont été placés en foyer d'accueil. Son état s'étant amélioré, elle a de nouveau la garde des deux enfants placés en foyer d'accueil.

3 The appellant was ordered deported in December 1992, after it was determined that she had worked illegally in Canada and had overstayed her visitor's visa. In 1993, Ms. Baker applied for an exemption from the requirement to apply for permanent residence outside Canada, based upon humanitarian and compassionate considerations, pursuant to s. 114(2) of the *Immigration Act*. She had the assistance of counsel in filing this application, and included, among other documentation, submissions from her lawyer, a letter from her doctor, and a letter from a social worker with the Children's Aid Society. The documentation provided indicated that, although she was still experiencing psychiatric problems, she was making progress. It also stated that she might become ill again if she were forced to return to Jamaica, since treatment might not be available for her there. Ms. Baker's submissions also clearly indicated that she was the sole caregiver for two of her Canadian-born children, and that the other two depended on her for emotional support and were in regular contact with her. The documentation suggested that she too would suffer emotional hardship if she were separated from them.

En décembre 1992, une ordonnance d'expulsion a été prise contre l'appelante, lorsqu'on a découvert qu'elle avait travaillé illégalement au Canada et avait séjourné au-delà de son visa de visiteur. En 1993, M^me^ Baker a demandé d'être dispensée de faire sa demande de résidence permanente de l'extérieur du Canada, pour des raisons d'ordre humanitaire, conformément au par. 114(2) de la *Loi sur l'immigration*. Elle a obtenu l'aide d'un avocat pour remplir cette demande, et a notamment ajouté, comme documents additionnels, des observations de son avocat, une lettre de son médecin et une lettre d'un travailleur social de la Société d'aide à l'enfance. Les documents présentés indiquaient que, même si elle éprouvait toujours des problèmes psychiatriques, elle faisait des progrès, mais qu'elle pourrait retomber malade si elle était forcée de retourner en Jamaïque, parce qu'elle ne pourrait peut-être pas y bénéficier d'un traitement. Madame Baker a aussi clairement indiqué qu'elle était la seule à pouvoir prendre soin de deux de ses enfants nés au Canada et que ses deux autres enfants avaient besoin de son soutien affectif et étaient régulièrement en contact avec elle. Les documents mentionnaient également qu'elle subirait aussi des difficultés d'ordre émotionnel si elle était séparée d'eux.

4 The response to this request was contained in a letter dated April 18, 1994 and signed by Immigration Officer M. Caden, stating that a decision had been made that there were insufficient humanitarian and compassionate grounds to warrant processing Ms. Baker's application for permanent residence within Canada. This letter contained no reasons for the decision.

En réponse à cette demande, une lettre datée du 18 avril 1994 et signée par l'agent d'immigration M. Caden a informé M^me^ Baker de la décision qu'il n'y avait pas suffisamment de raisons humanitaires pour justifier de traiter au Canada sa demande de résidence permanente, sans toutefois donner les motifs de la décision.

5 Upon request of the appellant's counsel, she was provided with the notes made by Immigration Officer G. Lorenz, which were used by Officer Caden when making his decision. After a summary

À la demande de l'avocat de l'appelante, les notes de l'agent d'immigration G. Lorenz, que l'agent Caden a utilisées pour rendre sa décision, ont été remises à l'appelante. Après un résumé de of the history of the case, Lorenz's notes read as follows:

PC is unemployed — on Welfare. No income shown — no assets. Has four Cdn.-born children — four other children in Jamaica — HAS A TOTAL OF EIGHT CHILDREN

Says only two children are in her "direct custody". (No info on who has ghe [*sic*] other two). There is nothing for her in Jamaica — hasn't been there in a long time — no longer close to her children there — no jobs there — she has no skills other than as a domestic — children would suffer — can't take them with her and can't leave them with anyone here. Says has suffered from a mental disorder since '81 — is now an outpatient and is improving. If sent back will have a relapse.

Letter from Children's Aid — they say PC has been diagnosed as a paranoid schizophrenic. — children would suffer if returned — Letter of Aug. '93 from psychiatrist from Ont. Govm't. Says PC had post-partum psychosis and had a brief episode of psychosis in Jam. when was 25 yrs. old. Is now an out-patient and is doing relatively well — deportation would be an extremely stressful experience.

Lawyer says PS [*sic*] is sole caregiver and single parent of two Cdn born children. Pc's mental condition would suffer a setback if she is deported etc.

This case is a catastrophy [*sic*]. It is also an indictment of our "system" that the client came as a visitor in Aug. '81, was not ordered deported until Dec. '92 and in APRIL '94 IS STILL HERE!

The PC is a paranoid schizophrenic and on welfare. She has no qualifications other than as a domestic. She has FOUR CHILDREN IN JAMAICA AND ANOTHER FOUR BORN HERE. She will, of course, be a tremendous strain on our social welfare systems for (probably) the rest of her life. There are no H&C factors other than her FOUR CANADIAN-BORN CHILDREN. Do we let her stay because of that? I am of the opinion that Canada can no longer afford this type of generosity. However, because of the circumstances involved, there

l'historique de l'affaire, les notes de M. Lorenz se lisent:

[TRADUCTION] PC est sans emploi — reçoit l'assistance sociale. Aucun revenu connu — pas de biens. A quatre enfants nés au Canada, quatre autres en Jamaïque — HUIT ENFANTS AU TOTAL

Dit que seulement deux enfants sont sous sa garde directe. (Aucun renseignement sur la garde des deux autres). Il n'y a rien qui l'attend en Jamaïque — n'y est pas allée depuis longtemps — n'est plus proche de ses enfants qui s'y trouvent — pas d'emplois — n'a pas d'autre métier que celui de domestique — les enfants souffriraient — elle ne peut pas les emmener avec elle et elle n'a personne ici à qui les confier. Dit qu'elle souffre de troubles mentaux depuis 1981 — elle est actuellement une patiente en consultation externe et son état s'améliore. Si elle est renvoyée là-bas, elle fera une rechute.

Lettre de la Société d'aide à l'enfance — dit que PC souffre d'une schizophrénie paranoïde — les enfants souffriraient, si elle était renvoyée. Lettre d'août 1993 d'un psychiatre du gouvernement de l'Ontario — dit que PC a une psychose post-partum et a eu une brève période de psychose en Jamaïque quand elle avait 25 ans. Elle est maintenant patiente en consultation externe et se porte relativement bien — l'expulsion serait une expérience extrêmement stressante.

L'avocat dit que PC est une mère célibataire et qu'elle est la seule à pouvoir prendre soin de deux de ses enfants nés au Canada. L'état mental de PC se détériorerait si elle devait être déportée etc.

Cette affaire est une catastrophe. C'est aussi une condamnation de notre système: la cliente est arrivée comme visiteur en août 1981, une ordonnance d'expulsion n'a été prise qu'en décembre 1992 et en AVRIL 1994 ELLE EST TOUJOURS ICI!

PC est atteinte de schizophrénie paranoïde et reçoit l'assistance sociale. Elle n'a pas d'autres qualifications que de domestique. Elle a QUATRE ENFANTS EN JAMAÏQUE ET QUATRE AUTRES NÉS ICI. Elle sera, bien entendu, un fardeau excessif pour nos systèmes d'aide sociale (probablement) pour le reste de sa vie. Il n'existe pas d'autres facteurs d'ordre humanitaire que ses QUATRE ENFANTS NÉS AU CANADA. Devons-nous lui permettre de rester pour ça? Je suis d'avis que le Canada ne peut plus se permettre cette sorte de générosité. Toutefois, compte tenu des circonstances, il est possible qu'il y ait une mauvaise presse.

is a potential for adverse publicity. I recommend refusal but you may wish to clear this with someone at Region.

There is also a potential for violence — see charge of "assault with a weapon" [Capitalization in original.]

Je recommande le rejet, mais vous désirerez peut-être obtenir l'approbation de quelqu'un au centre régional.

Violence possible — voir l'accusation d'agression armée. [Majuscules dans l'original.]

6 Following the refusal of her application, Ms. Baker was served, on May 27, 1994, with a direction to report to Pearson Airport on June 17 for removal from Canada. Her deportation has been stayed pending the result of this appeal.

À la suite du rejet de sa demande, Mme Baker a reçu signification, le 27 mai 1994, de l'ordre de se présenter à l'aéroport Pearson le 17 juin pour son renvoi du Canada. Un sursis d'expulsion a été ordonné jusqu'à l'issue du présent pourvoi.

II. Relevant Statutory Provisions and Provisions of International Treaties

II. Les dispositions législatives et des traités internationaux

7 *Immigration Act*, R.S.C., 1985, c. I-2

82.1 (1) An application for judicial review under the *Federal Court Act* with respect to any decision or order made, or any matter arising, under this Act or the rules or regulations thereunder may be commenced only with leave of a judge of the Federal Court — Trial Division.

83. (1) A judgment of the Federal Court — Trial Division on an application for judicial review with respect to any decision or order made, or any matter arising, under this Act or the rules or regulations thereunder may be appealed to the Federal Court of Appeal only if the Federal Court — Trial Division has at the time of rendering judgment certified that a serious question of general importance is involved and has stated that question.

114. . . .

(2) The Governor in Council may, by regulation, authorize the Minister to exempt any person from any regulation made under subsection (1) or otherwise facilitate the admission of any person where the Minister is satisfied that the person should be exempted from that regulation or that the person's admission should be facilitated owing to the existence of compassionate or humanitarian considerations.

Immigration Regulations, 1978, SOR/78-172, as amended by SOR/93-44

2.1 The Minister is hereby authorized to exempt any person from any regulation made under subsection 114(1) of the Act or otherwise facilitate the admission to

Loi sur l'immigration, L.R.C. (1985), ch. I-2

82.1 (1) La présentation d'une demande de contrôle judiciaire aux termes de la *Loi sur la Cour fédérale* ne peut, pour ce qui est des décisions ou ordonnances rendues, des mesures prises ou de toute question soulevée dans le cadre de la présente loi ou de ses textes d'application — règlements ou règles — se faire qu'avec l'autorisation d'un juge de la Section de première instance de la Cour fédérale.

83. (1) Le jugement de la Section de première instance de la Cour fédérale rendu sur une demande de contrôle judiciaire relative à une décision ou ordonnance rendue, une mesure prise ou toute question soulevée dans le cadre de la présente loi ou de ses textes d'application — règlements ou règles — ne peut être porté en appel devant la Cour d'appel fédérale que si la Section de première instance certifie dans son jugement que l'affaire soulève une question grave de portée générale et énonce celle-ci.

114. . . .

(2) Le gouverneur en conseil peut, par règlement, autoriser le ministre à accorder, pour des raisons d'ordre humanitaire, une dispense d'application d'un règlement pris aux termes du paragraphe (1) ou à faciliter l'admission de toute autre manière.

Règlement sur l'immigration de 1978, DORS/78-172, modifié par DORS/93-44

2.1 Le ministre est autorisé à accorder, pour des raisons d'ordre humanitaire, une dispense d'application d'un règlement pris aux termes du paragraphe 114(1) de

Canada of any person where the Minister is satisfied that the person should be exempted from that regulation or that the person's admission should be facilitated owing to the existence of compassionate or humanitarian considerations.

la Loi ou à faciliter l'admission au Canada de toute autre manière.

Convention on the Rights of the Child, Can. T.S. 1992 No. 3

Article 3

1. In all actions concerning children, whether undertaken by public or private social welfare institutions, courts of law, administrative authorities or legislative bodies, the best interests of the child shall be a primary consideration.

2. States Parties undertake to ensure the child such protection and care as is necessary for his or her well-being, taking into account the rights and duties of his or her parents, legal guardians, or other individuals legally responsible for him or her, and, to this end, shall take all appropriate legislative and administrative measures.

Article 9

1. States Parties shall ensure that a child shall not be separated from his or her parents against their will, except when competent authorities subject to judicial review determine, in accordance with applicable law and procedures, that such separation is necessary for the best interests of the child. Such determination may be necessary in a particular case such as one involving abuse or neglect of the child by the parents, or one where the parents are living separately and a decision must be made as to the child's place of residence.

2. In any proceedings pursuant to paragraph 1 of the present article, all interested parties shall be given an opportunity to participate in the proceedings and make their views known.

3. States Parties shall respect the right of the child who is separated from one or both parents to maintain personal relations and direct contact with both parents on a regular basis, except if it is contrary to the child's best interests.

4. Where such separation results from any action initiated by a State Party, such as the detention, imprisonment, exile, deportation or death (including death arising from any cause while the person is in the custody of the State) of one or both parents or of the child, that State Party shall, upon request, provide the parents, the child or, if appropriate, another member of the family

Convention relative aux droits de l'enfant, R.T. Can. 1992 nº 3

Article 3

1. Dans toutes les décisions qui concernent les enfants, qu'elles soient le fait des institutions publiques ou privées de protection sociale, des tribunaux, des autorités administratives ou des organes législatifs, l'intérêt supérieur de l'enfant doit être une considération primordiale.

2. Les États parties s'engagent à assurer à l'enfant la protection et les soins nécessaires à son bien-être, compte tenu des droits et des devoirs de ses parents, de ses tuteurs ou des autres personnes légalement responsables de lui, et ils prennent à cette fin toutes les mesures législatives et administratives appropriées.

Article 9

1. Les États parties veillent à ce que l'enfant ne soit pas séparé de ses parents contre leur gré, à moins que les autorités compétentes ne décident, sous réserve de révision judiciaire et conformément aux lois et procédures applicables, que cette séparation est nécessaire dans l'intérêt supérieur de l'enfant. Une décision en ce sens peut être nécessaire dans certains cas particuliers, par exemple lorsque les parents maltraitent ou négligent l'enfant, ou lorsqu'ils vivent séparément et qu'une décision doit être prise au sujet du lieu de résidence de l'enfant.

2. Dans tous les cas prévus au paragraphe 1 du présent article, toutes les parties intéressées doivent avoir la possibilité de participer aux délibérations et de faire connaître leurs vues.

3. Les États parties respectent le droit de l'enfant séparé de ses deux parents ou de l'un d'eux d'entretenir régulièrement des relations personnelles et des contacts directs avec ses deux parents, sauf si cela est contraire à l'intérêt supérieur de l'enfant.

4. Lorsque la séparation résulte de mesures prises par un État partie, telles que la détention, l'emprisonnement, l'exil, l'expulsion ou la mort (y compris la mort, quelle qu'en soit la cause, survenue en cours de détention) des deux parents ou de l'un d'eux, ou de l'enfant, l'État partie donne sur demande aux parents, à l'enfant ou, s'il y a lieu, à un autre membre de la famille les renseignements

with the essential information concerning the whereabouts of the absent member(s) of the family unless the provision of the information would be detrimental to the well-being of the child. States Parties shall further ensure that the submission of such a request shall of itself entail no adverse consequences for the person(s) concerned.

Article 12

1. States Parties shall assure to the child who is capable of forming his or her own views the right to express those views freely in all matters affecting the child, the views of the child being given due weight in accordance with the age and maturity of the child.

2. For this purpose, the child shall in particular be provided the opportunity to be heard in any judicial and administrative proceedings affecting the child, either directly, or through a representative or an appropriate body, in a manner consistent with the procedural rules of national law.

III. Judgments

A. *Federal Court — Trial Division* (1995), 101 F.T.R. 110

8 Simpson J. delivered oral reasons dismissing the appellant's judicial review application. She held that since there were no reasons given by Officer Caden for his decision, no affidavit was provided, and no reasons were required, she would assume, in the absence of evidence to the contrary, that he acted in good faith and made a decision based on correct principles. She rejected the appellant's argument that the statement in Officer Lorenz's notes that Ms. Baker would be a strain on the welfare system was not supported by the evidence, holding that it was reasonable to conclude from the reports provided that Ms. Baker would not be able to return to work. She held that the language of Officer Lorenz did not raise a reasonable apprehension of bias, and also found that the views expressed in his notes were unimportant, because they were not those of the decision-maker, Officer Caden. She rejected the appellant's argument that the *Convention on the Rights of the Child* mandated that the appellant's interests be given priority in s. 114(2) decisions, holding that the Convention did not apply to this situation, and was not part of domestic law. She also held that the evidence

essentiels sur le lieu où se trouvent le membre ou les membres de la famille, à moins que la divulgation de ces renseignements ne soit préjudiciable au bien-être de l'enfant. Les États parties veillent en outre à ce que la présentation d'une telle demande n'entraîne pas en elle-même de conséquences fâcheuses pour la personne ou les personnes intéressées.

Article 12

1. Les États parties garantissent à l'enfant qui est capable de discernement le droit d'exprimer librement son opinion sur toute question l'intéressant, les opinions de l'enfant étant dûment prises en considération eu égard à son âge et à son degré de maturité.

2. À cette fin, on donnera notamment à l'enfant la possibilité d'être entendu dans toute procédure judiciaire ou administrative l'intéressant, soit directement, soit par l'intermédiaire d'un représentant ou d'un organisme approprié, de façon compatible avec les règles de procédure de la législation nationale.

III. Les jugements

A. *Cour fédérale — Section de première instance* (1995), 101 F.T.R. 110

Le juge Simpson a prononcé à l'audience les motifs rejetant la demande de contrôle judiciaire de l'appelante. Elle a statué que, puisque l'agent Caden n'avait pas motivé sa décision, qu'aucun affidavit n'avait été fourni, et qu'aucun motif n'était requis, elle présumerait, en l'absence de preuve contraire, qu'il avait agi de bonne foi et avait rendu la décision en se fondant sur des principes appropriés. Elle a rejeté l'argument de l'appelante selon lequel l'affirmation dans les notes de l'agent Lorenz que M^{me} Baker serait un fardeau pour le système d'aide sociale n'était pas étayée par la preuve, concluant qu'il était raisonnable de conclure au vu des rapports fournis que M^{me} Baker ne pourrait pas reprendre le travail. Elle a conclu que le langage de l'agent Lorenz ne donnait pas lieu à une crainte raisonnable de partialité, et a également conclu que les opinions exprimées dans ses notes étaient sans importance parce qu'elles n'étaient pas celles du décideur, l'agent Caden. Elle a rejeté l'argument de l'appelante selon lequel la *Convention relative aux droits de l'enfant* commandait que l'intérêt de l'appelante prime dans les décisions fondées sur le par. 114(2), concluant que showed the children were a significant factor in the decision-making process. She rejected the appellant's submission that the Convention gave rise to a legitimate expectation that the children's interests would be a primary consideration in the decision.

la Convention ne s'appliquait pas à cette situation, et ne faisait pas partie du droit interne. Elle a également conclu que la preuve démontrait que les enfants avaient constitué un facteur important dans le processus décisionnel et a rejeté l'argument de l'appelante selon lequel la Convention donnait lieu à une attente légitime que l'intérêt des enfants serait une considération primordiale dans la décision.

Simpson J. certified the following as a "serious question of general importance" under s. 83(1) of the *Immigration Act*: "Given that the Immigration Act does not expressly incorporate the language of Canada's international obligations with respect to the International Convention on the Rights of the Child, must federal immigration authorities treat the best interests of the Canadian child as a primary consideration in assessing an applicant under s. 114(2) of the *Immigration Act*?"

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Le juge Simpson a certifié la question suivante comme «question grave de portée générale» en vertu du par. 83(1) de la *Loi sur l'immigration*: «Vu que la Loi sur l'immigration n'incorpore pas expressément le langage des obligations internationales du Canada en ce qui concerne la Convention internationale relative aux droits de l'enfant, les autorités d'immigration fédérales doivent-elles considérer l'intérêt supérieur de l'enfant né au Canada comme une considération primordiale dans l'examen du cas d'un requérant sous le régime du par. 114(2) de la *Loi sur l'immigration*?»

B. *Federal Court of Appeal*, [1997] 2 F.C. 127

B. *Cour d'appel fédérale*, [1997] 2 C.F. 127

The reasons of the Court of Appeal were delivered by Strayer J.A. He held that pursuant to s. 83(1) of the *Immigration Act*, the appeal was limited to the question certified by Simpson J. He also rejected the appellant's request to challenge the constitutional validity of s. 83(1). Strayer J.A. noted that a treaty cannot have legal effect in Canada unless implemented through domestic legislation, and that the Convention had not been adopted in either federal or provincial legislation. He held that although legislation should be interpreted, where possible, to avoid conflicts with Canada's international obligations, interpreting s. 114(2) to require that the discretion it provides for must be exercised in accordance with the Convention would interfere with the separation of powers between the executive and legislature. He held that such a principle could also alter rights and obligations within the jurisdiction of provincial legislatures. Strayer J.A. also rejected the argument that any articles of the Convention could be interpreted to impose an obligation upon the government to give primacy to the interests of the children in a proceeding such as deportation. He

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Les motifs de la Cour d'appel sont exposés par le juge Strayer. Il déclare que, conformément au par. 83(1) de la *Loi sur l'immigration*, l'appel est limité à la question certifiée par le juge Simpson. Il rejette également la contestation par l'appelante de la constitutionnalité du par. 83(1). Le juge Strayer note qu'un traité ne peut pas avoir d'effet juridique au Canada s'il n'a pas été mis en vigueur par une loi adoptée à cet effet, et que la Convention n'avait pas été adoptée par une loi fédérale ou provinciale. Il conclut que, bien que la loi doive, dans la mesure du possible, être interprétée de façon à ne pas entraîner de conflit avec les obligations internationales du Canada, dire que le par. 114(2) exige que le pouvoir discrétionnaire conféré s'exerce conformément à la Convention enfreindrait la séparation des pouvoirs entre l'exécutif et le législatif. Il conclut qu'un tel principe pourrait également toucher des droits et obligations relevant de la compétence des législatures provinciales. Le juge Strayer rejette également l'argument selon lequel quelque article de la Convention peut s'interpréter de façon à imposer l'obligation au gouvernement d'accorder priorité à l'intérêt des held that the deportation of a parent was not a decision "concerning" children within the meaning of article 3. Finally, Strayer J.A. considered the appellant's argument based on the doctrine of legitimate expectations. He noted that because the doctrine does not create substantive rights, and because a requirement that the best interests of the children be given primacy by a decision-maker under s. 114(2) would be to create a substantive right, the doctrine did not apply.

enfants dans une procédure comme l'expulsion. Il conclut que l'expulsion du père ou de la mère n'est pas une décision «concernant» les enfants au sens de l'article 3. Enfin, le juge Strayer, examinant l'argument de l'appelante fondé sur la doctrine de l'attente légitime, conclut que puisque l'attente légitime ne crée aucun droit matériel et que le fait d'exiger qu'un décideur donne priorité à l'intérêt supérieur des enfants sous le régime du par. 114(2) aurait pour effet de créer un droit matériel, la doctrine ne s'appliquait pas.

IV. Issues

11 Because, in my view, the issues raised can be resolved under the principles of administrative law and statutory interpretation, I find it unnecessary to consider the various *Charter* issues raised by the appellant and the interveners who supported her position. The issues raised by this appeal are therefore as follows:

(1) What is the legal effect of a stated question under s. 83(1) of the *Immigration Act* on the scope of appellate review?

(2) Were the principles of procedural fairness violated in this case?

(i) Were the participatory rights accorded consistent with the duty of procedural fairness?

(ii) Did the failure of Officer Caden to provide his own reasons violate the principles of procedural fairness?

(iii) Was there a reasonable apprehension of bias in the making of this decision?

(3) Was this discretion improperly exercised because of the approach taken to the interests of Ms. Baker's children?

I note that it is the third issue that raises directly the issues contained in the certified question of general importance stated by Simpson J.

IV. Les questions en litige

Comme, à mon avis, l'appel peut être tranché en vertu des principes du droit administratif et de l'interprétation des lois, il n'est pas nécessaire d'examiner les divers moyens fondés sur la *Charte* qui ont été invoqués par l'appelante et les intervenants qui l'ont appuyée. Par conséquent, les questions examinées sont les suivantes:

(1) Quel effet juridique la question énoncée aux termes du par. 83(1) de la *Loi sur l'immigration* a-t-elle sur la portée de l'examen en appel?

(2) Les principes d'équité procédurale ont-ils été enfreints en l'espèce?

(i) Les droits de participation accordés étaient-ils compatibles avec l'obligation d'équité procédurale?

(ii) Le défaut de l'agent Caden d'exposer les motifs de sa décision a-t-il enfreint les principes d'équité procédurale?

(iii) Y avait-il une crainte raisonnable de partialité dans la prise de cette décision?

(3) Le pouvoir discrétionnaire a-t-il été incorrectement exercé en raison de la façon d'aborder l'intérêt des enfants de M^me^ Baker?

Je note que c'est la troisième question qui soulève directement les points mentionnés dans la question certifiée de portée générale énoncée par le juge Simpson.

V. Analysis

A. *Stated Questions Under Section 83(1) of the Immigration Act*

The Court of Appeal held, in accordance with its decision in *Liyanagamage v. Canada (Minister of Citizenship and Immigration)* (1994), 176 N.R. 4, that the requirement, in s. 83(1), that a "serious question of general importance" be certified for an appeal to be permitted restricts an appeal court to addressing the issues raised by the certified question. However, in *Pushpanathan v. Canada (Minister of Citizenship and Immigration)*, [1998] 1 S.C.R. 982, at para. 25, this Court held that s. 83(1) does not require that the Court of Appeal address only the stated question and issues related to it:

> The certification of a "question of general importance" is the trigger by which an appeal is justified. The object of the appeal is still the judgment itself, not merely the certified question.

Rothstein J. noted in *Ramoutar v. Canada (Minister of Employment and Immigration)*, [1993] 3 F.C. 370 (T.D.), that once a question has been certified, all aspects of the appeal may be considered by the Court of Appeal, within its jurisdiction. I agree. The wording of s. 83(1) suggests, and *Pushpanathan* confirms, that if a "question of general importance" has been certified, this allows for an appeal from the judgment of the Trial Division which would otherwise not be permitted, but does not confine the Court of Appeal or this Court to answering the stated question or issues directly related to it. All issues raised by the appeal may therefore be considered here.

B. *The Statutory Scheme and the Nature of the Decision*

Before examining the various grounds for judicial review, it is appropriate to discuss briefly the nature of the decision made under s. 114(2) of the *Immigration Act*, the role of this decision in the statutory scheme, and the guidelines given by the Minister to immigration officers in relation to it.

V. Analyse

A. *Les questions énoncées en vertu du par. 83(1) de la Loi sur l'immigration*

La Cour d'appel a conclu, conformément à son arrêt *Liyanagamage c. Canada (Ministre de la Citoyenneté et de l'Immigration)* (1994), 176 N.R. 4, que le par. 83(1), en exigeant qu'une «question grave de portée générale» soit certifiée pour qu'un appel puisse être autorisé, limite l'appel aux questions soulevées par la question certifiée. Toutefois, dans l'arrêt *Pushpanathan c. Canada (Ministre de la Citoyenneté et de l'Immigration)*, [1998] 1 R.C.S. 982, au par. 25, notre Cour a conclu que le par. 83(1) n'exige pas que la Cour d'appel traite uniquement de la question énoncée et des points qui s'y rapportent: 12

> Sans la certification d'une «question grave de portée générale», l'appel ne serait pas justifié. L'objet de l'appel est bien le jugement lui-même, et non simplement la question certifiée.

Le juge Rothstein dit, dans le jugement *Ramoutar c. Canada (Ministre de l'Emploi et de l'Immigration)*, [1993] 3 C.F. 370 (1re inst.), que lorsqu'une question a été certifiée, la Cour d'appel peut examiner tous les aspects de l'appel qui relèvent de sa compétence. Je suis d'accord. Le libellé du par. 83(1) indique, et l'arrêt *Pushpanathan* le confirme, que la certification d'une «question grave de portée générale» permet un appel du jugement de première instance qui, normalement, ne serait pas autorisé, mais ne limite pas la Cour d'appel ni notre Cour à la question énoncée ou aux points qui s'y rapportent directement. Par conséquent, nous pouvons examiner tous les points soulevés dans le pourvoi.

B. *Le régime législatif et la nature de la décision*

Avant d'examiner les divers moyens invoqués dans la demande de contrôle judiciaire, il est nécessaire d'aborder brièvement la nature de la décision rendue en vertu du par. 114(2) de la *Loi sur l'immigration*, du rôle que joue cette décision dans le régime législatif, et des directives données par le ministre aux agents d'immigration à ce sujet. 13

14 Section 114(2) itself authorizes the Governor in Council to authorize the Minister to exempt a person from a regulation made under the Act, or to facilitate the admission to Canada of any person. The Minister's power to grant an exemption based on humanitarian and compassionate (H & C) considerations arises from s. 2.1 of the *Immigration Regulations*, which I reproduce for convenience:

> The Minister is hereby authorized to exempt any person from any regulation made under subsection 114(1) of the Act or otherwise facilitate the admission to Canada of any person where the Minister is satisfied that the person should be exempted from that regulation or that the person's admission should be facilitated owing to the existence of compassionate or humanitarian considerations.

For the purpose of clarity, I will refer throughout these reasons to decisions made pursuant to the combination of s. 114(2) of the Act and s. 2.1 of the Regulations as "H & C decisions".

15 Applications for permanent residence must, as a general rule, be made from outside Canada, pursuant to s. 9(1) of the Act. One of the exceptions to this is when admission is facilitated owing to the existence of compassionate or humanitarian considerations. In law, pursuant to the Act and the Regulations, an H & C decision is made by the Minister, though in practice, this decision is dealt with in the name of the Minister by immigration officers: see, for example, *Minister of Employment and Immigration v. Jiminez-Perez*, [1984] 2 S.C.R. 565, at p. 569. In addition, while in law, the H & C decision is one that provides for an exemption from regulations or from the Act, in practice, it is one that, in cases like this one, determines whether a person who has been in Canada but does not have status can stay in the country or will be required to leave a place where he or she has become established. It is an important decision that affects in a fundamental manner the future of individuals' lives. In addition, it may also have an important impact on the lives of any Canadian children of the person whose humanitarian and compassionate application is being considered, since they may be separated from one of their parents and/or uprooted from their country of

Le paragraphe 114(2) habilite le gouverneur en conseil à autoriser le ministre à accorder une dispense d'application d'un règlement pris aux termes de la Loi, ou à faciliter l'admission d'une personne au Canada. Le pouvoir du ministre d'accorder une dispense pour des raisons d'ordre humanitaire découle de l'art. 2.1 du *Règlement sur l'immigration*:

> Le ministre est autorisé à accorder, pour des raisons d'ordre humanitaire, une dispense d'application d'un règlement pris aux termes du paragraphe 114(1) de la Loi ou à faciliter l'admission au Canada de toute autre manière.

Pour plus de clarté, je référerai aux décisions rendues conformément à une combinaison du par. 114(2) de la Loi et de l'art. 2.1 du règlement de «décisions d'ordre humanitaire».

Les demandes de résidence permanente doivent normalement être présentées à l'extérieur du Canada, conformément au par. 9(1) de la Loi. L'une des exceptions à cette règle est l'admission fondée sur des raisons d'ordre humanitaire. En droit, conformément à la Loi et au règlement, c'est le ministre qui prend les décisions d'ordre humanitaire, alors qu'en pratique, ces décisions sont prises en son nom par des agents d'immigration: voir, par exemple, *Ministre de l'Emploi et de l'Immigration c. Jiminez-Perez*, [1984] 2 R.C.S. 565, à la p. 569. En outre, même si, en droit, une décision d'ordre humanitaire est une décision qui prévoit une dispense d'application du règlement ou de la Loi, en pratique, il s'agit d'une décision, dans des affaires comme celle dont nous sommes saisis, qui détermine si une personne qui est au Canada, mais qui n'a pas de statut, peut y demeurer ou sera tenue de quitter l'endroit où elle s'est établie. Il s'agit d'une décision importante qui a des conséquences capitales sur l'avenir des personnes visées. Elle peut également avoir des répercussions importantes sur la vie des enfants canadiens de la personne qui a fait la demande fondée sur des raisons d'ordre humanitaire puisqu'ils peuvent être séparés d'un de leurs parents ou déracinés de leur pays de citizenship, where they have settled and have connections.

Immigration officers who make H & C decisions are provided with a set of guidelines, contained in chapter 9 of the *Immigration Manual: Examination and Enforcement*. The guidelines constitute instructions to immigration officers about how to exercise the discretion delegated to them. These guidelines are also available to the public. A number of statements in the guidelines are relevant to Ms. Baker's application. Guideline 9.05 emphasizes that officers have a duty to decide which cases should be given a favourable recommendation, by carefully considering all aspects of the case, using their best judgment and asking themselves what a reasonable person would do in such a situation. It also states that although officers are not expected to "delve into areas which are not presented during examination or interviews, they should attempt to clarify possible humanitarian grounds and public policy considerations even if these are not well articulated".

The guidelines also set out the bases upon which the discretion conferred by s. 114(2) and the Regulations should be exercised. Two different types of criteria that may lead to a positive s. 114(2) decision are outlined — public policy considerations and humanitarian and compassionate grounds. Immigration officers are instructed, under guideline 9.07, to assure themselves, first, whether a public policy consideration is present, and if there is none, whether humanitarian and compassionate circumstances exist. Public policy reasons include marriage to a Canadian resident, the fact that the person has lived in Canada, has become established, and has become an "illegal de facto resident", and the fact that the person may be a long-term holder of employment authorization or has worked as a foreign domestic. Guideline 9.07 states that humanitarian and compassionate grounds will exist if "unusual, undeserved or disproportionate hardship would be caused to the person seeking consideration if he or she had to leave Canada". The guidelines also directly address

citoyenneté, où ils se sont installés et ont des attaches.

16 Les agents d'immigration qui prennent des décisions d'ordre humanitaire reçoivent une série de lignes directrices, figurant au chapitre 9 du *Guide de l'immigration: examen et application de la loi*, qui leur servent d'instructions sur la façon d'exercer le pouvoir discrétionnaire qui leur est délégué. Le public a aussi accès à ces lignes directrices. Dans ces lignes directrices, plusieurs énoncés s'appliquent à la demande de M^{me} Baker. La directive 9.05 met l'accent sur le devoir des agents de décider quelles affaires devraient recevoir une recommandation favorable, en étudiant avec soin les cas sous tous leurs aspects, en faisant preuve de discernement, et en se demandant ce qu'une personne sensée ferait dans une telle situation. Elle dit également que les agents ne doivent pas «tente[r] d'approfondir des questions qui ne sont pas soulevées au cours des examens ou des entrevues. Toutefois, ils doivent essayer d'obtenir des précisions relativement à des raisons possibles d'intérêt public ou d'ordre humanitaire, même si celles-ci ne sont pas clairement formulées».

17 Ces directives définissent également les fondements de l'exercice du pouvoir discrétionnaire conféré par le par. 114(2) et le règlement. Deux types de raisons pouvant mener à une décision favorable sont indiqués — les raisons d'intérêt public et les considérations humanitaires. Conformément à la directive 9.07, les agents d'immigration doivent s'assurer d'abord qu'il n'existe pas de raisons d'intérêt public, et, s'il n'y en a pas, s'il existe des considérations humanitaires. Les raisons d'intérêt public comprennent, notamment, le mariage à un résident du Canada, le fait qu'une personne a vécu au Canada, s'y est établie et est devenue un résident «de fait en situation administrative irrégulière», et le fait que la personne est titulaire d'un permis de travail de longue date ou a travaillé comme travailleur domestique étranger. La directive 9.07 dit qu'il existe des considérations humanitaires lorsque «des difficultés inhabituelles, injustes ou indues seraient causées à la personne sollicitant l'examen de son cas si celle-ci devait quitter le Canada». Les directives traitent expressé-

situations involving family dependency, and emphasize that the requirement that a person leave Canada to apply from abroad may result in hardship for close family members of a Canadian resident, whether parents, children, or others who are close to the claimant, but not related by blood. They note that in such cases, the reasons why the person did not apply from abroad and the existence of family or other support in the person's home country should also be considered.

ment de situations où il existe des liens familiaux de dépendance, et soulignent que l'obligation de quitter le Canada pour présenter une demande de l'étranger peut occasionner des difficultés à certains membres de la famille proche d'un résident canadien, parents, enfants ou autres proches qui n'ont pas de liens de sang avec le demandeur. Elles précisent que dans de tels cas, il faut aussi tenir compte des raisons pour lesquelles la personne n'a pas présenté sa demande à l'étranger et de la présence d'une famille ou d'autres personnes susceptibles de l'aider dans son pays d'origine.

C. *Procedural Fairness*

C. *L'équité procédurale*

18 The first ground upon which the appellant challenges the decision made by Officer Caden is the allegation that she was not accorded procedural fairness. She suggests that the following procedures are required by the duty of fairness when parents have Canadian children and they make an H & C application: an oral interview before the decision-maker, notice to her children and the other parent of that interview, a right for the children and the other parent to make submissions at that interview, and notice to the other parent of the interview and of that person's right to have counsel present. She also alleges that procedural fairness requires the provision of reasons by the decision-maker, Officer Caden, and that the notes of Officer Lorenz give rise to a reasonable apprehension of bias.

Comme premier moyen pour contester la décision de l'agent Caden, l'appelante allègue qu'elle n'a pas bénéficié de l'équité procédurale. L'appelante estime que l'obligation d'agir équitablement exige le respect des procédures suivantes quand des parents ayant des enfants canadiens présentent une demande fondée sur des raisons d'ordre humanitaire: une entrevue orale devant le décideur, un avis de la tenue de cette entrevue aux enfants et à l'autre parent, un droit pour les enfants et l'autre parent de présenter des arguments au cours de cette entrevue, un avis à l'autre parent de la tenue de l'entrevue et du droit de cette personne d'être représentée par un avocat. Elle allègue également que l'équité procédurale exige que le décideur, soit l'agent Caden, motive sa décision, et que les notes de l'agent Lorenz donnent lieu à une crainte raisonnable de partialité.

19 In addressing the fairness issues, I will consider first the principles relevant to the determination of the content of the duty of procedural fairness, and then address Ms. Baker's arguments that she was accorded insufficient participatory rights, that a duty to give reasons existed, and that there was a reasonable apprehension of bias.

En traitant des questions d'équité, j'examinerai d'abord les principes applicables à la détermination de la nature de l'obligation d'équité procédurale, et ensuite les arguments de M^me^ Baker sur l'insuffisance des droits de participation qui lui ont été accordés, sur l'existence d'une obligation de motiver la décision et sur la crainte raisonnable de partialité.

20 Both parties agree that a duty of procedural fairness applies to H & C decisions. The fact that a decision is administrative and affects "the rights, privileges or interests of an individual" is sufficient to trigger the application of the duty of fairness: *Cardinal v. Director of Kent Institution*,

Les deux parties admettent que l'obligation d'équité procédurale s'applique aux décisions d'ordre humanitaire. Le fait qu'une décision soit administrative et touche «les droits, privilèges ou biens d'une personne» suffit pour entraîner l'application de l'obligation d'équité: *Cardinal c.*

[1985] 2 S.C.R. 643, at p. 653. Clearly, the determination of whether an applicant will be exempted from the requirements of the Act falls within this category, and it has been long recognized that the duty of fairness applies to H & C decisions: *Sobrie v. Canada (Minister of Employment and Immigration)* (1987), 3 Imm. L.R. (2d) 81 (F.C.T.D.), at p. 88; *Said v. Canada (Minister of Employment and Immigration)* (1992), 6 Admin. L.R. (2d) 23 (F.C.T.D.); *Shah v. Minister of Employment and Immigration* (1994), 170 N.R. 238 (F.C.A.).

Directeur de l'établissement Kent, [1985] 2 R.C.S. 643, à la p. 653. Il est évident que la décision quant à savoir si un demandeur sera dispensé des exigences prévues par la Loi entre dans cette catégorie, et il est admis depuis longtemps que l'obligation d'équité s'applique aux décisions d'ordre humanitaire: *Sobrie c. Canada (Ministre de l'Emploi et de l'Immigration)* (1987), 3 Imm. L.R. (2d) 81 (C.F. 1re inst.), à la p. 88; *Said c. Canada (Ministre de l'Emploi et de l'Immigration)* (1992), 6 Admin. L.R. (2d) 23 (C.F. 1re inst.); *Shah c. Ministre de l'Emploi et de l'Immigration* (1994), 170 N.R. 238 (C.A.F.).

(1) Factors Affecting the Content of the Duty of Fairness

(1) Les facteurs ayant une incidence sur la nature de l'obligation d'équité

21

The existence of a duty of fairness, however, does not determine what requirements will be applicable in a given set of circumstances. As I wrote in *Knight v. Indian Head School Division No. 19*, [1990] 1 S.C.R. 653, at p. 682, "the concept of procedural fairness is eminently variable and its content is to be decided in the specific context of each case". All of the circumstances must be considered in order to determine the content of the duty of procedural fairness: *Knight*, at pp. 682-83; *Cardinal*, *supra*, at p. 654; *Old St. Boniface Residents Assn. Inc. v. Winnipeg (City)*, [1990] 3 S.C.R. 1170, *per* Sopinka J.

L'existence de l'obligation d'équité, toutefois, ne détermine pas quelles exigences s'appliqueront dans des circonstances données. Comme je l'écrivais dans l'arrêt *Knight c. Indian Head School Division No. 19*, [1990] 1 R.C.S. 653, à la p. 682, «la notion d'équité procédurale est éminemment variable et son contenu est tributaire du contexte particulier de chaque cas». Il faut tenir compte de toutes les circonstances pour décider de la nature de l'obligation d'équité procédurale: *Knight*, aux pp. 682 et 683; *Cardinal*, précité, à la p. 654; *Assoc. des résidents du Vieux St-Boniface Inc. c. Winnipeg (Ville)*, [1990] 3 R.C.S. 1170, le juge Sopinka.

22

Although the duty of fairness is flexible and variable, and depends on an appreciation of the context of the particular statute and the rights affected, it is helpful to review the criteria that should be used in determining what procedural rights the duty of fairness requires in a given set of circumstances. I emphasize that underlying all these factors is the notion that the purpose of the participatory rights contained within the duty of procedural fairness is to ensure that administrative decisions are made using a fair and open procedure, appropriate to the decision being made and its statutory, institutional, and social context, with an opportunity for those affected by the decision to put forward their views and evidence fully and have them considered by the decision-maker.

Bien que l'obligation d'équité soit souple et variable et qu'elle repose sur une appréciation du contexte de la loi particulière et des droits visés, il est utile d'examiner les critères à appliquer pour définir les droits procéduraux requis par l'obligation d'équité dans des circonstances données. Je souligne que l'idée sous-jacente à tous ces facteurs est que les droits de participation faisant partie de l'obligation d'équité procédurale visent à garantir que les décisions administratives sont prises au moyen d'une procédure équitable et ouverte, adaptée au type de décision et à son contexte légal institutionnel et social, comprenant la possibilité donnée aux personnes visées par la décision de présenter leur points de vue complètement ainsi que des éléments de preuve de sorte qu'ils soient considérés par le décideur.

23 Several factors have been recognized in the jurisprudence as relevant to determining what is required by the common law duty of procedural fairness in a given set of circumstances. One important consideration is the nature of the decision being made and the process followed in making it. In *Knight*, *supra*, at p. 683, it was held that "the closeness of the administrative process to the judicial process should indicate how much of those governing principles should be imported into the realm of administrative decision making". The more the process provided for, the function of the tribunal, the nature of the decision-making body, and the determinations that must be made to reach a decision resemble judicial decision making, the more likely it is that procedural protections closer to the trial model will be required by the duty of fairness. See also *Old St. Boniface*, *supra*, at p. 1191; *Russell v. Duke of Norfolk*, [1949] 1 All E.R. 109 (C.A.), at p. 118; *Syndicat des employés de production du Québec et de l'Acadie v. Canada (Canadian Human Rights Commission)*, [1989] 2 S.C.R. 879, at p. 896, *per* Sopinka J.

La jurisprudence reconnaît plusieurs facteurs pertinents en ce qui a trait aux exigences de l'obligation d'équité procédurale en common law dans des circonstances données. Un facteur important est la nature de la décision recherchée et le processus suivi pour y parvenir. Dans l'arrêt *Knight*, précité, à la p. 683, on a conclu que «la mesure dans laquelle le processus administratif se rapproche du processus judiciaire est de nature à indiquer jusqu'à quel point ces principes directeurs devraient s'appliquer dans le domaine de la prise de décisions administratives». Plus le processus prévu, la fonction du tribunal, la nature de l'organisme rendant la décision et la démarche à suivre pour parvenir à la décision ressemblent à une prise de décision judiciaire, plus il est probable que l'obligation d'agir équitablement exigera des protections procédurales proches du modèle du procès. Voir également *Vieux St-Boniface*, précité, à la p. 1191; *Russell c. Duke of Norfolk*, [1949] 1 All E.R. 109 (C.A.), à la p. 118; *Syndicat des employés de production du Québec et de l'Acadie c. Canada (Commission canadienne des droits de la personne)*, [1989] 2 R.C.S. 879, à la p. 896, le juge Sopinka.

24 A second factor is the nature of the statutory scheme and the "terms of the statute pursuant to which the body operates": *Old St. Boniface*, *supra*, at p. 1191. The role of the particular decision within the statutory scheme and other surrounding indications in the statute help determine the content of the duty of fairness owed when a particular administrative decision is made. Greater procedural protections, for example, will be required when no appeal procedure is provided within the statute, or when the decision is determinative of the issue and further requests cannot be submitted: see D. J. M. Brown and J. M. Evans, *Judicial Review of Administrative Action in Canada* (loose-leaf), at pp. 7-66 to 7-67.

Le deuxième facteur est la nature du régime législatif et les «termes de la loi en vertu de laquelle agit l'organisme en question»: *Vieux St-Boniface*, précité, à la p. 1191. Le rôle que joue la décision particulière au sein du régime législatif, et d'autres indications qui s'y rapportent dans la loi, aident à définir la nature de l'obligation d'équité dans le cadre d'une décision administrative précise. Par exemple, des protections procédurales plus importantes seront exigées lorsque la loi ne prévoit aucune procédure d'appel, ou lorsque la décision est déterminante quant à la question en litige et qu'il n'est plus possible de présenter d'autres demandes: voir D. J. M. Brown et J. M. Evans, *Judicial Review of Administrative Action in Canada* (feuilles mobiles), aux pp. 7-66 et 7-67.

25 A third factor in determining the nature and extent of the duty of fairness owed is the importance of the decision to the individual or individuals affected. The more important the decision is to the lives of those affected and the greater its

Le troisième facteur permettant de définir la nature et l'étendue de l'obligation d'équité est l'importance de la décision pour les personnes visées. Plus la décision est importante pour la vie des personnes visées et plus ses répercussions sont impact on that person or those persons, the more stringent the procedural protections that will be mandated. This was expressed, for example, by Dickson J. (as he then was) in *Kane v. Board of Governors of the University of British Columbia*, [1980] 1 S.C.R. 1105, at p. 1113:

A high standard of justice is required when the right to continue in one's profession or employment is at stake. . . . A disciplinary suspension can have grave and permanent consequences upon a professional career.

As Sedley J. (now Sedley L.J.) stated in *R. v. Higher Education Funding Council*, *ex parte Institute of Dental Surgery*, [1994] 1 All E.R. 651 (Q.B.), at p. 667:

In the modern state the decisions of administrative bodies can have a more immediate and profound impact on people's lives than the decisions of courts, and public law has since *Ridge v. Baldwin* [1963] 2 All E.R. 66, [1964] A.C. 40 been alive to that fact. While the judicial character of a function may elevate the practical requirements of fairness above what they would otherwise be, for example by requiring contentious evidence to be given and tested orally, what makes it "judicial" in this sense is principally the nature of the issue it has to determine, not the formal status of the deciding body.

The importance of a decision to the individuals affected, therefore, constitutes a significant factor affecting the content of the duty of procedural fairness.

Fourth, the legitimate expectations of the person challenging the decision may also determine what procedures the duty of fairness requires in given circumstances. Our Court has held that, in Canada, this doctrine is part of the doctrine of fairness or natural justice, and that it does not create substantive rights: *Old St. Boniface*, *supra*, at p. 1204; *Reference re Canada Assistance Plan (B.C.)*, [1991] 2 S.C.R. 525, at p. 557. As applied in Canada, if a legitimate expectation is found to exist, this will affect the content of the duty of fairness owed to the individual or individuals affected by the decision. If the claimant has a legitimate expectation that a certain procedure will be followed, this procedure will be required by the duty

grandes pour ces personnes, plus les protections procédurales requises seront rigoureuses. C'est ce que dit par exemple le juge Dickson (plus tard Juge en chef) dans l'arrêt *Kane c. Conseil d'administration de l'Université de la Colombie-Britannique*, [1980] 1 R.C.S. 1105, à la p. 1113:

Une justice de haute qualité est exigée lorsque le droit d'une personne d'exercer sa profession ou de garder son emploi est en jeu. [. . .] Une suspension de nature disciplinaire peut avoir des conséquences graves et permanentes sur une carrière.

Comme le juge Sedley (maintenant Lord juge Sedley) le dit dans *R. c. Higher Education Funding Council*, *ex parte Institute of Dental Surgery*, [1994] 1 All E.R. 651 (Q.B.), à la p. 667:

[TRADUCTION] Dans le monde moderne, les décisions rendues par des organismes administratifs peuvent avoir un effet plus immédiat et plus important sur la vie des gens que les décisions des tribunaux et le droit public a depuis l'arrêt *Ridge c. Baldwin* [1963] 2 All E.R. 66, [1964] A.C. 40, reconnu ce fait. Bien que le caractère judiciaire d'une fonction puisse élever les exigences pratiques en matière d'équité au-delà de ce qu'elles seraient autrement, par exemple en exigeant que soit présenté et vérifié oralement un élément de preuve contesté, ce qui le rend «judiciaire» dans ce sens est principalement la nature de la question à trancher, et non le statut formel de l'organisme décisionnel.

L'importance d'une décision pour les personnes visées a donc une incidence significative sur la nature de l'obligation d'équité procédurale.

Quatrièmement, les attentes légitimes de la personne qui conteste la décision peuvent également servir à déterminer quelles procédures l'obligation d'équité exige dans des circonstances données. Notre Cour a dit que, au Canada, l'attente légitime fait partie de la doctrine de l'équité ou de la justice naturelle, et qu'elle ne crée pas de droits matériels: *Vieux St-Boniface*, précité, à la p. 1204; *Renvoi relatif au Régime d'assistance publique du Canada (C.-B.)*, [1991] 2 R.C.S. 525, à la p. 557. Au Canada, la reconnaissance qu'une attente légitime existe aura une incidence sur la nature de l'obligation d'équité envers les personnes visées par la décision. Si le demandeur s'attend légitimement à ce qu'une certaine procédure soit suivie, l'obliga- 26 of fairness: *Qi v. Canada (Minister of Citizenship and Immigration)* (1995), 33 Imm. L.R. (2d) 57 (F.C.T.D.); *Mercier-Néron v. Canada (Minister of National Health and Welfare)* (1995), 98 F.T.R. 36; *Bendahmane v. Canada (Minister of Employment and Immigration)*, [1989] 3 F.C. 16 (C.A.). Similarly, if a claimant has a legitimate expectation that a certain result will be reached in his or her case, fairness may require more extensive procedural rights than would otherwise be accorded: D. J. Mullan, *Administrative Law* (3rd ed. 1996), at pp. 214-15; D. Shapiro, "Legitimate Expectation and its Application to Canadian Immigration Law" (1992), 8 *J.L. & Social Pol'y* 282, at p. 297; *Canada (Attorney General) v. Human Rights Tribunal Panel (Canada)* (1994), 76 F.T.R. 1. Nevertheless, the doctrine of legitimate expectations cannot lead to substantive rights outside the procedural domain. This doctrine, as applied in Canada, is based on the principle that the "circumstances" affecting procedural fairness take into account the promises or regular practices of administrative decision-makers, and that it will generally be unfair for them to act in contravention of representations as to procedure, or to backtrack on substantive promises without according significant procedural rights.

tion d'équité exigera cette procédure: *Qi c. Canada (Ministre de la Citoyenneté et de l'Immigration)* (1995), 33 Imm. L.R. (2d) 57 (C.F. 1re inst.); *Mercier-Néron c. Canada (Ministre de la Santé nationale et du Bien-être social)* (1995), 98 F.T.R. 36; *Bendahmane c. Canada (Ministre de l'Emploi et de l'Immigration)*, [1989] 3 C.F. 16 (C.A.). De même, si un demandeur s'attend légitimement à un certain résultat, l'équité peut exiger des droits procéduraux plus étendus que ceux qui seraient autrement accordés: D. J. Mullan, *Administrative Law* (3e éd. 1996), aux pp. 214 et 215; D. Shapiro, «Legitimate Expectation and its Application to Canadian Immigration Law» (1992), 8 *J.L. & Social Pol'y* 282, à la p. 297; *Canada (Procureur général) c. Comité du tribunal des droits de la personne (Canada)* (1994), 76 F.T.R. 1. Néanmoins, la doctrine de l'attente légitime ne peut pas donner naissance à des droits matériels en dehors du domaine de la procédure. Cette doctrine, appliquée au Canada, est fondée sur le principe que les «circonstances» touchant l'équité procédurale comprennent les promesses ou pratiques habituelles des décideurs administratifs, et qu'il serait généralement injuste de leur part d'agir en contravention d'assurances données en matière de procédures, ou de revenir sur des promesses matérielles sans accorder de droits procéduraux importants.

27 Fifth, the analysis of what procedures the duty of fairness requires should also take into account and respect the choices of procedure made by the agency itself, particularly when the statute leaves to the decision-maker the ability to choose its own procedures, or when the agency has an expertise in determining what procedures are appropriate in the circumstances: Brown and Evans, *supra*, at pp. 7-66 to 7-70. While this, of course, is not determinative, important weight must be given to the choice of procedures made by the agency itself and its institutional constraints: *IWA v. Consolidated-Bathurst Packaging Ltd.*, [1990] 1 S.C.R. 282, *per* Gonthier J.

Cinquièmement, l'analyse des procédures requises par l'obligation d'équité devrait également prendre en considération et respecter les choix de procédure que l'organisme fait lui-même, particulièrement quand la loi laisse au décideur la possibilité de choisir ses propres procédures, ou quand l'organisme a une expertise dans le choix des procédures appropriées dans les circonstances: Brown et Evans, *op. cit.*, aux pp. 7-66 à 7-70. Bien que, de toute évidence, cela ne soit pas déterminant, il faut accorder une grande importance au choix de procédures par l'organisme lui-même et à ses contraintes institutionnelles: *IWA c. Consolidated-Bathurst Packaging Ltd.*, [1990] 1 R.C.S. 282, le juge Gonthier.

28 I should note that this list of factors is not exhaustive. These principles all help a court determine whether the procedures that were followed

Je dois mentionner que cette liste de facteurs n'est pas exhaustive. Tous ces principes aident le tribunal à déterminer si les procédures suivies res-

respected the duty of fairness. Other factors may also be important, particularly when considering aspects of the duty of fairness unrelated to participatory rights. The values underlying the duty of procedural fairness relate to the principle that the individual or individuals affected should have the opportunity to present their case fully and fairly, and have decisions affecting their rights, interests, or privileges made using a fair, impartial, and open process, appropriate to the statutory, institutional, and social context of the decision.

pectent l'obligation d'équité. D'autres facteurs peuvent également être importants, notamment dans l'examen des aspects de l'obligation d'agir équitablement non reliés aux droits de participation. Les valeurs qui sous-tendent l'obligation d'équité procédurale relèvent du principe selon lequel les personnes visées doivent avoir la possibilité de présenter entièrement et équitablement leur position, et ont droit à ce que les décisions touchant leurs droits, intérêts ou privilèges soient prises à la suite d'un processus équitable, impartial et ouvert, adapté au contexte légal, institutionnel et social de la décision.

(2) Legitimate Expectations

I turn now to an application of these principles to the circumstances of this case to determine whether the procedures followed respected the duty of procedural fairness. I will first determine whether the duty of procedural fairness that would otherwise be applicable is affected, as the appellant argues, by the existence of a legitimate expectation based upon the text of the articles of the Convention and the fact that Canada has ratified it. In my view, however, the articles of the Convention and their wording did not give rise to a legitimate expectation on the part of Ms. Baker that when the decision on her H & C application was made, specific procedural rights above what would normally be required under the duty of fairness would be accorded, a positive finding would be made, or particular criteria would be applied. This Convention is not, in my view, the equivalent of a government representation about how H & C applications will be decided, nor does it suggest that any rights beyond the participatory rights discussed below will be accorded. Therefore, in this case there is no legitimate expectation affecting the content of the duty of fairness, and the fourth factor outlined above therefore does not affect the analysis. It is unnecessary to decide whether an international instrument ratified by Canada could, in other circumstances, give rise to a legitimate expectation.

(2) L'attente légitime

29

Je passe maintenant à une application de ces principes aux circonstances de l'espèce pour déterminer si les procédures suivies respectaient l'obligation d'équité procédurale. Je déciderai d'abord si l'existence d'une attente légitime fondée sur le texte des articles de la Convention et le fait que le Canada l'ait ratifiée a une incidence, comme l'appelante le soutient, sur l'obligation d'équité procédurale qui serait autrement applicable. À mon avis, les articles de la Convention et leur libellé n'ont pas créé chez M[me] Baker l'attente légitime que sa demande fondée sur des raisons d'ordre humanitaire donne lieu à l'application de droits procéduraux particuliers autres que ceux qui seraient normalement exigés en vertu de l'obligation d'équité, à une conclusion positive, ou à l'utilisation de critères particuliers. Cette convention n'est pas, à mon avis, l'équivalent d'une déclaration gouvernementale sur la façon dont les demandes fondées sur des raisons d'ordre humanitaire doivent être tranchées, elle n'indique pas non plus que des droits autres que les droits de participation dont il est question ci-dessous seront accordés. Par conséquent, dans la présente affaire, il n'existe pas d'attente légitime ayant une incidence sur la nature de l'obligation d'équité et le quatrième facteur identifié plus haut n'affecte donc pas l'analyse. Il n'est pas nécessaire de décider si un instrument international ratifié par le Canada pourrait, dans d'autres circonstances, donner lieu à une attente légitime.

Apotex Inc. v. Canada (Attorney General), [2000] 4 FC 264, 2000 CanLII 17135 (FCA)

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A-922-96

Apotex Inc. (*Appellant*) (*Applicant*)

v.

The Attorney General of Canada, The Minister of National Health and Welfare, Merck & Co., Inc. and **Merck Frosst Canada Inc.** (*Respondents*) (*Respondents*)

and

Eli Lilly Canada Inc., Pharmaceutical Manufacturers Association of Canada and **Canadian Drug Manufacturers Association** (*Interveners*) (*Interveners*)

Indexed as: Apotex Inc.v. Canada (Attorney General) (C.A.)

Court of Appeal, Décary, Sexton and Evans JJ.A.-- Toronto, February 28, 29; Ottawa, May 12, 2000.

Patents -- Validity of Patented Medicines (NOC) Regulations upheld as not ultra vires Patent Act, s. 55.2(4) -- Latter provision to be construed broadly, not limited to those who have availed themselves of benefits conferred by Act, s. 55.2(1) or (2) in connection with particular medicine in dispute -- Within Governor in Council's authority conferred by Act, s. 55.2(4) to provide expressly Regulations apply to submissions made before they came into effect, but not yet decided by Minister.

Practice -- Pleadings -- Mootness, abuse of process -- As Notice of Compliance (NOC) issued to Apotex for norfloxacin, request for order to issue NOC for same drug moot -- Furthermore, as appellant had opportunity to challenge validity of Patented Medicines (NOC) Regulations in earlier prohibition proceedings with respect to same drug, Court could have applied res judicata and issue estoppel to refuse to permit

Apotex to raise it herein -- However, proceeding not dismissed as validity of Regulations remaining live issue (NOC issued on basis of single allegation), and declaration of legal status would still serve useful purpose -- Furthermore, in view of uncertainty about Regulations when litigation started, obvious and continuing interest of Apotex in having validity of Regulations determined, and fact parties had prepared full argument on merits, Motions Judge properly exercised discretion not to dismiss proceeding on this ground without getting to merits.

Administrative law -- Judicial review -- Doctrine of legitimate expectations -- Minister's undertaking to consult Canadian Drug Manufacturers Association before Patented Medicines (Notice of Compliance) Regulations enacted at best personal undertaking of political nature not enforceable by Court; in any event, not binding on decision maker, i.e. Governor in Council.

Construction of statutes -- Retroactivity -- Application of Patented Medicines (NOC) Regulations to new drug submissions in pipeline when 1993 Regulations came into effect did not engage presumption against retroactivity -- No vested right abrogated: in absence of clear legislative indication to contrary, no legal right to have application for statutory benefit determined in accordance with eligibility criteria in place when application made.

Apotex sought a compulsory licence for the generic form of Merck Frosst Canada's patented drug norfloxacin, an antibiotic, under the system in effect before the *Patented Medicines (Notice of Compliance) Regulations* was enacted. In 1993, before Apotex could obtain the authorization to market the generic drug, the compulsory licence system was abolished. In the application for judicial review with which this appeal is concerned, Apotex sought an order directing the Minister of National Health and Welfare to issue a NOC for its version of norfloxacin and declaring that the Regulations were invalid because they were not authorized by subsection 55.2(4) of the *Patent Act*. The validity of the Regulations was also attacked on the ground that they were promulgated without prior consultation, in breach of a promise made by the Minister responsible for the statutory amendments that regulations would not be enacted until there had been consultation with the Canadian Drug Manufacturers Association (CDMA), a trade association representing primarily the interests of generic pharmaceutical manufacturers. This was an appeal from the Trial Division decision dismissing the application for judicial review.

Held, the appeal should be dismissed.

Per Décary J.A. (Sexton J.A. concurring): the reasons for judgment of Evans J.A. were agreed with except with respect to the issue of the breach of the undertaking to consult the CDMA before the enactment of regulations.

The *Patent Act* did not contain provisions stating that regulations proposed to be made pursuant to the Act must be published prior to their coming into force. Regulations made by the Governor in Council under section 55.2 of the Act were therefore subject to the general provisions of the *Statutory Instruments Act* and not required by law to be published prior to their coming into force. And unlike some of the other provisions of the *Patent Act*, section 55.2 imposed no duty to consult.

Assuming that the doctrine of legitimate expectations may apply to the regulation-making power of the Governor in Council, it would not apply in the circumstances of this case because the alleged undertaking is at best a personal undertaking of a political nature that is not enforceable in a court of law. In any event, even it the alleged undertaking could have bound the Minister and be enforceable by a court, it would not, in the circumstances, have bound the Governor in Council, the decision maker. Absent statutory authority or authority expressly delegated to a minister by the Governor in Council, a minister cannot bind the Governor in Council in the exercise of its regulation-making power.

Serious reservations were expressed as to the applicability of the doctrine of legitimate expectations to Cabinet in the exercise of its regulation-making power. In any event, Evans J.A.'s comments on this point were *obiter dicta*. The judiciary should be reluctant to move in and impose procedural restrictions of its own creation on the process leading to the making of regulations by the Governor in Council.

Per Evans J.A.: (1) Given the decision of the Supreme Court of Canada in *Merck Frosst Canada Inc. v. Canada (Minister of National Health and Welfare)*, 1998 CanLII 792 (SCC), [1998] 2 S.C.R. 193, as a result of which Apotex was issued with a NOC for norfloxacin, the issue was moot. However, since the NOC was issued on the basis of a single allegation, the validity of the Regulations remained a live issue, and therefore the declaration of their legal status would still serve a useful purpose. Although Apotex had had an opportunity to challenge the validity of the NOC Regulations in the earlier prohibition proceeding brought by Merck Frosst with respect to norfloxacin, the Motions Judge properly exercised his discretion not to dismiss the proceeding on this ground without getting to the merits in view of the uncertainty about the Regulations when the litigation started, the obvious and continuing interest of Apotex in having the validity of the Regulations determined, and the fact that the parties had prepared full argument on the merits.

(2) Subsection 55.2(4) of the *Patent Act* was not limited to authorizing the making of Regulations that apply to persons who have taken advantage of subsection 55.2(1) or (2) in respect of new drug products that are the subject of prohibition proceeding. If Parliament had intended to limit the scope to the regulation-making power in that way, it would have used more precise, explicit language. The wording in the English and French versions support a broad interpretation. Furthermore, the nature and subjective definition of the purpose for which the power may be exercised supports a broad interpretation: "such regulations as the Governor in Council considers necessary for preventing the infringement of a patent". For these reasons, and in accordance with the general directive of section 12 of the *Interpretation Act* (enactments deemed remedial), subsection 55.2(4) should be construed broadly.

(3) The Regulations, which purport to apply to NOC submissions that had been made, but not decided, when the Regulations came into effect, did not engage the presumption against retroactivity.

No vested right was thereby abrogated: in the absence of clear legislative indication to the contrary, no one has a legal right to have an application for a statutory benefit determined in accordance with the eligibility criteria in place when the application was made. Applicants for statutory rights normally have no more than a hope that the granting authority will render a favourable decision. As the applicant's right herein was neither "accrued" nor "accruing", the paragraph 44(*c*) of the *Interpretation Act* presumption against retroactive operation of the repeal of an enactment did not apply.

(4) The fact that the Minister of Consumer and Corporate Affairs did not consult the CDMA before regulations were enacted under subsection 55.2(4) of the *Patent Act* in spite of an undertaking to do so did not make the Regulations invalid.

It is settled law in Canada that the duty of fairness does not apply to the exercise of powers of a legislative nature, which would include the Regulations herein. However, it does not necessarily follow that subordinate legislation can lawfully be made in breach of a categorical and specific assurance of prior consultation given to an individual by a responsible minister of the Crown in the course of discharging departmental business. Nor does the law so provide.

In *Reference re Canada Assistance Plan (B.C.)*, 1991 CanLII 74 (SCC), [1991] 2 S.C.R. 525, the Supreme Court specifically said that the doctrine of legitimate expectations has no application to the exercise of legislative powers as it would place a fetter on an essential feature of democracy. However, similar considerations do not apply to the exercise of delegated legislative powers which is not subject to the same level of scrutiny as primary legislation that must pass through the full legislative process. Moreover, the procedural rights created by the doctrine of legitimate expectations are always subject to proof that, in particular circumstances, the public interest requires that administrative action be taken promptly without complying with the promised procedures.

The legitimate expectations doctrine is not simply a branch of the duty of fairness, in the sense that it serves the same purposes as the participatory rights conferred by the duty of fairness. Hence, there is no reason to limit its reach to the exercise of statutory powers to which the duty applies. In the absence of binding authority to the contrary, the doctrine of legitimate expectations applies in principle to delegated legislative powers so as to create participatory rights when none would otherwise arise, provided that honouring the expectation would not breach some other legal duty, or unduly delay the enactment of regulations for which there was a demonstrably urgent need.

On the facts of this case, the words used were capable of creating a legitimate expectation that the Minister would consult the CDMA before any regulations made under subsection 55.2(4) came into effect. However an undertaking given by a minister that there will be consultation prior to the enactment of regulations cannot give rise to a legitimate expectation when the Governor in Council, not the minister, has the statutory authority to make the regulations in question. While there was no evidence that the Governor in Council expressly delegated to the Minister of Consumer and Corporate Affairs the authority to impose procedural restrictions on the exercise of the Cabinet's regulation-making power, when, as here, the promise of prior consultation is made by the minister with primary responsibility for developing regulations and bringing them before the Cabinet, it may be open to those to whom the promise was made to seek judicial review to prevent the minister from taking proposed regulations to Cabinet until the promised consultation has occurred.

However, when, as here, the Cabinet has already approved the regulations, their validity cannot be impugned because they were enacted in the absence of the consultation that the minister promised. Given the legal protection afforded by the law to the confidentiality of cabinet proceedings and the narrow grounds on which the courts review the exercise of powers by the Cabinet, it would be impermissible for a court to enquire into the state of knowledge possessed by members of the Cabinet about prior procedural assurances given by a minister in order to determine whether otherwise valid regulations were knowingly enacted in breach of a ministerial undertaking.

In any event, the extensive and effective consultation that occurred after 1993, and prior to the amendments of the Regulations in 1998 which ironed out many of the subsequently identified wrinkles, would make it inappropriate to declare invalid the original Regulations as amended.

statutes and regulations judicially considered

Canada Assistance Plan, R.S.C. 1970, c. C-1 , s. 8.

Canada Labour Code, R.S.C., 1985, c. L-2 , s. 159(2) (as enacted by S.C. 1996, c. 12, s. 3).

Canada Shipping Act, R.S.C., 1985, c. S-9 , s. 95(1) (as am. by R.S.C., 1985 (3rd Supp.), c. 6, s. 5).

Canadian Human Rights Act, R.S.C., 1985, c. H-6 , s. 15(4) (as am. by S.C. 1998, c. 9, s. 10).

Civil Air Navigation Services Commercialization Act, S.C. 1996, c. 20, s. 12(2).

Constitution Act, 1867, 30 & 31 Vict., c. 3 (U.K.) (as am. by *Canada Act 1982*, 1982, c. 11 (U.K.), Schedule to the *Constitution Act, 1982*, Item 1) [R.S.C., 1985, Appendix II, No. 5], ss. 11, 12, 13.

Copyright Act, R.S.C., 1985, c. C-42 , s. 66.6(2) (as enacted by R.S.C., 1985 (4th Supp.), c. 10, s. 12).

Hazardous Materials Information Review Act, R.S.C., 1985 (3rd Supp.), c. 24, Part III, s. 48(1).

Hazardous Products Act, R.S.C., 1985, c. H-3 , s. 19 (as am. by R.S.C., 1985 (3rd Supp.), c. 24, s. 1).

Interpretation Act, R.S.C., 1985, c. I-21 , ss. 12, 35 "Governor in Council", 44 (*c*).

Interpretation Act (The), R.S.S. 1978, c. I-11, s. 23(1)(*c*).

Mackenzie Valley Resource Management Act, S.C. 1998, c. 25, ss. 90, 143, 150.

North American Free Trade Agreement Between the Government of Canada, the Government of the United Mexican States and the Government of the United States of America, December 17, 1992, [1994] Can. T.S. No. 2, Art. 1709(10).

Official Languages Act, R.S.C., 1985 (4th Supp.), c. 31, ss. 84, 86.

Patent Act, R.S.C., 1985, c. P-4 , ss. 42 (as am. by R.S.C., 1985 (3rd Supp.), c. 33, s. 16), 55.2 (as enacted by S.C. 1993, c. 2, s. 4), 101(2) (as enacted *idem*, s. 7).

Patent Act Amendment Act, 1992, S.C. 1993, c. 2, ss. 4, 7, 11(1), 12(1).

Patented Medicines (Notice of Compliance) Regulations, SOR/93-133 , ss. 2, 5 (1) (as am. by SOR/98-166 , s. 4), 6(1) (as am. *idem*, s. 5), (5) (as enacted, *idem*), 7(1) (as am. *idem*, s. 6).

Regulations Act, R.S.Q., c. R-18.1, ss. 8, 10, 12, 13.

Statutory Instruments Act, R.S.C., 1985, c. S-22.

cases judicially considered

applied:

Pulp, Paper and Woodworkers of Canada, Local 8 et al. v. Canada (Minister of Agriculture) et al. (1994), 174 N.R. 37 (F.C.A.); *Scott v. College of Physicians and Surgeons of Saskatchewan* (1992), 1992 CanLII 2751 (SK CA), 95 D.L.R. (4th) 706; [1993] 1 W.W.R. 533; 100 Sask. R. 291 (C.A.).

considered:

Reference re Canada Assistance Plan (B.C.), 1991 CanLII 74 (SCC), [1991] 2 S.C.R. 525; (1991), 83 D.L.R. (4th) 297; [1991] 6 W.W.R. 1; 58 B.C.L.R. (2d) 1; 127 N.R. 161; *Hutchins v. Canada (National Parole Board)*, 1993 CanLII 2981 (FCA), [1993] 3 F.C. 505; (1993), 16 Admin. L.R. (2d) 236; 83 C.C.C. (3d) 563; 156 N.R. 205 (C.A.); *Apotex Inc. v. Canada (Attorney General)*, 1993 CanLII 3004 (FCA), [1994] 1 F.C. 742; (1993), 18 Admin. L.R. (2d) 122; 51 C.P.R. (3d) 339; 162 N.R. 177 (C.A.); affd 1994 CanLII 47 (SCC), [1994] 3 S.C.R. 1100; (1994), 176 N.R. 1; *Old St. Boniface Residents Assn. Inc. v. Winnipeg (City)*, 1990 CanLII 31 (SCC), [1990] 3 S.C.R. 1170; (1990), 75 D.L.R. (4th) 385; [1991] 2 W.W.R. 145; 2 M.P.L.R. (2d) 217; 69 Man.R. (2d) 134; 46 Admin. L.R. 161; 116 N.R. 46; *R v Secretary of State for Health, ex p US Tobacco International Inc*, [1992] 1 All ER 212 (Q.B.D.).

referred to:

Merck Frosst Canada Inc. v. Canada (Minister of National Health and Welfare), 1998 CanLII 792 (SCC), [1998] 2 S.C.R. 193; (1998), 161 D.L.R. (4th) 47; 80 C.P.R. (3d) 368; *Merck Frosst Canada Inc. v. Canada (Minister of National Health and Welfare)* (1998), 1998 CanLII 7600 (FC), 80 C.P.R. (3d) 110; 144 F.T.R. 299 (F.C.T.D.); affd (1999), 1999 CanLII 7557 (FCA), 86 C.P.R. (3d) 489; 236 N.R. 179 (F.C.A.); *Merck Frosst Canada Inc. v. Canada (Minister of National Health and Welfare)* (1998), 1998 CanLII 8936 (FC), 84 C.P.R. (3d) 492; 160 F.T.R. 161 (F.C.T.D.); *Apotex Inc. v. Canada (Minister of National Health and Welfare)* (1997), 1997 CanLII 6216 (FCA), 153 D.L.R. (4th) 68; 76 C.P.R. (3d) 1; 219 N.R. 151 (F.C.A.); leave to appeal to S.C.C. refused, [1998] 1 S.C.R. viii; *Deprenyl Research Ltd. v. Apotex Inc*. (1994), 55 C.P.R. (3d) 171; 77 F.T.R. 62 (F.C.T.D.); affd (1995), 60 C.P.R. (3d) 501; 180 N.R. 323 (F.C.A.); *Smith Kline and French Laboratories Limited v. Douglas Pharmaceuticals Limited*, [1991] F.S.R. 522 (N.Z.C.A.); *Roche Products, Inc. v. Bolar Pharmaceutical Co. Inc.*, 733 F.2d 858 (Fed. Cir. 1984); *Hoffmann-LaRoche Ltd. v. Canada (Minister of National Health and Welfare)* (1996), 67 C.P.R. (3d) 484; 109 F.T.R. 216 (F.C.T.D.); affd (1996), 70 C.P.R. (3d) 1; 70 C.P.R. (3d) 206; 205 N.R. 360 (F.C.A.); *Director of Public Works v. Ho Po Sang*, [1961] A.C. 901 (P.C.); *Coughlan v. North and East Devon Health Authority*, [1999] E.W.J. No. 3774 (C.A.) (QL); *Lehndorff United Properties (Canada) Ltd. et al. v. Edmonton (City)* (1993), 146 A.R. 37; 1993 CanLII 7201 (AB QB), 14 Alta. L.R. (3d) 67; 18 M.P.L.R. (2d) 146 (Q.B.); affd (1994), 1994 ABCA 276 (CanLII), 157 A.R. 169; 23 Alta. L.R. (3d) 1; 23 M.P.L.R. (2d) 146 (C.A.); leave to appeal to S.C.C. refused, [1995] 2 S.C.R. vii; *Bezaire v. Windsor Roman Catholic Separate*

School Board (1992), 1992 CanLII 7675 (ON SC), 9 O.R. (3d) 737; 94 D.L.R. (4th) 310; 8 Admin. L.R. (2d) 29; 57 O.A.C. 39 (Div. Ct.); *Sunshine Coast Parents for French v. School District No. 46 (Sunshine Coast)* (1990), 1990 CanLII 260 (BC SC), 44 Admin. L.R. 252; 49 B.C.L.R. (2d) 252 (B.C.S.C.); *Regina v. Liverpool Corpn. Ex parte Liverpool Taxi Fleet Operators' Association*, [1972] 2 Q.B. 299 (C.A.); *Council of Civil Service Unions v. Minister for the Civil Service*, [1985] A.C. 374 (H.L.); *R. v. Lord Chancellor's Department, ex parte Law Society*, Crown Office List CO/991/93, June 22, 1993 (Q.B.D.); *R. v. Brent London Borough Council, Ex p Gunning* (1985), 84 L.G.R. 168 (Q.B.D.); *Cardinal et al. v. Director of Kent Institution*, 1985 CanLII 23 (SCC), [1985] 2 S.C.R. 643; (1985), 24 D.L.R. (4th) 44; [1986] 1 W.W.R. 577; 69 B.C.L.R. 255; 16 Admin. L.R. 233; 23 C.C.C. (3d) 118; 49 C.R. (3d) 35; 63 N.R. 353; *Thorne's Hardware Ltd. et al. v. The Queen et al.*, 1983 CanLII 20 (SCC), [1983] 1 S.C.R. 106; (1983), 143 D.L.R. (3d) 577; 46 N.R. 91; *Attorney General of Canada v. Inuit Tapirisat of Canada et al.*, 1980 CanLII 21 (SCC), [1980] 2 S.C.R. 735; (1980), 115 D.L.R. (3d) 1; 33 N.R. 304; *Canadian Assn. of Regulated Importers v. Canada (Attorney General)*, 1994 CanLII 3460 (FCA), [1994] 2 F.C. 247; (1994), 17 Admin. L.R. (2d) 121; 164 N.R. 342 (C.A.); leave to appeal to S.C.C. refused, [1994] 2 S.C.R. vi; *Carpenter Fishing Corp. v. Canada*, 1997 CanLII 6391 (FCA), [1998] 2 F.C. 548; (1997), 155 D.L.R. (4th) 572; 221 N.R. 372 (C.A.); leave to appeal to S.C.C. refused, [1998] 2 S.C.R. vi; *Baker v. Canada (Minister of Citizenship and Immigration)*, 1999 CanLII 699 (SCC), [1999] 2 S.C.R. 817; (1999), 174 D.L.R. (4th) 193; 1 Imm. L.R. (3d) 1; 243 N.R. 22.

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APPEAL from a Trial Division decision (*Apotex Inc. v. Canada (Attorney General)*, 1996 CanLII 11747 (FC), [1997] 1 F.C. 518; (1996), 71 C.P.R. (3d) 166; 123 F.T.R. 161) dismissing an application for judicial review wherein an order was sought directing the Minister of National Health and Welfare to issue a notice of compliance for the drug norfloxacin and for a declaration that the *Patented Medicines (Notice of Compliance) Regulations* are *ultra vires* the authority of the Governor in Council under subsection 55.2(4) of the *Patent Act*. Appeal dismissed.

appearances:

H. B. Radomski and *David M. Scrimger* for appellant.

Frederick B. Woyiwada for defendant Attorney General of Canada.

W. H. Richardson and *Caroline Zayid* for defendant Merck & Co. Inc.

Anthony G. Creber for defendants Eli Lilly Canada Inc. and Pharmaceutical Manufacturers Association of Canada.

Ronald G. Slaght and *Timothy H. Gilbert* for intervener Canadian Drug Manufacturers Association.

solicitors of record:

Goodman Phillips & Vineberg, Toronto, for appellant.

Deputy Attorney General of Canada for defendant Attorney General of Canada.

McCarthy Tétrault, Toronto, for defendant Merck & Co. Inc.

Gowling, Strathy & Henderson, Ottawa, for defendants Eli Lilly Canada Inc. and Pharmaceutical Manufacturers Association of Canada.

Lenzcner Slaght Royce Smith Griffin, Toronto, for intervener Canadian Drug Manufacturers Association.

The following are the reasons for judgment rendered in English by

[1]Décary J.A.: The facts and the issues have been described by my brother Evans and there is no need repeating them here. Like him, I have reached the conclusion that the appeal should be dismissed. I adopt his reasons with respect to the first three issues he has identified. I disagree, however, with his reasoning with regards to the fourth issue. The fourth issue is stated as follows:

Issue 4: Are the Regulations invalid because they were made in breach of an undertaking by the Minister of Consumer and Corporate Affairs to the Canadian Drug Manufacturers Association that it would be consulted before regulations were enacted under subsection 55.2(4)?

[2]I will preface my analysis with a few words about the statutory context.

[3]The *Patent Act*[1] (the Act), unlike many other statutes,[2] does not contain provisions stating that regulations proposed to be made pursuant to the Act must be published prior to their coming into force. Regulations made by the Governor in Council under section 55.2 [as enacted by S.C. 1993, c. 2, s. 4] of the Act are therefore subject to the general provisions of the *Statutory Instruments Act*.[3] They are not required by law to be published prior to their coming into force.

[4]The *Patent Act*, like many other statutes,[4] contains provisions requiring prior consultation before certain regulations are adopted. Subsection 101(2) [as enacted by S.C. 1993, c. 2, s. 7] provides that certain regulations pertaining to the pricing of a medicine can only be made by the Governor in Council

101. . . .

(2) . . . on the recommendation of the Minister, made after the Minister has consulted with the provincial ministers of the Crown responsible for health and with such representatives of consumer groups and representatives of the pharmaceutical industry as the Minister considers appropriate.

Parliament has therefore clearly imposed on a minister of the Crown, acting on behalf of the Governor in Council, a statutory duty to consult with certain persons in certain circumstances. No such duty is imposed under section 55.2 of the Act.

[5]Some statutes, such as the *Official Languages Act*, require both prior consultation with respect to proposed regulations (section 84) and prior publication of the proposed regulations once the consultation has been done (section 86).

[6]In other jurisdictions, such as in the province of Quebec, a statute sets out the general rule that every proposed regulation shall be pre-published "with a notice stating, in particular, the period within which no proposed regulation may be made or submitted for approval but within which interested persons may transmit their comments to a person designated in the notice".[5] In the Quebec statute, provision is made for the making of regulations without pre-publication in special circumstances such as when the situation is urgent (section 12), in which case the reason justifying the absence of prior publication must be published with the regulation (section 13).

[7]All this to say that Parliament has already turned its mind to the need for pre-consultation and pre-publication and that courts should examine each given case both in light of the statute at issue and in light of the general statutory framework.

[8]Turning now to my analysis, I would summarize as follows the conclusions I have reached:

(1) Assuming, for the sake of discussion, that the doctrine of legitimate expectations may apply to the regulation-making power of the Governor in Council, it would not apply in the circumstances of this case:

(a) because the alleged undertaking is at best a personal undertaking of a political nature that is not enforceable in a court of law

(b) in any event, it is not an undertaking that binds the decision maker, i.e. the Governor in Council.

(2) My brother Evans having found that the alleged undertaking did not in the circumstances bind the Governor in Council, his comments on the application of the doctrine of legitimate expectations to the regulation-making power of the Governor in Council are *obiter dicta* with respect to which I need only say that I have serious reservations.

1(a) The alleged undertaking is at best a personal undertaking of a political nature that is not enforceable in a court of law

[9]The alleged undertaking was made on February 5, 1993 by the then recently appointed Minister of Consumer and Corporate Affairs, Mr. Pierre A. Vincent. The six-page letter addressed to Mr. Kay, the president of the Canadian Drug Manufacturers Association (the Association) begins as follows:[6]

Dear Mr. Kay:

On behalf of my predecessor, the Honourable Pierre Blais, I acknowledge receipt of your letters of November 16, 1992 and December 3, 1992, concerning Bill C-91. The office of the President of the Privy Council, the Minister of National Defence and the Leader of the House of Commons, have also written to us on your behalf.

I would like to reply to the questions and observations that you raise in these letters:

[10]The Minister then goes on to address seven issues that had been raised by Mr. Kay. His comments on the last issue (issue No. 7), and his concluding words, are as follows:[7]

7. "Patentees do not need the additional remedy of (*sic*) that will be conferred on them if the government proceeds to condition the regulatory approval of generic medicines on the patent status of their innovative counterparts".

Finally, you have objected to an amendment to Bill C-91 giving the Governor in Council authority to prescribe regulations preventing applicants, who use an innovator's patent to obtain regulatory approval to sell their products, from obtaining such approval when an innovative competitor holds a valid patent pertaining to the item. You suggest that a patentee's right to pursue patent infringement actions in the courts is sufficient as innovators are entitled to pursue interlocutory relief and to be compensated in damages if an injunction is not granted and it turns out that there was infringement. You further suggest that regulations under this amendment will serve to keep generic competitors off the market when any allegation of patent infringement is made.

I agree that, as a general rule, judicial remedies are sufficient to address patent infringement. However, the Government, in allowing generic competitors to make use of an innovator's patent to obtain regulatory approval, will remove a patent right that would have otherwise been available to a patentee to prevent a generic competitor from undertaking such activities. The amendment to which you refer must be read in this context. It is designed to enable the Government to mitigate any harm flowing from its decision to allow these activities that would otherwise constitute patent infringement.

Subsection 55.2(1) will ensure that a generic competitor is in a position to market its product immediately after the expiry of any relevant patents. It is not the Government's intention to keep a generic competitor off the market unless there is a valid patent that will be infringed by sale of the generic product. Any regulations drafted pursuant to the newly added subsection 55.2(4) will reflect this intention. Rest assured that you will be consulted before any such regulations are established.

I appreciate your bringing your views to our attention.

Yours sincerely,

Pierre A. Vincent

cc. The Honourable Kim Campbell, P.C., Q.C., M.P.

Minister of National Defence
and Minister of Veterans Affairs
The Right Honourable Joe Clark, P.C., M.P.
President of the Queen's Privy Council
or Canada and Minister Responsible for
Constitutional Affairs
The Honourable Harvie Andre, P.C., M.P.
Government House Leader and Minister of State
to Assist the Prime Minister and Minister
Responsible for the Canada Post

[Emphasis added.]

[11]In my respectful view, the alleged undertaking, underlined *supra*, is nothing more in its full context than a brief assurance made in passing by a minister wearing his political hat. One would expect a true undertaking by a minister of the Crown to be salient, to include some specifics as to the form and timetable of the consultation and to be given to all interested persons in some official form. I find nothing of the sort in these casual words found at the end of the last paragraph of a lengthy letter. The words used by the Minister may, in retrospect, have been imprudent but the Association was naive if it believed that such a comment would be enforceable against the Minister in a court of law.

[12]Furthermore, I am not so sure that the Association was that naive. Subsequent events tend, to the contrary, to confirm that the "undertaking argument" was a mere afterthought.

[13]Neither the originating notice of motion dated October 14, 1993 by Apotex Inc. (Apotex), a member of the Association whose president in an affidavit filed in support of the motion describes himself as acting on behalf of the Association, nor the application for leave to intervene filed in July 21, 1994 by the Association refer to the February 5, 1993 letter containing the alleged undertaking by the Minister.

[14]It further appears from the proceedings and affidavits filed in the Trial Division that the argument originally raised by Apotex and by the Association was with respect to the lack of consultation, not with respect to the breaking of a ministerial undertaking. It was only at the hearing before Mr. Justice MacKay, in 1996, that reference was made to the alleged undertaking of the Minister.[8]

[15]Had the alleged undertaking contained in the February 5, 1993 letter the importance the Association now claims it has, one would have expected the Association to raise it much earlier in the process.

[16]The short answer, therefore, to the Association's submissions is that the alleged undertaking is not, and was never perceived by the Association to be, an undertaking enforceable in a court of law.

1(b) The alleged undertaking is not an undertaking that binds the decision maker, i.e. the Governor in Council

[17]In any event, even if the alleged undertaking was such as to bind the Minister and be enforceable in a court of law, it would not, in the circumstances, have bound the Governor in Council who is, after all, the decision maker.

[18]A minister can make an undertaking having some legal consequences only with respect to a decision which is his, and his alone to make.[9] Absent statutory authority such as that found in subsection 101(2) of the Act or, arguably, absent authority expressly delegated to a minister by the Governor in Council, a minister cannot bind the Governor in Council in the exercise of its regulation-making power. It may be useful to recall that the Governor in Council, as defined by section 35 of the *Interpretation Act*,[10] is "the Governor General of Canada acting by and with the advice of [. . .] the Queen's Privy Council for Canada", an obvious reference to sections 11, 12 and 13 of the *Constitution Act, 1867*.[11]

[19]Given the absence of evidence that the Governor in Council expressly delegated to the Minister "the authority to impose procedural restrictions on the exercise of the Cabinet's regulation-making power", to use the words of my brother Evans at paragraph 133 of his reasons, it follows, in my respectful view, that even if the alleged undertaking by the Minister were found to attract judicial attention, it could not be invoked in the case at bar against the Governor in Council.

[20]The ultimate finding made by my colleague, that the Minister did not bind the Cabinet in the circumstances, makes his intermediate finding with respect to the application of the doctrine of legitimate expectations *obiter dictum*.

(2) *Obiter dicta*

[21]While I would not normally feel the need to comment on what has ended up being *obiter*, the issue has been so throughly canvassed by my colleague that I must at least state that I have serious reservations as to the applicability of the doctrine of legitimate expectations to Cabinet in the exercise of its regulation-making power and that I would have been inclined to reach the same conclusion as that reached by Mr. Justice MacKay in the Trial Division.

[22]As I have shown earlier, the need for prior consultation and for prior publication is something that has not escaped Parliament's attention. Some may be of the view that what is now an exception in federal statutes should be raised to the status of a legal requirement applicable to all regulations, but that decision should in my opinion rest with Parliament. I would be reluctant to have the judiciary move in and impose procedural restrictions of its own creation on the process leading to the making of regulations by the Governor in Council.

[23]When courts enter the realm of general public policy and are asked as in this case to hold Cabinet to an undertaking such that its discretion to make regulations would be fettered, they should be reminded of the comments made by Sopinka J. in *Reference*

re Canada Assistance Plan (B.C.),[12] on the application of the doctrine of legitimate expectations to the exercise of legislative powers.

[24]I appreciate that Sopinka J. was not dealing in that case with regulations made by the Governor in Council, but it seems to me that it would also be an extraordinary remedy to strike down regulations made by the Governor in Council solely because of the failure of a minister of the Crown to fulfill a promise of consultation given on behalf of Cabinet. I need not, however, reach a firm conclusion as the issue, in my view, does not arise in this case.

[25]I note that in all the decisions relied upon by my colleague the regulations at issue were made either by a minister in his capacity as a minister, by a municipal authority or by a school board. No precedent was cited that related to regulations made by the Governor in Council.

[26]In the end, I would dismiss the appeal with costs in favour of the Attorney General of Canada and Merck Frosst Canada Inc. and against Apotex Inc. and the Canadian Drug Manufacturers Association.

Sexton J.A.: I agree.

* * *

The following are the reasons for judgment rendered in English by

Evans J.A.:

A. INTRODUCTION

[27]In this appeal Apotex Inc. maintains that the learned Motions Judge erred in law when he dismissed Apotex' contention that the *Patented Medicines (Notice of Compliance) Regulations*, SOR/93-133 were invalid because they were not authorized by subsection 55.2(4) of the *Patent Act*, R.S.C., 1985, c. P-4, as amended by the *Patent Act Amendment Act, 1992*, S.C. 1993, c. 2, section 4.

[28]These Regulations are an important part of the major reform of patent law as it affects pharmaceutical products that came into effect in 1993. For the first time the law linked the protection of the rights of patent holders to the system of regulatory approval for new drugs by the Minister. The Regulations thus handed to the "brand-name" companies an important new weapon in their battles with generic drug manufacturers.

[29]Previously, regulatory approval was issued in the form of a Notice of Compliance [NOC] as soon as the Minister of National Health and Welfare was satisfied that a new drug was safe and effective. However, the 1993 Regulations enabled a "brand-name" company that held a patent which might be infringed by a new generic drug to institute proceedings to prohibit the Minister from issuing an NOC for the new drug during the life of the patent. Meanwhile, from the date that a company applies for an order of prohibition the Regulations impose an automatic stay of 30 months (reduced to 24 months in 1998 [SOR/98-166]) restraining the Minister from issuing an NOC in

respect of the generic drug pending the determination of the judicial review proceeding.

[30]In view of the courts' reluctance to grant interlocutory injunctions in patent infringement actions, it is not surprising that this statutory scheme has been described as "a draconian regime": *Merck Frosst Canada Inc. v. Canada (Minister of National Health and Welfare)*, 1998 CanLII 792 (SCC), [1998] 2 S.C.R. 193, at page 214.

[31]In the application for judicial review with which this appeal is concerned Apotex seeks an order directing the Minister of National Health and Welfare to issue an NOC for its version of norfloxacin, an antibiotic, and declaring that the Regulations are invalid. Apotex maintains that, properly construed, subsection 55.2(4) of the *Patent Act* authorizes the making of regulations that link patent protection and regulatory approval in a significantly narrower range of situations than those currently included in the Regulations.

[32]The validity of the Regulations is also attacked on the ground that they were promulgated without prior consultation, in breach of a promise made by the Minister responsible for the statutory amendments that regulations would not be enacted until there had been consultation with the Canadian Drug Manufacturers Association, a trade association representing primarily the interests of generic pharmaceutical manufacturers.

B. THE LEGISLATIVE FRAMEWORK

[33]Although the statutory scheme from which this litigation arises is complex, it is only necessary to set out here those provisions that are of most direct relevance to the issues in dispute in this appeal.

Patent Act, R.S.C., 1985, c. P-4 [sections 42 (as am. by R.S.C., 1985 (3rd Supp), c. 33, s. 16), 55.2 (as enacted by S.C. 1993, c. 2, s. 4)].

42. Every patent granted under this Act . . . shall, subject to this Act, grant to the patentee and the patentee's legal representatives for the term of the patent, from the granting of the patent, the exclusive right, privilege and liberty of making, constructing and using the invention and selling it to others to be used, . . .

. . .

55.2 (1) It is not an infringement of a patent for any person to make, construct, use or sell the patented invention solely for uses reasonably related to the development and submission of information required under any law of Canada, a province or a country other than Canada that regulates the manufacture, construction, use or sale of any product.

(2) It is not an infringement of a patent for any person who makes, constructs, uses or sells a patented invention in accordance with subsection (1) to make, construct or use the invention, during the applicable period provided for by the regulations, for the manufacture and storage of articles intended for sale after the date on which the term of the patent expires.

(3) The Governor in Council may make regulations for the purposes of subsection (2), but any period provided for by the regulations must terminate immediately preceding the date on which the term of the patent expires.

(4) The Governor in Council may make such regulations as the Governor in Council considers necessary for preventing the infringement of a patent by any person who makes, constructs, uses or sells a patented invention in accordance with subsection (1) or (2) including, without limiting the generality of the foregoing, regulations

. . .

(*e*) generally governing the issue of a notice, certificate, permit or other document referred to in paragraph (*a*) in circumstances where the issue of that notice, certificate, permit or other document might result directly or indirectly in the infringement of a patent.

(5) In the event of any inconsistency or conflict between

(*a*) this section or any regulations made under this section, and

(*b*) any Act of Parliament or any regulations made thereunder,

this section or the regulations made under this section shall prevail to the extent of the inconsistency or conflict.

Patented Medicines (Notice of Compliance) Regulations, SOR/93-133 [sections 5(1) (as am. by SOR/98-166 , s. 4), 6(1) (as am. *idem*, s. 5), (5) (as enacted *idem*), 7(1) (as am. *idem*, s. 6)].

5. (1) Where a person files or has filed a submission for a notice of compliance in respect of a drug and wishes to compare that drug with, or make reference to, another drug that has been marketed in Canada pursuant to a notice of compliance issued to a first person and in respect of which a patent list has been submitted, the person shall, in the submission, with respect to each patent on the register in respect of the other drug,

(*a*) state that the person accepts that the notice of compliance will not issue until the patent expires; or

(*b*) allege that

(i) the statement made by the first person pursuant to paragraph 4(2)(*c*) is false,

(ii) the patent has expired,

(iii) the patent is not valid, or

(iv) no claim for the medicine itself and no claim for the use of the medicine would be infringed by the making, constructing, using or selling by that person of the drug for which the submission for the notice of compliance is filed.

. . .

6. (1) A first person may, within 45 days after being served with a notice of an allegation pursuant to paragraph 5(3)(*b*) or (*c*), apply to a court for an order prohibiting the Minister from issuing a notice of compliance until after the expiration of a patent that is the subject of the allegation.

. . .

(5) In a proceeding in respect of an application under subsection (1), the court may, on the motion of a second person, dismiss the application

(*a*) if the court is satisfied that the patents at issue are not eligible for inclusion on the register or are irrelevant to the dosage form, strength and route of administration of the drug for which the second person has filed a submission for a notice of compliance; or

(*b*) on the ground that the application is redundant, scandalous, frivolous or vexatious or is otherwise an abuse of process.

. . .

7. (1) The Minister shall not issue a notice of compliance to a second person before the latest of

. . .

(*e*) subject to subsections (2), (3) and (4), the expiration of 24 months after the receipt of proof of the making of any application under subsection 6(1), and

[34]While not immediately germane to the particular issues raised here, it is important to note that section 55.2 and the implementing Regulations were, in a sense, ancillary to the principal reform made to the *Patent Act* by the *Patent Act Amendment Act, 1992*. This was the abolition of the compulsory licence under which, subject to the payment of a royalty, generic drug manufacturers had been able to market in Canada a competing drug that infringed another's patent.

[35]The effect of the 1992 Act was thus to restore the rights of those holding patents in pharmaceutical products to their position before the introduction of compulsory licensing in 1923 and to bring them back into the mainstream of patent law as it applies to other inventions. Compulsory licences were abolished in Canada in order to comply with Article 1709(10) of the North American Free Trade Agreement [*North American Free Trade Agreement Between the Government of Canada, the Government of the United Mexican States and the Government of the United States of America*, December 17, 1992, [1994] Can. T.S. No. 2].

[36]However, in order to ensure that a generic company is in a position to have its infringing drug on the market the moment that the patent on the brand-name expires, subsections 55.2(1) and (2) authorize activities that would otherwise constitute an infringement of the patent. Subsection (1) permits use of the patented invention by a "second person" to demonstrate in its new drug submission for an NOC that its drug is equivalent to the patented medicine. Subsection (2) allows a "second person" to stockpile its otherwise infringing product for sale immediately after the expiry of the patent.

[37]Although not relevant to the disposition of this appeal, I note that in a recent ruling the World Trade Organisation has upheld the "regulatory work-up" exemption in subsection (1), but not the "stockpiling" exemption in subsection (2): *Canada-Patent Protection of Pharmaceutical Products* (Complaint by the European Communities) (2000) W.T.O. Doc. WT/DS114/R (Panel Report).

[38]Subsection 55.2(4) is something of a *quid pro quo* for the concessions contained in subsections (1) and (2), in the sense that it authorizes the Governor in Council to make regulations to protect patent holders against competition from infringing pharmaceutical products before the patent expires by linking patent rights to the issue of an NOC.

[39]Before the Motions Judge, whose decision is reported as *Apotex v. Canada (Attorney General)*, 1996 CanLII 11747 (FC), [1997] 1 F.C. 518 (T.D.), Apotex relied on several grounds for alleging that the Regulations were invalid. At the hearing of the appeal, however, the issues were reduced to four, and it is to these that I now turn.

C. ISSUES AND ANALYSIS

Issue 1: Should the appeal be dismissed for mootness or abuse of process?

[40]The respondents argued as a preliminary point that the appeal should be dismissed as moot because, as a result of a decision by the Supreme Court of Canada in favour of Apotex (*Merck Frosst Canada Inc. v. Canada (Minister of National Health and Welfare*), 1998 CanLII 792 (SCC), [1998] 2 S.C.R. 193), the Minister issued it with an NOC for norfloxacin. Accordingly, the request for an order directing the Minister to issue an NOC would seem redundant. Moreover, since the attack on the validity of the Regulations provided the basis for the order sought to direct the Minister to issue the NOC, the request for declaratory relief, too, had been overtaken by events. Further, it was argued, it was not appropriate to consider aspects of the validity of the Regulations beyond those raised by the facts of this case.

[41]The decision of the Trial Division under appeal in the instant case was rendered before the litigation referred to above had been decided by the Supreme Court of Canada. Counsel for Apotex conceded, in effect, that the request for an order directing the Minister to issue an NOC was now moot. However, the validity of the Regulations remains a live issue, and therefore a declaration of their legal status would still serve a useful purpose. As a major generic drug manufacturer and marketer, Apotex has an interest in the validity of the Regulations that is not confined to this particular case.

[42]In addition, while Apotex had indeed secured an NOC authorizing it to market norfloxacin, this regulatory approval only applies to the particular allegation on which Apotex had successfully answered the prohibition proceeding brought by Merck Frosst. This was that Apotex was not infringing the norfloxacin patent, of which Merck Frosst was an exclusive sub-licensee, because Apotex had purchased norfloxacin in bulk from a supplier who had manufactured it under a compulsory licence from Merck Frosst.

[43]However, when Apotex has exhausted this source it will need another NOC to permit it to market norfloxacin, and battle is likely to be rejoined on whether there is

another ground on which Apotex may successfully allege that it is not infringing Merck Frosst's norfloxacin patent. Indeed, this Court has already upheld a decision of a Trial Division judge who concluded that an allegation of a non-infringing process for producing norfloxacin was unfounded because the process relied on was not substantially different from Merck Frosst's: *Merck Frosst Canada Inc. v. Canada (Minister of National Health and Welfare*) (1998), 1998 CanLII 7600 (FC), 80 C.P.R. (3d) 110 (F.C.T.D.); affd (1999), 1999 CanLII 7557 (FCA), 86 C.P.R. (3d) 489 (F.C.A.). At least one other decision respecting an allegation of a different non-infringing process for manufacturing norfloxacin is apparently on its way to this Court: *Merck Frosst Canada Inc. v. Canada (Minister of National Health and Welfare*) (1998), 1998 CanLII 8936 (FC), 84 C.P.R. (3d) 492 (F.C.T.D.).

[44]Despite the costs, both public and private, inevitably associated with proceedings instituted *seriatim*, it is settled law in this Court that a "second person" may make a series of distinct allegations of non-infringement and thereby force the patent holder to institute a new prohibition proceeding to counter each one: *Apotex Inc. v. Canada (Minister of National Health and Welfare)* (1997), 1997 CanLII 6216 (FCA), 153 D.L.R. (4th) 68 (F.C.A.); leave to appeal refused, [1998] 1 S.C.R. viii. In order to prevent abuse of the process of the Court, this should only be permitted when the subsequent allegation is based on new facts, such as the later discovery of another process for making the medicine that does not infringe the patent.

[45]The Motions Judge considered a different abuse of process argument. This was to the effect that this proceeding was an abuse of the process of the Court because Apotex had had an opportunity to challenge the validity of the NOC Regulations in the earlier prohibition proceeding brought by Merck Frosst with respect to norfloxacin, in which Apotex eventually succeeded in the Supreme Court of Canada: see *Merck Frosst Canada Inc. v. Canada (Minister of National Heath and Welfare), supra*.

[46]The learned Motions Judge was of the view that Apotex could have raised the validity of the Regulations in that proceeding and that, since *res judicata* and issue estoppel apply in principle to prohibition proceedings brought under the NOC Regulations, the Court could refuse to permit Apotex to raise it in the present proceeding. However, in view of the uncertainty about the Regulations when the litigation was started, the obvious and continuing interest of Apotex in having the validity of the Regulations determined, and the fact that the parties had prepared full argument on the merits, the Motions Judge exercised his discretion not to dismiss the proceeding on this ground without getting to the merits.

[47]I am not persuaded that the Motions Judge erred in the exercise of his discretion to hear and determine the application for judicial review in so far as it seeks a declaration that the Regulations are *ultra vires*, despite Apotex' failure to challenge the validity of the Regulations in the previous prohibition proceedings dealing with the same medicine.

[48]For reasons similar to those given by the Motions Judge on the abuse of process point, I would not dismiss the request for a declaration of invalidity as moot. However, this does not necessarily mean that the Court will be prepared to determine

the validity of the Regulations in the abstract, rather than on the basis of the facts of this case.

Issue 2: Does subsection 55.2(4) only authorize the making of regulations that apply to a person who has taken advantage of subsection 55.2(1) or (2) in respect of the new drug product that is the subject of the prohibition proceeding?

[49]Apotex made its new drug submission (NDS) for norfloxacin in 1989, well before the statutory abolition of compulsory licences by the 1992 Act and the statutory linkage of patent protection with the issue of NOCs. It contended that its NDS could not validly be brought within the scope of the Regulations. It is true that subsection 5 (1) [prior to the 1998 amendment] of the Regulations states that they apply to "a person files or, before the coming into force of these Regulations, has filed a submission for a notice of compliance" [emphasis added]. However, in the submission of Apotex, Parliament did not authorize this.

[50]Apotex argues that the underlined words in subsection 5(1) are invalid because they purport to give the Regulations retroactive effect. In the absence of an express or necessarily implied grant of statutory power to this effect, it is normally presumed that Parliament does not intend a regulation-making power to be exercised retroactively. This argument is considered separately as Issue 3.

[51]In addition, Apotex challenges the validity of the Regulations on a broader basis. It will be convenient at this point to set out again the part of the provision on which Apotex relies for this argument:

55.2 . . .

(4) The Governor in Council may make such regulations as the Governor in Council considers necessary for preventing the infringement of a patent by any person who makes, constructs, uses or sells a patented invention in accordance with subsection (1) or (2) including, without limiting the generality of the foregoing, regulations

[52]Apotex argues that this provision expressly imposes two limitations on the Governor in Council's regulation-making power. First, regulations can only be made to the extent that the Governor in Council considers them necessary for preventing the infringement of a patent. However, in view of the subjective terms in which this power is granted, counsel for Apotex wisely abandoned his previous argument that, since the Regulations covered situations in which there may have been no breach of a patent, they were not "necessary for preventing the infringement of a patent". I would only note at this point that the broad, subjective nature of the power delegated by subsection 55.2(4) may have a more general relevance in determining the validity of the Regulations.

[53]Second, such regulations can only be applied to a "second person" who has used a patented invention "in accordance with subsection (1) or (2)". This means, according to counsel, that since Apotex has not availed itself of either subsection, because it made its NDS before subsection 55.2 was enacted, the Regulations cannot apply to the submission for an NOC for norfloxacin that is under consideration here. Further, since

Apotex had a licence to use the patented product, it did not need the benefit of subsection 55.2(1) in any event.

[54]Hence, the argument goes, subsection 5(1) of the Regulations is invalid in so far as it purports to extend the Regulations to a submission filed, but not decided, before the Regulations came into effect, or to apply them to second persons who for other reasons have not availed themselves of the benefit of subsection 55.2(1) or (2).

[55]In addition to the plain meaning of subsection 55.2(4), counsel for Apotex relies on the Regulatory Impact Analysis Statement issued with the Regulations as evidence of the legislative intent underlying the scheme. It says that regulations are needed to ensure that generic drug companies do not abuse the authorization by subsections (1) and (2) of what would otherwise have been a patent infringement: using the patented invention as a comparator for the purpose of obtaining an NOC and stockpiling, and then starting to sell an infringing product prior to the expiry of the patent.

[56]Hence, if the "second person" has not availed itself of subsection (1) or (2), it will not have gained an advantage which it could abuse, and thus it is outside the mischief at which subsection 55.2(4) is aimed. If the "brand-name" company believes that a generic product infringes its patent, it is open to it to institute an action for infringement.

[57]Moreover, counsel submitted, the purpose of the *Patent Act Amendment Act, 1992* was to abolish compulsory licences for infringing pharmaceutical products, including those already granted after December 20, 1991 (subsection 12(1)) and, with some exceptions, to place patent holders for these products in much the same position as other patentees. If a generic manufacturer can produce and market a patented medicine without infringing the patent (for example, by discovering a non-infringing process when the patent is for the product manufactured by a particular process, or by obtaining a licence from the patentee), it is free to do so, provided that it obtained an NOC as a result of satisfying the Minister that its product is safe and effective.

[58]However, in recognition of the special features and importance of the pharmaceutical industry, the *Patent Act Amendment Act, 1992* in some ways limits the rights of pharmaceutical patent holders. For example, compulsory licences granted prior to December 20, 1991 remain valid (subsection 11(1)), and the Patented Medicines Review Board was given additional powers over the prices charged for patented medicines (section 7).

[59]Subsections 55.2(1) and (2) are the modifications to the statutory restoration of patent holders' rights relevant to this appeal. They are designed to ensure that patentees do not enjoy a *de facto* monopoly beyond the life of the patent by virtue of the length of time that it would take for a generic to obtain an NOC if it could not start its "regulatory work-up", or its manufacture and stockpiling of the product, until the patent had expired. Hence, it was argued, in order to ensure minimal deviation from the Act's central purpose, subsection 55.2(4) should be interpreted to authorize regulations that enhance the rights of patentees only in situations where a "second person" has taken advantage of the relaxation of patentees' rights contained in subsections (1) and (2).

[60]This narrow interpretation of the scope of subsection 55.2(4) is said to be justified because there is nothing in the overall scheme of the Act to indicate that it was the intention of Parliament to afford patentees of pharmaceutical products a degree of protection, such as that conferred by the Regulations, that goes well beyond that enjoyed by patentees of other products who must rely on the normal legal remedies available in the courts for preventing, or seeking compensation for, patent infringement.

[61]The learned Motions Judge rejected this argument, preferring an interpretation of subsection 55.2(4) in which the words, "any person who makes, constructs, uses or sells a patented invention in accordance with subsection (1) or (2)" are interpreted as "describing the general class of persons to whom regulations may be made applicable", not the activity in which a second person has engaged with respect to the particular product that is the subject of the proceeding. Hence, he concluded (*supra*, at page 550):

. . . regulations under subsection 55.2(4) may be adopted, with reference to all applicants for an NOC who did not have a vested right to a licence at the time the amending Act was adopted, whether or not they had already applied.

[62]Any other interpretation, he held, would lead to the anomaly of giving a compulsory licence to Apotex and others whose applications for an NOC were in the pipeline when the new statutory regime came into effect, even though the provisions creating such licences were repealed when the *Patent Act Amendment Act, 1992* came into force and compulsory licences granted before that date, but after December 20, 1991, were invalidated.

[63]Counsel seized on this part of the Motions Judge's reasons as indicative of a confusion between an NOC and a compulsory licence. Counsel pointed out that, before 1993 a "second person" who produced a pharmaceutical product by a non-infringing process did not require a compulsory licence, and thus would not have to have paid a royalty to the patent holder on the sales. It would be consistent with the new regime, it was argued, that NOC applications in the pipeline be examined by the Minister for safety and effectiveness, and an NOC issued if they satisfied these criteria. If, when the product was marketed, a "first person" believed that its patent was thereby infringed it could institute an action for patent infringement in the normal manner.

[64]Despite the argument seductively advanced on behalf of Apotex by Mr. Radomski, I am unable to accept it. The text of subsection 55.2(4) is linguistically capable of bearing either of the meanings that were posited in argument. However, if Parliament had intended to limit the scope of the regulation-making power to those who had taken advantage of subsection (1) or (2), it would have been more natural if the subsection had referred to "any person who <u>has made, constructed, used or sold</u> a patented invention in accordance with subsection (1) or (2)". The use of the present tense is more apt to describe a generic drug manufacturer at large, rather than one who <u>has done</u> any of the listed things on a particular occasion.

[65]While I recognize that the words chosen are a singularly odd way of expressing this idea, I find some comfort in the French version of subsection 55.2(4) which does

not use the word "person", and uses the expression "*au sens des paragraphes (1) ou (2)*", instead of "*en conformité avec les paragraphes (1) ou (2)*" meaning "in accordance with".

[66]Since the words of the statutory text do not point ineluctably to one conclusion, does the statutory context resolve the ambiguity? In my opinion, the nature and subjective definition of the purpose for which the power may be exercised supports a broad interpretation: "such regulations as the Governor in Council considers necessary for preventing the infringement of a patent".

[67]Thus, the Governor in Council could well consider that any second person, who was seeking an NOC for a new medicine that was on a first person's patent list, might be tempted, if the NOC were granted, to market its product prior to the expiry of the patent, and leave the first person to resort to whatever rights it was able to establish in a patent action. Given the reluctance of the courts to grant interlocutory injunctions in patent cases, and the length of time that it typically takes for a keenly contested patent matter to get to trial, the second person, armed with an NOC, would be able, in effect, to help itself to a *de facto* compulsory licence. The "royalty" payable would be the figure at which the dispute was settled, or the sum that a court ultimately awarded by way of damages or an accounting of profits following a finding of infringement.

[68]It would certainly have been consistent with the abolition of the compulsory licence for Parliament to have conferred a regulation-making power that was wide enough to prevent this kind of abuse. Viewed in this light, it would seem immaterial to the legislative intent whether or not the second person had taken advantage of the relaxation in patent law effected by subsection (1) or (2) with respect to a particular drug.

[69]Counsel for Apotex argued that this interpretation offends the scheme of the 1992 Act because, if accepted, it would create new rights for patentees, rather than simply restoring rights removed by the previous compulsory licensing provisions. However, it is more accurate to say that the Act creates only a new remedy for protecting the existing rights of patentees from infringement, namely enforcement proceedings for marketing a medicine without an NOC.

[70]Of course, there will be situations in which the second person is able to establish, in either a prohibition proceeding or a private patent action, that its product is made by a non-infringing process or that the first person's patent is invalid. Meanwhile, the second person will have been denied an NOC and kept out of the market. Again, it may be asked, how is this result consistent with the stated legislative aim of protecting patentees from infringement?

[71]The answer, surely, is that whether a second person is infringing may not be self-evident, but will require proof, which may be highly technical or inconclusive, or the determination of difficult legal questions about the construction or validity of the patent. An NOC is withheld from all second persons, even those who ultimately succeed in defeating the first person's claim, in order to protect patentees against those who, if granted an NOC, might be tempted to infringe. Moreover, since the time taken to process an NOC application means that the 24 months' statutory stay will often

have expired by the time that the process is complete, the regime may be less draconian in operation than it may seem on paper.

[72]For these reasons, and in accordance with the general directive of section 12 of the *Interpretation Act*, R.S.C., 1985 c. I-21, I have concluded that subsection 55.2(4) should be construed broadly, so that its application is not limited to those who have availed themselves of the benefits conferred by subsection (1) or (2) in connection with the particular medicine in dispute.

[73]I recognize that the Regulatory Impact Analysis Statement supports the more limited interpretation advanced on behalf of Apotex, as does a letter of February 5, 1993 from the Minister of Consumer and Corporate Affairs to the Canadian Drug Manufacturers Association (CDMA), in which the Minister said of subsection 55.2(4):

It is designed to enable the Government to mitigate any harm flowing from its decision to allow those activities that would otherwise constitute a patent infringement.

[74]However, I see no reason to regard these as necessarily more reliable guides to Parliament's intention than the fact that, in enacting the Regulations, the Governor in Council obviously took a broader view of the legislative power delegated by subsection 55.2(4) than that indicated by these documents.

[75]Although this suffices to dispose of Apotex' main contention on the validity of the Regulations, I should also deal with another line of argument that was debated at some length at the hearing. This concerns the relationships between subsections 55.2(1) and (2) of the Act on the one hand, and subsection 5(1) of the Regulations on the other. The question is whether the persons caught by subsection 5(1) must by definition also have availed themselves of subsection (1) or (2). If so, the Regulations will still be valid, even if subsection 55.2(4) is construed as narrowly as Apotex argues that it should be.

[76]Subsection 5(1) provides that the Regulations apply to persons who have filed a submission for an NOC and wish "to compare that drug with, or make reference to, another drug that has been marketed in Canada pursuant to a notice of compliance issued to a first person in respect of which a patent list has been submitted" [emphasis added]. On the other hand, subsection 55.2(1) refers to a person who has used the "patented invention" [emphasis added] for the purpose of obtaining regulatory approval for that person's new medicine.

[77]Counsel for Apotex argued that, contrary to the assumption on which subsection 5 (1) of the Regulations seems to have been drafted, a person could use a drug for comparison or reference purposes without thereby necessarily making use of a "patented invention" within the meaning of subsection 55.2(1). He submitted that this would be true, for example, in the case of a "product by process" patent, since to compare two drugs in order to obtain an NOC would not involve use of the "patented invention", which was not simply the drug, but the drug as made by a particular process. The process by which the medicine is manufactured is irrelevant to the comparative exercise undertaken to establish the equivalence of the medicines for the purpose of demonstrating safety and effectiveness.

[78]I cannot accept this argument. In *Deprenyl Research Ltd. v. Apotex Inc.* (1994), 55 C.P.R. (3d) 171 (F.C.T.D.); affd (1995), 60 C.P.R. (3d) 501 (F.C.A.), it was held that a claim for a particular process for producing a product, or a "pure process" claim, was not covered by the NOC Regulations because it was not a "claim for the medicine itself" within the meaning of section 2. However, the Regulations do include patents that contain a claim for a medicine when made by a particular process, or "a process dependant claim".

[79]Accordingly, since the product is always included in the patent's claim, whenever a generic manufacturer submits an abbreviated new drug submission and compares its product with a product on a first person's patent list, it is using "a patented invention" (assuming, of course, that the patent is subsequently held to be valid), whether it is the subject of a "process dependant patent" or a "product only" patent.

[80]Although initially made prior to the introduction of the Regulations, Apotex' submission for an NOC for its noxfloxacin, including the comparative analysis, remained before the Minister after March 1993, until July when the licence arrangement came into effect. This, together with Apotex' possession for regulatory purposes of a sample of the patented product, constituted use of a patented invention within the meaning of subsection 55.2(1): see *Smith Kline and French Laboratories Limited v. Douglas Pharmaceuticals Limited*, [1991] F.S.R. 522 (N.Z.C.A.); *Roche Products, Inc. v. Bolar Pharmaceutical Co. Inc.*, 733 F.2d 858 (Fed. Cir. 1984); *Hoffmann-La Roche Ltd. v. Canada (Minister of National Health and Welfare)* (1996), 67 C.P.R. (3d) 484 (F.C.T.D.), at page 489; affd (1996), 70 C.P.R. (3d) 1 and 206 (F.C.A.).

[81]For these reasons Apotex has not established that the NOC Regulations are in a substantive sense *ultra vires* subsection 55.2(4).

Issue 3: In the absence of an express statutory power authorizing the Governor in Council to enact regulations with retroactive effect, are the Regulations invalid in so far as they purport to apply to NOC submissions that had been made, but not decided, when the Regulations came into effect?

[82]In my view, the application of the Regulations to new drug submissions that were in the pipeline when the 1993 Regulations came into effect did not engage the presumption against retroactivity. No vested right was thereby abrogated: in the absence of a clear legislative indication to the contrary, no one has a legal right to have an application for a statutory benefit determined in accordance with the eligibility criteria in place when the application was made. Applicants for statutory rights normally have no more than a hope that the granting authority will render a favourable decision (see, for example, *Director of Public Works v. Ho Po Sang*, [1961] A.C. 901 (P.C.)), although a refusal of an application may be set aside if not in accordance with the law in force when the decision was made.

[83]By virtue of the *Interpretation Act*, R.S.C., 1985, c. I-21, paragraph 44(*c*), the presumption against retroactive operation of the repeal of an enactment protects rights that are both "accrued" and "accruing". If Apotex' application to the Minister did not constitute an accrued right to an NOC on the basis of statutory criteria in place when the application was made, was its right "accruing" within the meaning of paragraph 44

(*c*), and thus presumptively not subject to the regulation-making power conferred on the Governor in Council by subsection 55.2(4) of the *Patent Act*?

[84]Writing a separate concurring opinion in *Scott v. College of Physicians and Surgeons of Saskatchewan* (1992), 1992 CanLII 2751 (SK CA), 95 D.L.R. (4th) 706 (Sask. C.A.), Cameron J.A. held (at page 719) that the identical provision in paragraph 23(1)(*c*) of *The Interpretation Act,* R.S.S. 1978, c. I-11 protected only rights that would inevitably arise in due course, and not those that may

. . . ripen into an acquired or accrued right or obligation at a future time. As will be readily apparent, the implications of that in relation to the effectiveness of repeal are simply too wide to be acceptable.

[85]A similar point was made in *Hutchins v. Canada (National Parole Board)*, 1993 CanLII 2981 (FCA), [1993] 3 F.C. 505 (F.C.A.), leave to appeal refused [1994] 1 S.C.R. vii, where the Court held that the right of a prisoner to a hearing under a repealed provision in the statute was not "accruing" at the time of the repeal, even though the applicant had taken all the steps that he could take to institute the proceeding prior to the repeal.

[86]On the other hand, *Apotex Inc. v. Canada (Attorney General)*, 1993 CanLII 3004 (FCA), [1994] 1 F.C. 742 (C.A.); affd 1994 CanLII 47 (SCC), [1994] 3 S.C.R. 1100, provides an example of an "accruing" right within the scope of the presumption. In that case, the Minister had completed the regulatory approval process when the 1993 Regulations came into effect, so that all that remained was the formal step of issuing the NOC. In other words, at the time of the repeal, the grant of an NOC did not depend on a determination by the Minister, but followed inevitably from the approval of the application.

[87]It was therefore within the authority for the Governor in Council conferred by subsection 55.2(4) to provide expressly in the Regulations that they apply to submissions made before they came into effect, but not yet decided by the Minister. Accordingly, it was not unlawful for the Minister to refuse to issue an NOC to Apotex for the medicine norfloxacin, even though the submission was made before the grant of regulatory approval was linked to patent protection.

Issue 4: Are the Regulations invalid because they were made in breach of an undertaking by the Minister of Consumer and Corporate Affairs to the Canadian Drug Manufacturers Association that it would be consulted before regulations were enacted under subsection 55.2(4)?

(i) Factual background

[88]In July 1992 the CDMA was advised by a senior official in National Health and Welfare that regulatory approval of new drugs through the issue of a Notice of Compliance would be linked to the protection of the rights of existing patent holders although, as then drafted, Bill C-91 contained nothing to this effect.

[89]In the following month, the Association responded to record its opposition to any such scheme. These sentiments were repeated in November during the public hearings while Bill C-91 was in Committee stage. Meanwhile, the Pharmaceutical

Manufacturers Association of Canada, a not-for-profit corporation representing primarily "brand-name" pharmaceutical companies, urged before the Committee that such a linkage be established through regulations.

[90]In December 1992, the CDMA met with officials from the Department of Consumer and Corporate Affairs which had the carriage of the amendments to the *Patent Act*. The officials advised the Association that an amendment to Bill C-91 was to be introduced which would authorize the Governor in Council to enact regulations linking the previously separate issues of possible patent infringement and the grant of regulatory approval by the Minister of National Health and Welfare for new drugs.

[91]Despite the strong objection of the CDMA, which it communicated in letters to the Minister of Consumer and Corporate Affairs, and to the Minister of Industry, Science and Technology Canada, Bill C-91 was amended at third reading to add what became subsection 55.2(4) of the *Patent Act*. This authorized the making of regulations of the kind to which the CDMA had objected.

[92]After the passage of the Bill in the House of Commons, including this enabling provision, industry representatives made further submissions in January 1993 before the Senate Committee that was considering it. Meetings were also held at this time between the CDMA and a Deputy Minister of National Health and Welfare at which it was said that the Government intended to consult with the industry before enacting implementing regulations.

[93]In a letter dated February 5, 1993 written to Mr. Kay, the Chair of the CDMA, the new Minister of Consumer and Corporate Affairs, Mr. Vincent, reiterated the reasons for the amendment to Bill C-91 to which the CDMA had objected. He explained that the rationale for the proposed regulations was the need to minimize harm to patent holders that might otherwise result from the provisions permitting generic drug companies to use the patented product to obtain an NOC and to stockpile the product pending the expiry of the patent. The letter ended with the following sentence: "Rest assured that you will be consulted before any such regulations are established."

[94]On February 15, 1993, Bill C-91 came into force as the *Patent Act Amendment Act, 1992*, with the exception of section 55.2, which includes the controversial provision enabling the making of regulations. This section came into force on March 12, 1993, along with the *Patented Medicines (Notice of Compliance) Regulations* that created the statutory scheme implementing the linkage of the protection of patent rights and the issue of an NOC. Despite the assurance contained in the Minister's letter of February 5, 1993, the CDMA was not consulted on the content of the Regulations prior to their enactment.

[95]The Regulatory Impact Analysis Statement issued with the Regulations stated that, while the principal stakeholders had been consulted on the principle of Bill C-91, "given the importance of quickly giving effect to the new statute" there had been no consultation on the text of the Regulations prior to their coming into force. Under the Federal Regulatory Plan early notice of regulations is normally given so that those interested may comment on them before they are promulgated. However, since these Regulations were new, the Government undertook to consult on their operation and to refine them if and as necessary.

[96]Over the next few years there were extensive consultations with industry members and their representative associations. As a result of the experience obtained from the operation of the Regulations and, no doubt, from the consultations, extensive amendments were made to the Regulations, which came into force in 1998 as the *Regulations Amending the Patented Medicines, (Notice of Compliance) Regulations*, SOR/98-166.

[97]Among other things, the amendments which, for the most part, favoured generic drug manufacturers, reduced from 30 months to 24 months the automatic stay on the grant of an NOC that comes into effect when a proceeding for a prohibition is instituted: subsection 6(2) of the 1998 Regulations, amending paragraph 7(1)(*e*) of the 1993 Regulations. The statutorily imposed stay is the aspect of the Regulations that generic drug manufacturers believe to be perhaps most damaging to their interests.

[98]While of a relatively technical nature, these amendments cumulatively may have mitigated the adverse impact that the statutory linkage of patent protection and regulatory approval had on generic manufacturers. Nonetheless, the essential principle and general design of the scheme remained in place.

(ii) Subordinate legislation and legitimate expectations

[99]There is an easy answer to the question of whether the 1993 Regulations are invalid because they were enacted without the consultation that the CDMA had been promised by the Minister. It is that, in the absence of any statutory requirement of consultation prior to the promulgation of regulations, the duty of fairness is the only legal source for a legal obligation to consult.

[100]However, the duty of fairness does not apply to the exercise of powers of a legislative nature (*Attorney General of Canada v. Inuit Tapirisat of Canada et al.*, 1980 CanLII 21 (SCC), [1980] 2 S.C.R. 735), including regulations that apply to a particular industry (*Canadian Assn. of Regulated Importers v. Canada (Attorney General*), 1994 CanLII 3460 (FCA), [1994] 2 F.C. 247 (C.A.), leave to appeal refused [1994] 2 S.C.R. vi; *Carpenter Fishing Corp. v. Canada,* 1997 CanLII 6391 (FCA), [1998] 2 F.C. 548 (C.A.), leave to appeal refused [1998] 2 S.C.R. vi). Accordingly, there was no legal obligation to consult with the CDMA prior to the enactment of the 1993 Regulations.

[101]Nor, according to this argument, could the Minister's undertaking to consult attract a legal duty to do so. This is because the basis of such a duty could only be that it created a legitimate expectation of consultation and, since this doctrine is no more than an aspect of the duty of fairness, it can have no application to the exercise of a power to which the duty itself does not apply.

[102]Indeed, in *Reference re Canada Assistance Plan (B.C.)*, 1991 CanLII 74 (SCC), [1991] 2 S.C.R. 525, at pages 557-560, it was specifically said that the doctrine of legitimate expectations has no application to the exercise of legislative powers. In addition, in *Old St. Boniface Residents Assn. Inc. v. Winnipeg (City)*, 1990 CanLII 31 (SCC), [1990] 3 S.C.R. 1170, at page 1204, the Court rejected a challenge to the validity of municipal bylaws that was based on an allegation that they were passed in breach of a legitimate expectation of prior consultation.

[103]This was the ground on which the learned Motions Judge dismissed the legitimate expectation argument in the instant case. He buttressed it by noting that, in any event, the statutory power in question, namely the power to enact regulations, was conferred on the Governor in Council which itself gave no procedural undertaking to the CDMA and could not be bound by the one given by the Minister.

[104]It is settled law in Canada that the duty of fairness does not apply to the exercise of powers of a legislative nature, which would include the Regulations impugned in this case. Although they applied to a relatively small and readily identifiable group, the Regulations are at the "legislative" end of the spectrum of powers ranging from the legislative, through the administrative, to the judicial. This is because they were made under a broad statutory discretion by the Governor in Council conferred by subsection 55.2(4): "The Governor in Council may make such regulations as the Governor in Council considers necessary" [emphasis added], and are of general application to all those engaged in the pharmaceutical industry.

[105]However, it does not necessarily follow that subordinate legislation can lawfully be made in breach of a categorical and specific assurance of prior consultation given to an individual by a responsible minister of the Crown in the course of discharging departmental business. Nor, on closer examination, does the case law so provide.

[106]While in the *Canada Assistance Plan* case, *supra*, the Supreme Court of Canada clearly reiterated (at page 558) the orthodox position that the duty of fairness does not apply to legislative powers so as to require prior notice before their exercise, that case does not, in my opinion, also support the view that the legitimate expectations doctrine is equally inapplicable.

[107]The issue in that case relevant here concerned the legal effect of a breach of section 8 of the *Canada Assistance Plan*, R.S.C. 1970, c. C-1. This provided that the terms of the agreement entered into under the Plan would not be amended by the federal government except with the consent of the province, and could only be terminated by either party on the giving of twelve months' notice of an intention to terminate.

[108]The Court held that this provision did not impose a substantive fetter on the right of Parliament from time to time to pass such legislation within its constitutional powers as it thinks fit. The Court then considered whether this provision created a legitimate expectation of prior consultation before a unilateral amendment to the Plan was made, and whether the federal government acted unlawfully when it introduced legislation in Parliament to amend the funding formula without consulting the Province.

[109]The Court dismissed the argument (at pages 559-560) on the ground that, to invoke the doctrine of legitimate expectations to create a procedural entitlement in this case would unduly limit the exercise by Parliament of its power to enact legislation in the normal manner and form on matters within its constitutional competence, and thus "place a fetter on this essential feature of democracy."

[110]Similar constitutional considerations do not apply to the exercise of delegated legislative powers which is not subject to the same level of scrutiny as primary

legislation that must pass through the full legislative process. Moreover, the procedural rights created by the legitimate expectations doctrine are always subject to proof that, in particular circumstances, the public interest requires that administrative action be taken promptly without complying with the promised procedures.

[111]The *Old St. Boniface* case, *supra*, might seem to be more on point because it concerned the enactment by a municipality of zoning bylaws which, like regulations, are a species of delegated legislation. However, in dismissing the argument that a promise by a committee Chair of further consultation created a legitimate expectation, the Court emphasized (at page 1204) the presence of a procedural code specifically created by the statute for the enactment of zoning bylaws. For the courts to add to this process through the doctrine of fairness, by way of the legitimate expectations doctrine, would be both unnecessary for achieving fairness and inconsistent with the statutory procedural scheme which was "an elaborate structure designed to enable all those affected not only to be consulted but to be heard."

[112]In contrast, there are no statutory provisions requiring consultation with those interested before regulations are enacted under the *Patent Act*. There is no reason, therefore, why, to borrow the words of Sopinka J. in *Old St. Boniface, supra* (at page 1204), the Court in this case should not, supply

. . . the omission where, based on the conduct of the public official, a party has been led to believe that his or her rights would not be affected without consultation.

[113]Nor do I think that *Baker v. Canada (Minister of Citizenship and Immigration)*, 1999 CanLII 699 (SCC), [1999] 2 S.C.R. 817 is opposed to the application of the legitimate expectations doctrine to delegated legislative powers so as to require prior consultation before they may be validly exercised. In that case L'Heureux-Dubé J. stated (at page 839, paragraph 26), that in Canada a legitimate expectation can increase the procedural content of the duty of fairness beyond that which it would otherwise have had. I infer from the context in which this statement was made that L'Heureux-Dubé J. simply intended to make it clear that in our law the doctrine does not give rise to substantive rights, contrary, for example, to the position recently taken in England by the Court of Appeal in the important case of *Coughlan v. North and East Devon Health Authority*, [1999] E.W.J. No. 3774 (C.A.) (QL).

[114]Hence, I do not interpret L'Heureux-Dubé J. also to be saying that a representation that a person will have an opportunity to participate can never give rise to a legitimate expectation of participatory rights in respect of administrative action to which the duty of fairness would not otherwise apply. Indeed, later in the same paragraph (at page 840), L'Heureux-Dubé J. committed herself to the general proposition that the doctrine of legitimate expectations is based on the premise that it is generally unfair for decision makers to go back on a procedural undertaking. She did not limit this statement of principle to instances where the effect of applying the legitimate expectations doctrine is simply to enhance the content of the duty of fairness in a situation where it would otherwise have imposed some, but lesser, participatory rights.

[115]Indeed, there are decisions holding that the doctrine of legitimate expectations may apply to a public authority that represents that it will follow a certain procedure

before exercising a power to which the duty of fairness would probably not otherwise extend, including those of a policy or legislative nature. See, for example, *Old St. Boniface Residents Assn. Inc. v. Winnipeg (City)*, *supra*; *Lehndorff United Properties (Canada) Ltd. et al. v. Edmonton (City)* (1993), 146 A.R. 37 (Q.B.) and cases cited therein, affd on other grounds (1994), 1994 ABCA 276 (CanLII), 157 A.R. 169 (C.A.), leave to appeal refused [1995] 2 S.C.R. vii; *Bezaire v. Windsor Roman Catholic Separate School Board* (1992), 1992 CanLII 7675 (ON SC), 9 O.R. (3d) 737 (Div. Ct.).

[116]However, not all decisions point in this direction: see, for example, *Sunshine Coast Parents for French v. School District No. 46 (Sunshine Coast)* (1990), 1990 CanLII 260 (BC SC), 44 Admin. L.R. 252 (B.C.S.C.), which has been the subject of trenchant criticism: see David J. Mullan, "Confining the Reach of Legitimate Expectations: Case Comment: *Sunshine Coast Parents for French v. School District No. 46 (Sunshine Coast)*" (1991), 44 Admin. L.R. 245.

[117]It is also of interest that other common law jurisdictions have been prepared to apply the legitimate expectations doctrine in its procedural sense to the exercise of rule-making powers, especially when, as here, the delegated legislation applies most immediately to a defined group, even though, like Canada, these jurisdictions do not normally apply the duty of fairness to legislative powers or policy-based decisions: see, for example, *Regina v. Liverpool Corpn., Ex parte Liverpool Taxi Fleet Operators' Association*, [1972] 2 Q.B. 299 (C.A.); *Council of Civil Service Unions v. Minister for the Civil Service*, [1985] A.C. 374 (H.L.); *R. v. Lord Chancellor's Department, ex parte Law Society* (Q.B.D. Crown Office List; June 22, 1993; CO/991/93); Philip A. Joseph, *Constitutional and Administrative Law in New Zealand* (Sydney, N.S.W.: Law Book Co., 1993), at pages 754-756.

[118]There is also impressive support in the secondary literature for the proposition that the creation of a legitimate expectation of consultation should limit the general principle that the duty of fairness does not apply to the exercise of powers of a legislative nature: see, for example, David J. Mullan, "*Canada Assistance Plan*--Denying Legitimate Expectation a Fair Start?" (1993), 7 Admin. L.R. (2d) 269, and the particularly valuable analysis by Joan G. Small, "Legitimate Expectations, Fairness and Delegated Legislation" (1995), 8 *C.J.A.L.P.* 129.

[119]A somewhat different view is advanced by David Wright, "Rethinking the Doctrine of Legitimate Expectations in Canadian Administrative Law" (1997), 35 *Osgoode Hall L.J.* 139, at pages 188-193, where the author argues that the essential problem with the common law in this area is its unnuanced refusal to extend the duty of fairness, so as to confer on those affected a general right to participate in the legislative process prior to the enactment of delegated legislation or the making of other policy-based decisions.

[120]To impose a duty on rule makers to consult, or to engage in some other form of public participation only when a legitimate expectation of a procedural nature has been created as a result of the conduct of officials, Wright argues, is an oblique and incomplete solution to the more basic problem: the failure of the law to strengthen the democratic legitimacy of delegated legislation by imposing through the common law duty of fairness a process in which those interested are entitled to participate.

[121]However, in my view the interests protected by the doctrine of legitimate expectations are not the same as those protected by a general duty to afford an opportunity to those affected to participate in the rule-making exercise. The bases of this latter duty are the democratic values of accountability, the claim of the governed to attempt to influence the content of the law to which they will be subject, and the belief that a better considered measure is likely to emerge from a consultative process. In contrast, holding government to a procedural undertaking that was solemnly given on its behalf to an individual is more a matter of individual justice.

[122]When a legitimate expectation arises from an agency's past practice, or non-statutory procedural guidelines, it serves to preclude procedural arbitrariness, not the actual expectation of the individual who may have been unaware of its existence. However, where the legitimate expectation arises from a promise or undertaking, categorically and specifically given to an individual or a defined group, the rationale for holding the government to it derives from the individual's reliance interest or, in the absence of a detrimental reliance, from the individual's right to expect that, in the absence of a compelling reason for not so doing, the government will act with basic decency by keeping promises that it makes to individuals.

[123]The interests underlying the legitimate expectations doctrine are the non-discriminatory application in public administration of the procedural norms established by past practice or published guidelines, and the protection of the individual from an abuse of power through the breach of an undertaking. These are among the traditional core concerns of public law. They are also essential elements of good public administration. In these circumstances, consultation ceases to be a matter only of political process, and hence beyond the purview of the law, but enters the domain of judicial review.

[124]Accordingly, in my view the legitimate expectations doctrine is not simply a branch of the duty of fairness, in the sense that it serves the same purposes as the participatory rights conferred by the duty of fairness. Hence, there is no reason to limit its reach to the exercise of statutory powers to which the duty applies.

[125]On the other hand, as with the duty of fairness, a breach will lead to the imposition of procedural duties, generally of a participatory nature, on the person or body empowered to take some administrative action, rather than requiring a particular substantive outcome to the exercise of power. Indeed, when in *Baker v. Canada (Minister of Citizenship and Immigration), supra*, at page 839, paragraph 26, the Supreme Court of Canada recently located the legitimate expectations doctrine within the duty of fairness it was in response to an argument that a person may have a legitimate expectation of receiving a substantive, and not merely a procedural benefit. And, in the *Canada Assistance Plan* case, *supra*, the Court's concern was to preserve the sovereignty of Parliament from the imposition of novel manner and form requirements on the enactment of legislation. However, in *Old St. Boniface Residents Assn. Inc. v. Winnipeg (City)*, *supra*, where no contrast was made with substantive rights, it was said only that, as developed in the English cases, the legitimate expectations doctrine was an <u>extension</u> of the duty of fairness.

[126]Therefore, in the absence of binding authority to the contrary, I conclude that the doctrine of legitimate expectations applies in principle to delegated legislative powers

so as to create participatory rights when none would otherwise arise, provided that honouring the expectation would not breach some other legal duty, or unduly delay the enactment of regulations for which there was a demonstrably urgent need (see *R. v. Lord Chancellor's Department, ex parte Law Society* (Q.B.D. Crown Office List; June 22, 1993; CO/991/93)).

[127]A court may set aside, or declare invalid, subordinate legislation made in breach of a legal duty to consult: *R v Secretary of State for Health, ex p US Tobacco International Inc*, [1992] 1 All ER 212 (Q.B.D.), at page 225. For this purpose it should not matter whether the duty arose from statute or by virtue of a promise that created a legitimate expectation of consultation. It remains to consider whether a legitimate expectation arose on the facts of this case and, if it did, whether the Regulations were enacted in breach of it.

(iii) Did a legitimate expectation arise on these facts?

[128]Whether a promise by a public official or body that consultation will precede administrative action gives rise to a legitimate expectation that attracts a legal obligation to consult depends on the surrounding facts. The question has both factual and normative aspects: <u>would</u> a reasonable person think that the promise was serious, and <u>should</u> a reasonable person be entitled so to think?

[129]On the facts of this case, I have no doubt that the words used were capable of creating a legitimate expectation that the Minister <u>would</u> consult the CDMA before any regulations made under subsection 55.2(4) came into effect. This is because of the specific and categorical nature of the assurance of consultation, given in a letter written by the Minister responsible for the development of regulations in response to the concerns expressed by the Association in the course of discussions about the course on which the Government appeared set.

[130]I do not think that it is necessary for the Minister to have gone further in the letter by, for example, proposing a timetable for the consultation process. I note that in the *Liverpool Taxi* case, *supra*, a legitimate expectation was held to have been created when the town clerk wrote to the solicitors of the taxi owners' association that, before a decision was taken to increase the number of licences available, "you have my assurance that interested parties would be fully consulted." A similar assurance was given orally by the chair of the relevant committee of the municipal council.

[131]In my opinion, Canadians would expect, and are entitled to expect, that a clear and unequivocal undertaking of consultation, given in writing to an individual or an association by a minister of the Crown, will be honoured, in the absence of some compelling reason for not so doing.

[132]There is, however, another aspect of the legitimacy of the expectation to be addressed: can an undertaking given by a minister that there will be consultation prior to the enactment of regulations give rise to a legitimate expectation when the Governor in Council, not the minister, has the statutory authority to make the regulations in question?

[133]Not surprisingly, there is no evidence that the Governor in Council expressly delegated to the Minister of Consumer and Corporate Affairs the authority to impose procedural restrictions on the exercise of the Cabinet's regulation-making power. Nonetheless, when the promise of prior consultation is made by the minister with primary responsibility for developing regulations and bringing them before Cabinet, a citizen may reasonably assume that in so doing the minister is acting within his or her authority, whether express or implied. Accordingly, it may be open to those to whom the promise was made to seek judicial review to prevent the minister from taking proposed regulations to Cabinet until the promised consultation has occurred.

[134]In this case, however, the Cabinet has already approved the regulations, and the question is whether their validity can be impugned because they were enacted in the absence of the consultation that the minister promised. In my view, it cannot. If the Cabinet enacts regulations in ignorance of an undertaking of consultation given by a minister, it would not seem to me to have abused its statutory power. And, given the legal protection afforded by the law to the confidentiality of cabinet proceedings and the narrow grounds on which the courts review the exercise of powers by the Cabinet, it would be impermissible for a court to enquire into the state of knowledge possessed by members of the Cabinet about prior procedural assurances given by a minister in order to determine whether otherwise valid regulations were knowingly enacted in breach of a ministerial undertaking.

[135]Hence, in my view, the Minister's assurance did not create in the CDMA a legitimate expectation of consultation that, if breached, would invalidate Regulations enacted by the Cabinet without the promised consultation. This is sufficient to dispose of the challenge to the validity of the NOC Regulations based on the legitimate expectations doctrine. However, I should also consider another argument advanced before us, namely, that any duty to consult attracted by the Minister's undertaking was in fact discharged.

(iv) Was there sufficient consultation?

[136]An undertaking to consult prior to the enactment of delegated legislation cannot be discharged without affording the individual to whom it was given a reasonable opportunity to attempt to influence its content, especially on matters of a secondary policy or technical nature. In order to honour such an undertaking the process of consultation should generally include the disclosure of the text of the proposed regulations, together with an explanatory statement, and sufficient time for this material to be studied and a response prepared: see, for instance, *R. v. Brent London Borough Council, Ex p Gunning* (1985), 84 L.G.R. 168 (Q.B.D.).

[137]None of these elements of consultation was present in this case prior to the publication of the 1993 Regulations. However, there had been consultations between the Government and the CDMA and others on Bill C-91, including the regulation-making provision which was added only at third reading. At this point it was made clear to the CDMA that the Government intended to provide by regulations for the linkage of patent protection and the issue of NOCs.

[138]The CDMA is a sophisticated combatant in the high-stakes battles that the "generic" and "brand-name" branches of the pharmaceutical industry have waged for

years, with both political and legal weaponry, over regulatory approval for new drugs and patent rights. Although the 1992 Act and the implementing Regulations undoubtedly represented a serious setback for the generic drug manufacturers, the CDMA cannot plausibly claim that the essential scheme of the 1993 Regulations came as a complete surprise.

[139]Indeed, after the addition to Bill C-91 of what became subsection 55.2(4) of the amended *Patent Act*, the PMAC, to the knowledge of the CDMA, continued to press the Government to put in place regulations that would ensure that an NOC could not be issued to a generic manufacturer in circumstances that might enable it to market a drug that infringed a patent held by a "brand-name" company. However, despite the political know-how of the CDMA, it is plausible to believe that it ceased to make further representations of its own after it received the Minister's assurance of consultation. It might, for example, have been using the time to organize for the forthcoming consultations that it had been led to believe would take place.

[140]Even for a body with the knowledge, resources and experience that it is reasonable to attribute to the CDMA, there is a very big difference, especially given the technical complexity of the scheme, between being able to anticipate the general content of regulations likely to be enacted to implement known government policy, and having time to study and comment on the text of the proposed regulations and their stated rationale. Indeed, subsequent events suggest that, if consultation had occurred as promised by the Minister, it might have enabled the CDMA to persuade the Government to modify some features of the proposed regulations before their enactment by Cabinet.

[141]Accordingly, standing alone the consultation that took place before the Minister gave his assurance, and in the absence of a published text of proposed regulations, would not be sufficient to mitigate the abuse of power inherent in the failure to honour the undertaking of prior consultation.

[142]However, after the Regulations came into effect in March 1993 the CDMA, along with other members of the pharmaceutical industry, met and communicated often and at great length with the relevant ministers and their senior officials about the Regulations. And, as I have already noted, the 1993 Regulations were significantly modified in 1998.

[143]In these circumstances, it was submitted, any failure to consult on the text of the 1993 Regulations before they were enacted was effectively "cured". The Minister's promise had been so substantially performed that it would be inappropriate for the Court to invalidate complex regulations that seek to strike a balance between two sets of conflicting interests: on the one hand, the commercial interests of the "brand-name" companies in protecting their proprietary rights and of the "generic" companies in competing in the market and, on the other, the public's interests in better drugs and cheaper drugs.

[144]It goes without saying that, as a general rule, consultation will generally be more effective if it occurs well before administrative action is finalized than if it occurs after the die is cast for all practical purposes, save, perhaps, for relatively minor adjustments. Indeed, in other administrative contexts it is rare that a duty to conduct a

hearing before a decision is made will be satisfied by an after-the-fact hearing by the same body. However, in our case it can be inferred from the context, including the addition of subsection 55.2(4), that the consultation promised related to the implementing details of the scheme and not to the principle of linking patent protection and regulatory approval.

[145]In my opinion, the extensive and effective consultations that occurred after 1993, and prior to the amendments of the Regulations in 1998, would make it inappropriate to declare invalid the original Regulations as amended. I am not satisfied that the procedures eventually afforded to the CDMA were so inadequate that the failure to provide an opportunity to consult at the promised time would warrant the invalidation of the Regulations as an abuse of power, especially given the CDMA's involvement in the process before the enactment of Bill C-91, and its understanding of the issues.

[146]It is certainly possible to argue that, if the consultations had occurred when promised, many of the subsequently identified wrinkles in the 1993 Regulations would have been ironed out much earlier. On the other hand, it is also possible that the Government was only prepared to modify the 1993 Regulations in light of several years of experience with the new scheme. Hence, whether the amendments made in 1998 following consultation with the CDMA and others would have been made earlier if the consultations had taken place as promised is a matter of mere speculation.

[147]Of course, courts do not normally determine whether a breach of the duty of fairness occurred or, if it did, whether it should result in the quashing of the decision or order concerned, by asking whether the result would have been different if the decision maker had meticulously observed the procedural proprieties: *Cardinal et al. v. Director of Kent Institution*, 1985 CanLII 23 (SCC), [1985] 2 S.C.R. 643.

[148]However, given the narrow grounds on which the courts have normally subjected regulations to judicial review (*Thorne's Hardware Ltd. et al. v. The Queen et al.*, 1983 CanLII 20 (SCC), [1983] 1 S.C.R. 106) and the realities of the political context of the consultative process, the consultations that occurred after the Regulations came into force in 1993 effectively drew the sting of the abuse of power that occurred when the Minister breached his solemn undertaking to consult prior to the enactment of the 1993 Regulations.

(v) Standing

[149]Although the point was not raised by the parties, I had some concerns about whether it was open for an intervener, the CDMA, to rely on a ground of review that was probably not available to the applicant: normally only those to whom a promise was made may rely on it as the basis for relief in an application for judicial review. And, since the CDMA is an intervener in, and not a party to, the application for judicial review, it is difficult to see how relief could be granted to the applicant, Apotex, on the basis of a defeat of the CDMA's legitimate expectation of consultation.

[150]In view of my earlier conclusion that the Minister's undertaking could not invalidate the Regulations enacted by the Governor in Council, it is not necessary for me to provide a definitive answer to this question. However, the fact that the CDMA was given leave to intervene in the application does not preclude the Court, after

hearing the application on its merits, from deciding that the intervener's point, though meritorious in principle, does not warrant judicial intervention because it is not one on which the applicant could rely.

[151]On the other hand, since the applicant, Apotex, is the largest generic drug manufacturer in Canada and hence, as a member of the association, can be expected to play a major role in the affairs of the CDMA, it would be unduly formalistic to draw such a sharp distinction between Apotex, the applicant, and the industry association, the intervener, that a breach of an undertaking given to the latter could not be the basis for granting a declaration of invalidity to the former, one of its members.

D. CONCLUSION

[152]For these reasons I would dismiss the appeal on the terms set out in paragraph 26 of the reasons of my colleague, Décary J.A.

[1] R.S.C., 1985, c. P-4, as amended.

[2] See, for ex., the *Canada Shipping Act*, R.S.C., 1985, c. S-9 , s. 95(1) [as am. by R.S.C., 1985 (3rd Supp.), c. 6, s. 5]; the *Canadian Human Rights Act*, R.S.C., 1985, c. H-6 , s. 15(4) [as am. by S.C. 1998, c. 9, s. 10] and the *Copyright Act*, R.S.C. 1985, c. C-42 , s. 66.6(2) [as enacted by R.S.C., 1985 (4th Supp.), c. 10, s. 12].

[3] R.S.C., 1985, c. S-22.

[4] See, for example, the *Canada Labour Code*, R.S.C., 1985, c. L-2 , s. 159(2) [as enacted by S.C. 1996, c. 12, s. 3]; the *Official Languages Act*, R.S.C., 1985 (4th Supp.), c. 31, s. 84; the *Civil Air Navigation Services Commer-cialization Act*, S.C. 1996, c. 20, s. 12(2); the *Hazardous Materials Information Review Act*, R.S.C., 1985 (3rd Supp.), c. 24, Part III, s. 48(1); the *Hazardous Products Act*, R.S.C. 1985, c. H-3 , s. 19 [as am. by R.S.C., 1985 (3rd Supp.), c. 24, s. 1] and the *Mackenzie Valley Resource Management Act*, S.C. 1998, c. 25, ss. 90, 143, 150.

[5] *Regulations Act*, R.S.Q., c. R-18.1, ss. 8, 10.

[6] A.B., vol. 7, at p. 1847.

[7] *Ibid.*, at pp. 1851-1852.

[8] See 1996 CanLII 11747 (FC), [1997] 1 F.C. 518 (T.D.), at p. 536.

[9] See, for ex., *Pulp, Paper and Woodworkers of Canada, Local 8, et al. v. Canada (Minister of Agriculture) et al*. (1994), 174 N.R. 37 (F.C.A.), at p. 49, Desjardins J.A.

[10] R.S.C., 1985, c. I-21.

[11] 30 & 31 Vict., c. 3 (U.K.) [(as am. by *Canada Act 1982*, 1982, c. 11 (U.K.), Schedule to the *Constitution Act, 1982*, Item 1) [R.S.C., 1985, Appendix II, No. 5]].

[12] 1991 CanLII 74 (SCC), [1991] 2 S.C.R. 525, at pp. 557-560.

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2007-0905

IN THE MATTER OF AN APPLICATION BY

ONTARIO POWER GENERATION INC.

PAYMENT AMOUNTS FOR PRESCRIBED FACILITIES

DECISION WITH REASONS

November 3, 2008

EB-2007-0905

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

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

BEFORE: Gordon Kaiser
Presiding Member & Vice Chair

Cynthia Chaplin
Member

Bill Rupert
Member

DECISION WITH REASONS

NOVEMBER 3, 2008

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C- Decision on Interim Payments in EB-2007-0905

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E- Ontario Regulation 53/05

F- Memorandum of Agreement between OPG and the Province of Ontario

1 INTRODUCTION

This proceeding concerned an application by Ontario Power Generation Inc. (OPG) under section 78.1 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15 (Schedule B) (*OEB Act*) requesting Board approval for payment amounts with respect to six hydroelectric generating stations and three nuclear generating stations owned and operated by OPG.

This was an unusual proceeding in at least two respects. First, until now the Board has not regulated the prices charged by electricity generators in Ontario. Second, regulations under the *OEB Act* constrain in some important respects the scope of the Board's consideration of OPG's application as compared to the scope of the Board's hearings on rates charged by transmitters and distributors.

This chapter briefly describes the generation facilities in question and summarizes OPG's application. It also describes the legislative framework that governs the Board's setting of payment amounts for OPG's facilities and how that framework affected this proceeding.

Details of the procedural aspects of this proceeding are contained in Appendix A.

1.1 The Prescribed Generation Facilities

OPG requested that the Board approve payment amounts for nine generating stations. These facilities, and their nameplate capacities, are listed in Table 1-1. These plants are referred to as the "prescribed generation facilities" under regulations to the *OEB Act*, and that term is used extensively in this decision. (OPG's other generating facilities are unregulated, including various hydroelectric and fossil fuel stations.)

The nine generating stations have a combined capacity of 9,938 MW, or about 45% of OPG's total generation capacity. The Sir Adam Beck Pump Generating Station, which is integrated with the Beck complex, provides the bulk of the peaking capability from OPG's regulated facilities. The other plants are "baseload" facilities although the other hydroelectric facilities have some minor peaking capability.

10 IMPLEMENTATION

OPG proposed that its new payment amounts be made effective April 1, 2008 and that the retrospective amounts to April 1, 2008 should be recovered over the balance of the test period outstanding at the time of the issuance of the Board's Decision, through the monthly payments OPG receives from the IESO. The amount to be recovered for the retrospective period would be equal to the difference between the new payments approved by the Board, multiplied by actual production from the regulated facilities during that period, and the actual revenues received by OPG under the existing payment amounts, excluding any hydroelectric incentive revenues.

AMPCO supported OPG's proposal to recover the retrospective amounts back to April 1, 2008 using actual consumption. SEC proposed that the new payment amounts be effective April 1, 2008 except for that portion related to OPG's increased return on equity. No other intervenors made submissions on OPG's implementation proposal. OPG urged the Board to accept OPG's proposal for implementing the new payment amounts, and to reject SEC's proposal.

The Board has determined that the new payment amounts will be effective April 1, 2008 and that the shortfall for the period from April 1, 2008 to the implementation of the Board's order should be recovered over the balance of the test period.

The Board directs OPG to file with the Board, and copy all intervenors, a draft order which will include the final revenue requirement and payment amounts for the prescribed nuclear and hydroelectric faculties, and reflect the findings made by the Board in this Decision. OPG should also include supporting schedules and a clear explanation of all calculations and assumptions used in deriving the amounts used.

With respect to the calculation of the payment amounts, OPG should assume that the IESO can start billing the new rates as of December 1, 2008 and that the payment amounts will be adjusted through the use of a rider to allow for the recovery of the 21 month revenue requirement over the 13 month period remaining in the test period.

With regard to the calculation of production for April 1, 2008 to November 30, 2008, OPG should use the monthly forecasts for both hydroelectric and nuclear production which underpinned its application. This will ensure that OPG remains at risk for its production forecast in the same way it would have been had the payment amounts been set on a prospective basis.

OPG is directed to file the draft order within 10 calendar days of the issuance of this decision. Intervenors shall have 7 calendar days to respond to the Company's draft order. The Company shall respond within 5 calendar days to any comments by intervenors.

DATED at Toronto, November 3, 2008

ONTARIO ENERGY BOARD

Original Signed By

____
Gordon Kaiser
Presiding Member & Vice Chair

Original Signed By

____
Cynthia Chaplin
Member

Original Signed By

____
Bill Rupert
Member

Ontario Energy Board | Commission de l'énergie de l'Ontario

Ontario

EB-2010-0008

IN THE MATTER OF AN APPLICATION BY

ONTARIO POWER GENERATION INC.

PAYMENT AMOUNTS FOR PRESCRIBED FACILITIES FOR 2011 AND 2012

DECISION WITH REASONS

March 10, 2011

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EB-2010-0008

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

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

BEFORE: Cynthia Chaplin
Presiding Member & Chair

Marika Hare
Member

Cathy Spoel
Member

DECISION WITH REASONS

MARCH 10, 2011

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Appendices:

1 INTRODUCTION

Ontario Power Generation Inc. ("OPG") filed an application with the Ontario Energy Board (the "Board") on May 26, 2010. The application was filed under section 78.1 of the *Ontario Energy Board Act, 1998*, S.O 1998, c. 15 (Schedule B) (the "Act"), seeking approval for payment amounts for OPG's prescribed generation facilities for the test period January 1, 2011 through December 31, 2012, to be effective March 1, 2011. The Board assigned the application file number EB-2010-0008.

OPG also requested that the Board issue an order declaring the current payment amounts interim if the new payment amounts are not implemented by March 1, 2011. By order dated February 17, 2011, the Board declared the current payment amounts interim effective March 1, 2011.

1.1 Legislative Requirements

Section 78.1(1) of the Act establishes the Board's authority to set the payment amounts for the prescribed generation facilities. Section 78.1 can be found at Appendix D of this Decision. 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 Board may establish the form, methodology, assumptions and calculations used in making an order that sets the payment amounts. O. Reg. 53/05

14 IMPLEMENTATION AND COST AWARDS

14.1 Implementation

OPG proposed that its new payment amounts be made effective March 1, 2011.

On February 17, 2011, the Board issued an interim order making the current payment amounts interim effective March 1, 2011.

The new payment amounts will be made effective March 1, 2011. The Board understands that the IESO can implement this effective date through its billing processes without the necessity for a shortfall payment amounts rider to cover the period between March 1 and the date of the final payment amounts order.

The Board directs OPG to file with the Board, and copy to all intervenors, a draft payment amounts order which will include the final revenue requirement and payment amounts for the regulated hydroelectric and nuclear facilities, and reflect the findings made by the Board in this Decision. OPG should also include supporting schedules and a clear explanation of all calculations and assumptions used in deriving the payment amounts and the payment riders.

OPG is directed to provide a full description of each deferral and variance account as part of the draft payment amounts order.

OPG is directed to file the draft payment amounts order by March 21, 2011. Board staff and intervenors shall respond to OPG’s draft payment order by March 28, 2011. OPG shall respond to any comments by Board staff and intervenors by April 4, 2011.

14.2 Cost Awards

A number of intervenors were deemed eligible for cost awards in this proceeding: Association of Major Power Consumers in Ontario, Canadian Manufacturers & Exporters, Consumers Council of Canada, Energy Probe Research Foundation, Green Energy Coalition, Pollution Probe, School Energy Coalition and Vulnerable Energy Consumers Coalition.

A cost awards decision will be issued after the steps set out below are completed.

ONTARIO POWER GENERATION

File No: N-REP-00120.3-10001-R000

Project ID - 16-27959

Darlington Refurbishment
Execution Phase
Business Case Summary

November 13, 2015

OPG Confidential & Commercially Sensitive

Contents

DARLINGTON REFURBISHMENT BUSINESS CASE SUMMARY

1. RECOMMENDATION:

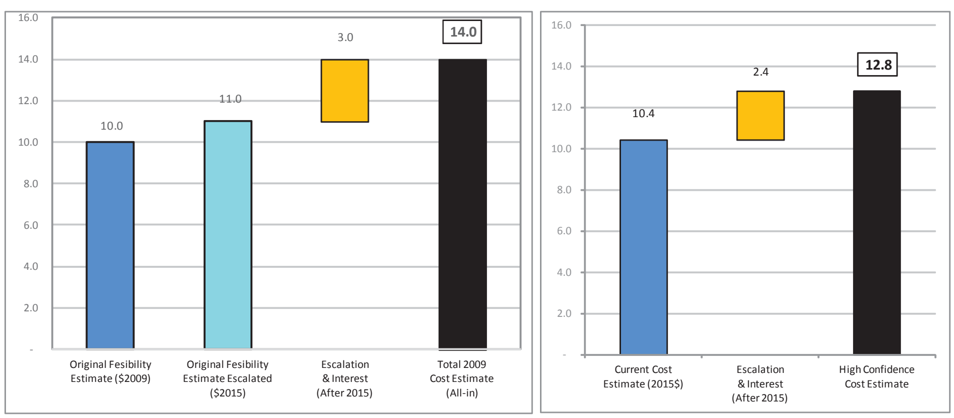
In 2009, OPG's Board of Directors (the Board) approved the Economic Feasibility Assessment and the Business Case Summary (BCS) related to the refurbishment of the Darlington Nuclear Generating Station. The Board approved the project and released funds to commence preliminary planning within the Definition Phase in accordance with the Darlington Refurbishment Program's (DRP) release strategy. The Board also approved the release of funds in November 2011, November 2012, November 2013 and November 2014 to complete detailed planning activities within the Definition Phase.

The purpose of this Release Quality Estimate BCS is to provide: a) a 4-Unit cost and schedule estimate (the "RQE"); b) an update on the status of the DRP; c) an update on the economics of the DRP; and (d) to request funding to complete preparation of execution activities on Unit 2, and other critical 2016 planned deliverables related to subsequent units. The current target date to start the Refurbishment outage on Unit 2 is October 2016, prior to which management will complete a Unit 2 Execution estimate and seek further authorization and funding approval from the Board.

In 2009, management communicated to the Board that the project cost would be less than $10B in 2009$ which is equivalent to $11.0B in 2015$ excluding capitalized interest and inflation. Including capitalized interest and inflation, the 2009 estimate is $14B.

Management has completed the Definition Phase has high confident that the 4-unit cost estimate is $10.4B (2015$). The $10.4B (2015$) estimate is $12.8B including capitalized interest and future inflation. Life to date expenditures (to the end of December 2015) are forecast at $2.2B (including interest and inflation), leaving $10.6B remaining to be expended on the project. Figure 1 below provides a comparison of the RQE compared to the bounding estimate communicated in 2009.

Figure 1: Refurbishment RQE Compared to 2009 Promise of Less Than $10B 2009$



Original Feasibility Estimate
($ Billion)

4-Unit Cost Estimate
($ Billion)

At a cost of $10.4B (2015$), the Levelized Unit Energy Cost ("LUEC") of refurbishing and continuing to operate the Darlington units for a further 30 years is estimated to be 8.1 ¢/kWh (2015$). This LUEC is based on the RQE of the DRP (which is a high confidence estimate) and high confidence estimates of the post-refurbishment operating costs and performance. In 2010, OPG publicly communicated that the economic LUEC would be less than 8 ¢/kWh in 2009$, which is equivalent to 9.0 ¢/kWh in 2015$. Thus, OPG's current LUEC estimate of 8.1 ¢/kWh (2015$) for the DRP is well within the bounding estimate, publicly communicated by OPG in 2010.

The LUEC of refurbishing the Darlington Station indicates that Darlington would provide a stably-priced, low cost generation option for Ontario for the future 30 to 35 years.

DARLINGTON REFURBISHMENT BUSINESS CASE SUMMARY

Other considerations which contribute to and support the favourable economic assessment for refurbishing the Darlington Station include:

- The use of an existing generation site, with a proven environmental record and a supportive host community, avoids the additional costs to OPG (and ratepayers) of site selection, securing environmental approvals and development of host community support at an unproven greenfield or brownfield site. It also avoids the additional costs to ratepayers of establishing new transmission infrastructure.
- Economic benefits of refurbishing the Darlington Station, in terms of direct, indirect and induced job creation. Between 2016 and 2025, the Conference Board of Canada estimates that the DRP's construction phase alone is expected to generate $14.7B in economic benefits to Ontario. At its peak, the DRP will create 11,700 jobs per year, with an average of 8,700 annually between 2014 and 2013. It will also increase household revenues in Ontario by $8.5B and government revenues by $5.5B.

As a result of OPG's improving confidence in the life of critical components at the Darlington Station and the resulting opportunity created to maximize the value of the asset and smooth the overall rate impact while mitigating execution risk of the DRP, management recommended the removal of the overlap of the first and second refurbishment units in June, 2013. This recommendation effectively delays the beginning of the refurbishment outages on the 2^{nd}, 3^{rd} and 4^{th} units nominally, by 18 months each. This schedule change was approved by the Chief Executive Officer ("CEO") and formed the base schedule planning assumption for this BCS. With the RQE and schedule, it remains that OPG will execute the refurbishment of the 4 Darlington Units with no overlap of the first two units, but with approximately 50% overlap of the remaining 3 units. Management will continue to explore opportunities to optimize the schedule based on remaining station life and economics.

Management is seeking a partial release in the amount of $681M to prepare for the execution of Unit 2 in 2016 (Release #5a) and to complete other critical 2016 planned deliverables related to subsequent units. The total cumulative funds released to the project, including this release, will total $3,228M including capitalized interest, inflation, and contingencies.

Management, in planning for the DRP, has negotiated contracts that limit OPG's exposure should a decision be made not to continue the DRP. Based on the amount of work currently in progress, should a decision be made not to continue the DRP, the currently committed cost to close the project, including demobilization of project staff and cancellation of existing contracts, material orders, etc., is estimated to be $150M. Management is not requesting a release of funding for demobilization costs with this release.

Key activities, as defined in Appendix D, to be completed in 2016 include:

- Procurement activities including the fabrication and delivery of reactor components for Unit 2
- Progression of refurbishment pre-requisite work including construction of facilities and infrastructure projects, safety improvement projects (e.g. 3^{rd} Emergency Power Generator, Containment Filtered Venting System) and other pre-requisite work such as the Re-tube Waste Processing Building
- Execution of pre-breaker open work to support Refurbishment and Integrated Improvement Plan (IIP) commitments (e.g. unit islanding modifications, service modifications such as breathing air and temporary power, and turbine crane overhaul)
- Overall planning support to the projects including establishment of the construction organization, work instruction development and review, and permitry and radiation protection planning

ONTARIO POWER GENERATION

November 2015

File: P-BCS-00970-0001 REV: 000

Reviews and Approvals

Name	Title	Action	Signature	Date
B. McGee	Senior Vice President - Pickering	Review		
L. Swami	Senior Vice President – Decommissioning & Nuclear Waste Management	Review		
P. Pasquet	Senior Vice President	Review		
S. Woods	SVP and Chief Nuclear Engineer	Technical Concurrence		
C. Carmichael	Vice President – Nuclear Finance	Financial Review		Nov 10/15
A. Barrett	Vice President – Regulatory Affairs	Regulatory Review		
G. Jager	President, OPG Nuclear and Chief Nuclear Officer	Recommend BCS	Please sign on Executive Summary	
B. Summers	Chief Financial Officer	Finance Approval	Please sign on Executive Summary	Nov11, 2015
J. Lyash	President & CEO	Approval	Please sign on Executive Summary	Nov 12, 2015

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ONTARIO POWER GENERATION

November 2015

File: P-BCS-00970-0001 REV: 000

Technical and Economic Assessment of Pickering Extended Operations beyond 2020

October 2015

Contents

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EXECUTIVE SUMMARY:

RECOMMENDATIONS:

1. Extended Operations of all six Pickering Units beyond the end of 2020 shows economic value and qualitative benefits to OPG and the Ontario electricity system. Based on this assessment, operation of two units to nominally 2022 and the remaining 4 units to nominally 2024 is recommended.
2. OPG should continue working to provide improved certainty associated with implementation of the Preferred Extended Operations Alternative by refining the extended operations targeted ends-of-life for each unit as greater certainty becomes available regarding the technical fitness-for service of the fuel channels in each of the units.
3. The incremental costs to enable Extended Operations are estimated at approximately \$310M. It is recommended that \$52M (including \$5M contingency) be released in order to complete the Periodic Safety Review, the Fuel Channel Life Assurance Project and to execute incremental outages and inspections in 2016 and 2017. Management will seek a full release following confirmation of the fuel channel life of the units and completion of the Periodic Safety Review.

OPG's planning assumption for the 2015-2017 Business Plan had all six of the Pickering units shutting down at the end of 2020. OPG has been working with the IESO and the Ministry of Energy to explore options to extend operations beyond 2020. Preliminary technical and economic assessments have been undertaken that demonstrate that extending operations would be safe, is technically feasible and would have economic and qualitative benefits. Extending the life of Pickering would also optimize the value of OPG's existing assets, improve OPG's financial position and mitigate Ontario electricity system capacity uncertainties during Darlington and Bruce Refurbishment outages in the early 2020s. This business case summarizes the status of the technical and economic feasibility assessment of continuing to operate the Pickering Units for 2-4 years after 2020.

In the fall of 2014 and early 2015, OPG assessed a number of alternatives for extending the operation of Pickering beyond the end of 2020. Data was provided to the IESO in December 2014 and again in October 2015 to facilitate the completion of an independent system economic value analysis. The Ministry of Energy was periodically briefed on the status of the assessments.

Based on the assessments completed by OPG and independently by the IESO, the preferred alternative of operating six units to 2022 and four units to 2024 was selected in the spring of 2015. This alternative, herein called the **Preferred Alternative** is summarized in Table E1 below:

Table E1: Preferred Alternative Selected

Preferred Alternative			
P1 & 4 (End of)	P5-8 (End of)	Assumed VBO (*)	Comments
2022	2024	2021	High Confidence in Fuel Channel life assumed to be achieved to the end of 2024 for P5-8. Preferred alternative from a system value perspective.

OPG has assessed the incremental generation associated with the Preferred Alternative. Incremental generation is the amount of generation over and above that which would have been achieved in the Base Case of operation to 2020. OPG's economic assessment shows that the value to the Ontario electricity system ranges from \$0.5 Billion to \$0.6 Billion.

In addition, OPG has assessed numerous benefits including reduced OPG nuclear rates, financial benefits, deferral of severance and related costs, and deferral / reduction of nuclear rate spikes associated with the shutting down of Pickering and placing the refurbished Darlington units in service. Extending Pickering operations would improve OPG's cash flow by $4 Billion from 2021 to 2024 compared to the alternative of shutting down in 2020 and assumes that OPG implements a rate smoothing deferral account. Extending Pickering operations also provides incremental net income to OPG. Extension of the Pickering plant to 2022/2024 would allow OPG to execute the job reductions associated with the shutdown at or near the end of the Darlington Refurbishment Project, thereby reducing the amount of disruption such a large downsizing could potentially have on that project.

The incremental costs to enable the Preferred Alternative have been estimated at approximately $310M. Incremental costs incurred from 2016-2020 to enable extended operations are required to execute work programs that will allow Pickering to operate beyond 2020. These costs would not have been required in the base case if Pickering was shutting down in 2020. There are also incremental costs required to restore on-going operating programs to normal levels of spending prior to and including 2020. For example, planned outages eliminated in 2020 as part of the base case would now need to be restored as part of normal operating practice. Finally, costs from 2021-2024 reflect normal operating costs for that period of time. Costs are summarized in Table E2.

Table E2: Estimated Incremental Costs to Enable Extended Operations

Work Program	2016 - 2020 ($M)	Post 2020 ($M)	Totals ($M)	Comments
Normal Extension of Base & Outage OM&A, Projects, Nuclear and Corporate Support Costs	240	4,220	4,460	Restoring resources to normal levels pre-2020 and costs to operate post-2020
Total Costs to Enable Extended Operations Alternative	310	0	310	Incremental work program costs required to enable extended operations
Grand Total	**550**	**4,220**	**4,770**	

A partial release of $52M (including $5M contingency) would cover the costs of incremental work programs required in 2016 and 2017 to extend operations including the Fuel Channel Life Assurance Project, the Periodic Safety Review and incremental inspections and maintenance work required to demonstrate fitness for service of major components during the extended operations period.

The normal costs to operate the station into the Extended Operations period are estimated at $4.5B. This includes approximately $240 Million leading up to 2020 to restore work program costs which were set to decline in the Base Case, plus $4.2B to operate and provide support services to the plant in the post-2020 period.

Table E3 summarizes the generation forecasts developed for the extended operations Preferred Alternative.

Table E3: Estimated Generation Impacts of the Preferred Alternative

Generation Plan		2016 - 2020	Post 2020	Total
OPTION 1	Additional Planned Outage Days	630	1,103	**1,734**
	Incremental TWh	-7.4	71.9	**64.5**
OPTION 2	Additional Planned Outage Days	637	1,354	**1,991**
	Incremental TWh	-7.5	68.9	**61.5**

The additional outage days in the period 2016 to 2020 are associated with incremental inspections required to enable the Preferred Alternative as well as restore normal planned outages and durations in 2020. In the Base Case (planned shutdown in 2020) certain planned outages in 2020 would not have been necessary or would have been reduced in scope.

The planned outage days in the period 2021 to 2024 are associated with operation of the units for the additional 2 and 4 calendar years (a total of 20 additional unit-years). The two options reflect the range of outcomes required to execute inspection and maintenance activities necessary to maintain fitness for service of plant equipment.

The "medium" to "high" risks associated with the Preferred Alternative are summarized below:

1. Reputational Risk (High): e.g. the risk that interest groups that are opposed to nuclear power will contest Extended Operations, particularly during the next license renewal process, and thereby cause increased community concern and potential earlier shutdown than planned. *Mitigating Actions:* Ongoing demonstration of the value and safety of Pickering through external communications, hearings and stakeholder relations.
2. Regulatory Risks (Medium): e.g. the risk that the proposed disposition for one or more known issues is not accepted by the CNSC. *Mitigating Actions:* Completion of the PSR and a pro-active approach with the CNSC to demonstrate technical fitness-for-service and maintenance of high safety standards.
3. Technical/Fitness-for-Service Risks (Medium): e.g. the risk that a major component, e.g. fuel channels, does not continue to meet fitness-for-service requirements. *Mitigating Actions:* On-going comprehensive inspection and maintenance programs are included in the work program; life cycle management program of major components adjusted based on the extended end-of-life dates.
4. System Value Assessment (Medium) – changes to Ontario system parameters such as flat or declining load growth, reduction in the cost of competing generation or changes to baseload supply (e.g. refurbishment schedules changes) could impact the overall economic system value negatively. *Mitigating Actions:* None that OPG can implement directly. Robust analysis across a range of scenarios and OPG ensuring that costs and generation forecasts are achieved.

Management assesses the risks associated with the extended operations Preferred Alternative to be manageable.

Management recommends that funding of $52M be released in order to complete the Periodic Safety Review, the Fuel Channel Life Assurance Project and to execute incremental outages and inspections in 2016 and 2017. Management will seek a full release following confirmation of the fuel channel life of the units and completion of the Periodic Safety Review.

SIGNATURES

Recommended by:

11 Nov 2015

Glenn Jager Date
President OPG Nuclear & Chief Nuclear Officer

Finance Approval:

Nov 11, 2015.

Beth Summers Date
Chief Financial Officer

Line Approval per OAR Element 1.3:

Nov 12, 2015

Jeff Lyash Date
President & Chief Executive Officer

BACKGROUND:

OPG's planning assumption for the 2015-2017 Business Plan had all six of the Pickering units shutting down at the end of 2020. OPG has been working with the IESO and the Ministry of Energy to explore options to extend operations beyond 2020. Preliminary technical and economic assessments have been undertaken that demonstrate that extending operations would be safe, technically feasible and would have economic and qualitative benefits. Extending the life of the Pickering GS would also optimize the value of OPG's existing assets, improve OPG's financial position and mitigate Ontario electricity system capacity uncertainties during the Darlington and Bruce Refurbishment outages in the early 2020s. This business case summarizes the status of the technical and economic feasibility assessment of continuing to operate the Pickering Units for 2-4 years after 2020, and outlines the work programs, costs, generation impacts and benefits of implementing the Preferred Alternative.

ALTERNATIVES ANALYSED

As summarized in Table 1, five Extended Operations alternatives were assessed at a conceptual level in addition to the current planning reference of operating all six units to the end of 2020.

Table 1: Pickering Extended Operations Alternatives Analysed

Case	Description			
	P1 & 4 (End of)	**P5-8 (End of)**	**Assumed VBO (*)**	**Comments**
Base	2020	2020	None	Base Case for 2015 to 2017 Business Planning was 2020 Shutdown of all units.
Alt 1	2022	2022	None	Fuel Channel Life assumed sufficient to achieve the end of 2022 without life management. Not preferred from a rate impact and system value perspective.
Alt 2	2022	2024	2021	High Confidence in Fuel Channel life assumed to be achieved to the end of 2024 for P5-8. Preferred alternative from a rate impact and system value perspective.
Alt 2LM	2024	2024	2021	Fuel Channel Life constraints would require life management on two units to achieve the end of 2024. Lower value to system than preferred alternative. Rate in early period due to life management and rate spikes than in Alternative 2
Alt 3A	2024	2024	2021	Low technical confidence that all six units could operate to the end of 2024
Alt 3B**	P1 2022 P4 2024	2024	2021	Potentially high operating costs for Unit 4 without Unit 1. Future option may be enabled after further analysis.

* A Vacuum Building Outage is assumed in 2021 for all alternatives where units operate beyond 2022.

** This alternative was assessed at a high-level only. The current assumption is that the alternative will be technically viable. However, the cost of operating P4 in the absence of P1 needs to be assessed in more detail.

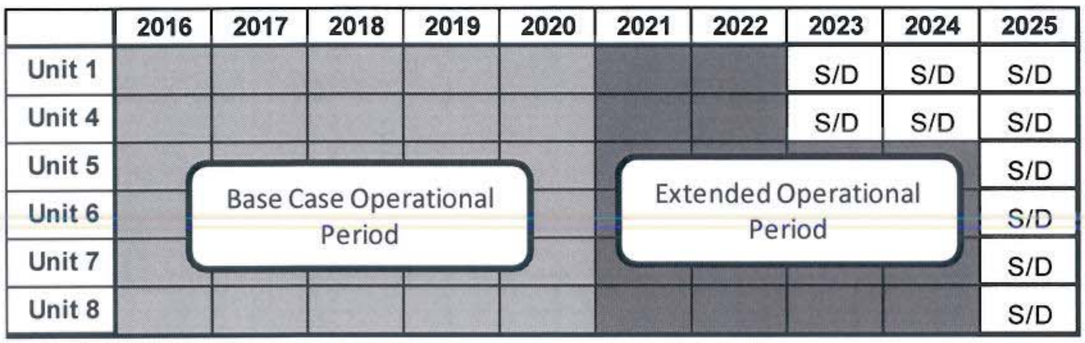
The IESO was provided with data on the above alternatives in December 2014 in order to facilitate an independent system economic value analysis. Based on the assessments completed by OPG and independently by the IESO, the preferred alternative of operating six units to 2022 and four units to 2024 was selected in the spring of 2015. This alternative is referred to as the **Preferred Alternative** in the remainder of this document.

Table 2: Preferred Alternative Selected

P1 & 4 (End of)	P5-8 (End of)	Assumed VBO (*)	Comments
2022	2024	2021	High Confidence in Fuel Channel life assumed to be achieved to the end of 2024 for P5-8. Preferred alternative from a rate impact and system value perspective.

Figure 1 shows a schematic of the remaining operational period of the Pickering units in the Base Case and the period over which the units would be operated in the Preferred Alternative.

Figure 1: Schematic showing "Base Case" and Preferred Extended Operations Alternative



S/D = shutdown

PICKERING SAFE OPERATION

To assure management that the plant is and will continue to be safe in the future, there are ongoing assessments of the condition of plant equipment. When the plant is operated beyond its original design life, the assessment of the condition of the major components such as fuel channels, feeders and steam generators is most important. This is done through an extensive inspection program during planned outages. The required inspections and maintenance of components is specified in life cycle management plans which are used to determine that the plant components are fit for their intended service.

At the end of outage inspections, fitness-for-service assessments are completed to confirm that the components are able to function as designed until the next inspection campaign. If the assessments cannot demonstrate that component condition is acceptable, the component will be replaced or repaired. If the work required is significant, management may determine that the unit is no longer able to continue to operate. The frequency of inspections and assessments is such that this determination would be made and a decision would be taken long before component failure, thereby preventing any nuclear safety event.

The fitness-for-service assessments are also independently reviewed by staff from the Canadian Nuclear Safety Commission and, if warranted, OPG would be requested to take appropriate action to address any issues.

TECHNICAL ASSESSMENT SUMMARY

An initial technical assessment of the ability of the Pickering units to continue to be fit for service to the dates set out in the Preferred Alternative has been completed. The scope of work required to develop high confidence in the fitness-for-service to these dates has been identified. As expected, the limiting major component is the life expectancy of the fuel channels.

Technical assessment work on the fuel channels' fitness-for-service will continue through the Fuel Channel Life Assurance Project with the aim of completing a high confidence prediction of fuel channel fitness-for-service on all units by the end of 2017.

The technical fitness for service of other major components such as the Steam Generators, is not considered life limiting; however, additional inspection and maintenance scope is required to assure fitness-for-service to the dates in the Preferred Alternative. This additional work has been identified; impacts on the generation plan developed and the costs are included in the forecasts.

Fuel Channels:

The technical assessment has identified that the major concern is axial elongation of the pressure tubes. A number of channels are expected to reach the limits of available bearing travel (i.e. when the leading pressure tubes will no longer be supported on their bearings), with Units 1 and 6 being of greatest concern.

Table 3 summarizes the current confidence level for operation to 2024 for all units.

Table 3: Current Level of Confidence in Operation to 2022/2024 – All Units

Unit	Current Confidence for Operation to 2022/2024	Comments
Unit 1	Low	Current projections indicate potential for channels off-bearing by 3rd Quarter 2021
Unit 4	High	Operation to 2024 is possible technically based on pressure tube degradation mechanisms
Unit 5	Medium	Current projections indicate potential for channels off-bearing by late 2022/early 2023
Unit 6	Low	Current projections indicate potential for channels off-bearing by mid-2022
Unit 7	Medium	Current projections indicate potential for channels off-bearing by late 2022/early 2023
Unit 8	High	No channels projected off bearing to end of 2024

Several mitigation measures are available for pressure tube elongation. These include physical modifications as well as more detailed technical evaluations to refine assessments of the timing and number of channels which would approach limits of bearing travel on each unit. Some of the physical modifications which are available would be costly to implement and some of the technical solutions are complex and/or would require increasing the complexity of operational procedures. Therefore, the preliminary plans to enable the Preferred Alternative include only the less costly physical modifications and less complex technical evaluations. However, the remaining mitigation options have not been ruled out and will be assessed as part of the Fuel Channel Life Assurance Project. The costs of the Fuel Channel Life Assurance Project are covered in the partial release requested in this Business Case.

Currently, pending more detailed review and development of mitigation plans, Units 1 and 6 would be challenged to meet the end dates in the Preferred Extended Operations Alternative. Two other units, Units 4 and 8, are assessed to be able to surpass the planned end of operation dates, if necessary

Unit 1 is challenged by available bearing travel in order to achieve the end of 2022 in the Preferred Alternative. However, with expected mitigation, operation of Unit 1 into mid-to-late 2022 is likely. Further mitigation would be required to enable Unit 1 to operate to the end of 2022. A final determination of the shutdown date of Unit 1 will be dependent on the results of the Fuel Channel Life Assurance Project.

Unit 6 is challenged by available bearing travel to achieve the target date of the end of 2024 in the Preferred Alternative. However, with mitigation, there is a potential to operate Unit 6 into mid-to-late 2023 and even into 2024. Confidence in operation to the end of 2024 is low at this time. Unit 6 may be replaced by Unit 4 as one of the four units operating to the end of 2024, depending on economics and the outcome of the technical analysis.

Units 5 and 7, based on current projections of available bearing travel, would have a minimal number of channels projected to be off-bearing by late 2022/early 2023 but with mitigation can be operated longer. Confidence in operation to the end of 2024 is medium to high at this time.

Unit 4 does not face the same issues with available bearing travel as Unit 1; therefore, confidence in operation until the end of 2022 is currently high. There is a potential that the Preferred Alternative may evolve to have Unit 4 replace Unit 6 as one of the four units operating to 2024.

Unit 8, having been the last unit to be placed in-service, has the lowest operational service life of Units 5-8, and is not projected to reach available bearing travel limits before the end of 2024; therefore, confidence in operation until the end of 2024 is currently high.

As mitigation plans are developed in more detail, the Preferred Alternative may be refined with more precise end-of-operation target dates for each unit.

In addition to pressure tube elongation, other fuel channel degradation mechanisms are of concern, but are not seen as limiting the operation of the units in the Preferred Alternative. Table 4 lists some of the concerns:

Table 4: Fuel Channel Risks Associated with Operation of P1&4 to 2022 and P5-8 to 2024

Mechanism	Concerns	Level of Concern	Potential Mitigation
Pressure Tube (PT) Elongation	**P1** Up to 43 channels off-bearing by end 2022 if no add'l mitigation	**High**	• **Physical**: Reconfigure and Shift fuel channels • **Analytical:** Evaluations to disposition operation with a limited number of channels off-bearing
	P6 Up to 78 channels off-bearing by end 2024 if no add'l mitigation	**High**	
Calandria Tube (CT) Sag P1/4 **CT to LISS[(1)] Nozzle contact P5-8**	**P1 & 4** – potential for PT to CT contact given detensioning of tight fitting spacers. CTs were not replaced during retube, and modeling is not currently possible	**Medium**	• **Inspection**: Additional measurements and sampling to demonstrate low probability of PT to CT contact and hydrogen concentration below specified levels. • **Analytical**: Disposition likelihood of channels exceeding operational limits
	P5-6: Potential for ~10 channels to contact with LISS nozzles by end 2024	**Medium**	• **Inspection:** Repeat measurements could yield increased margins • **Physical:** Potential need to replace individual fuel channels
Pressure Tube Fracture Toughness	Potential to exceed fracture toughness thresholds	**Low**	• **Analytical:** Work underway to develop updated fracture toughness curves for P1& 4 & P5-8 – small potential for station modifications

(1) LISS – Liquid Injection Shutdown System – these nozzles extend horizontally into the reactor core and could come into contact with calandria tubes late in life on certain units, resulting in concerns regarding calandria tube integrity.

Steam Generators and Feeders:

Preliminary assessments indicate that steam generators and feeders do not present a significant hurdle for proving fitness-for-service of the units. Steam generators are not expected to show any significant degradation in performance provided that maintenance (water-lancing) and inspection campaigns are extended appropriately for each of the extended life scenarios. Similarly, a limited number of feeder replacements are required on Units 5-8 in order to operate to 2024.

Balance of Plant:

Balance of plant components, including the turbine-generator sets, the condensers, heat exchangers and major motors have also been assessed based on current system health reports and previous condition assessments, and no significant issues have been found which would preclude operation to 2024. Normal maintenance activities would continue in the Extended Operations period. Condition assessments are being updated based on a 2024 end-of-life date. The cost of this work is included in the Partial Release requested in the Business Case.

REGULATORY APPROVALS

In addition to component fitness-for-service uncertainties, the Preferred Alternative of extending operations will require concurrence by the CNSC. The current power reactor operating licence for Pickering was issued in September 2013 for a 5 year term (expiring in 2018). The license included a requirement that OPG confirm, in writing, by June 30, 2017 the planned end-of-life date for Pickering. OPG expects to provide that confirmation with the licence application for the next operational period. OPG's strategy will be to secure a 10-year licence renewal which will take the units to the end of commercial operations and through the safe storage project period, i.e. until the units are in the safe stored state. CNSC concurrence with operation beyond 2020 will occur in the context of the Pickering licence renewal in 2018.

OPG has determined, based on discussions with the CNSC, that an update to the Periodic Safety Review (PSR) will be required in advance of the 2018 Re-licensing Hearings if OPG plans to extend operations beyond 2020. The PSR, which is already underway, will confirm that extending operations of the Pickering units will be safe to the public, workers and the environment. Management has scheduled completion of the PSR by the end of 2016, such that the information confirming that Pickering is safe to operate will be available prior to the decision on the permanent shutdown dates of the Pickering units and the required formal communication of that decision to the Commission by June 30, 2017.

A Periodic Safety Review evaluates an existing plant and the programmes used in its operation against the modern standards that would apply to a new nuclear plant. The evaluation may identify where, on a going forward basis, enhancements to the current design or programmes could be made. The potential safety enhancements are then assessed to identify the alternatives that can be reasonably and practicably implemented to improve safety, if any, in the context of 4 years of additional operations. There is a medium risk that the results of this updated assessment may require physical modifications to be implemented to the plant.

A key to risk mitigation for OPG will be establishing with certainty the regulatory requirements and how these interrelate to the timing of the end of extended operations, as well as maintaining openness and establishing good lines of communication with all key stakeholders.

Management is confident that a list of reasonable and practicable safety enhancements can be reached with the CNSC staff in view of the 4 years of additional operation that is sought.

STAFFING

On-going staffing risks will continue to require close management attention in order to ensure safe operation in the Preferred Alternative. For example, the sufficiency of authorized operators and control room shift supervisors has been assessed and costs have been included in the forecast to extend planned training programs for authorized staff to ensure an adequate supply. Because of the criticality of these resources to safe operations, on-going reviews will continue as part of Business and Operational Planning.

Leadership development and succession planning will be revisited with a view to ensuring that leadership will be available for the extended operation period.

COSTS AND GENERATION ASSUMPTIONS

In developing the Preferred Alternative, OPG's objective is to establish with medium to high confidence the appropriate incremental work and related costs over and above those costs included in the Base Case required to enable the extended operations. OPG's approach is summarized in the following 8 steps:

1. Resources and associated costs (Base OM&A, Outage OM&A, Projects, Nuclear and Corporate Support) are continued at normal levels during the extended operation period.
2. Additional inspections and maintenance scope for major components (fuel channels, steam generators, feeders and reactor components) are identified in detail and the impacts on outage durations and costs (primarily fuel channel inspections and maintenance) are assessed.

3. Additional "Balance of Plant" scope is identified, estimated and the impact on outages and costs (if any) are assessed.
4. Additional sustaining investments (Capital and OM&A projects) are identified, and impacts on outages and costs (if any) assessed.
5. Additional analytical scope (primarily regulatory and engineering) is identified and costs and resources estimated
6. Any other additional enabling scope (e.g. staff retention costs) is identified and estimated
7. Nuclear Support and Corporate Support costs are assessed
8. Amounts are estimated to address known uncertainties

Based on the above assessments, the costs and outage impacts have been estimated and included in the assessment of the Preferred Alternative. Also, amounts have been included to fund the Period Safety Review and any potential modifications resulting from that review.

The incremental costs to enable the Preferred Alternative have been estimated approximately $310M. Incremental costs incurred from 2016-2020 to enable extended operations are required to execute work programs that will allow Pickering to operate beyond 2020. These costs would not have been required in the base case if Pickering was shutting down in 2020. There are also incremental costs required to restore on-going operating programs to normal levels of spending prior to and including 2020. For example, planned outages eliminated in 2020 as part of the base case would now need to be restored as part of normal operating practice. Finally, costs from 2021-2024 simply reflect normal operating costs for that period of time. Costs of the Preferred Alternative are summarized in Table 5.

Table 5: Summary of Costs - Preferred Alternative

Work Program	2016 - 2020 ($M)	Post 2020 ($M)	Totals ($M)	Comments
Normal Extension of Base & Outage OM&A, Projects, Nuclear and Corporate Support Costs	240	4,220	4,460	Restoring resources to normal levels pre-2020 and costs to operate post-2020
Total Costs to Enable Extended Operations Alternative	310	0	310	Incremental work program costs required to enable extended operations
Grand Total	**550**	**4,220**	**4,770**	

Additional details associated with the costs to enable the Preferred Alternative are provided in Appendix 1.

Table 6 summarizes the generation forecasts developed for the extended operations Preferred Alternative.

Table 6: Estimated Generation Impacts of the Preferred Alternative

Generation Plan		2016 - 2020	Post 2020	Total
OPTION 1	Additional Planned Outage Days	630	1,103	**1,734**
	Incremental TWh	-7.4	71.9	**64.5**
OPTION 2	Additional Planned Outage Days	637	1,354	**1,991**
	Incremental TWh	-7.5	68.9	**61.5**

The additional outage days in the period 2016 to 2020 are associated with incremental inspections required to enable the Preferred Alternative, as well as restore normal planned outages and durations in 2020 that would have been reduced or not necessary in the Base Case (planned shutdown in 2020).

The planned outage days in the period 2021 to 2024 are associated with operation of the units for the additional 2 and 4 calendar years (a total of 20 additional unit-years). The two options reflect the range of outcomes required to execute inspection and maintenance activities necessary to maintain fitness for service of plant equipment.

ECONOMIC ASSESSMENT SUMMARY

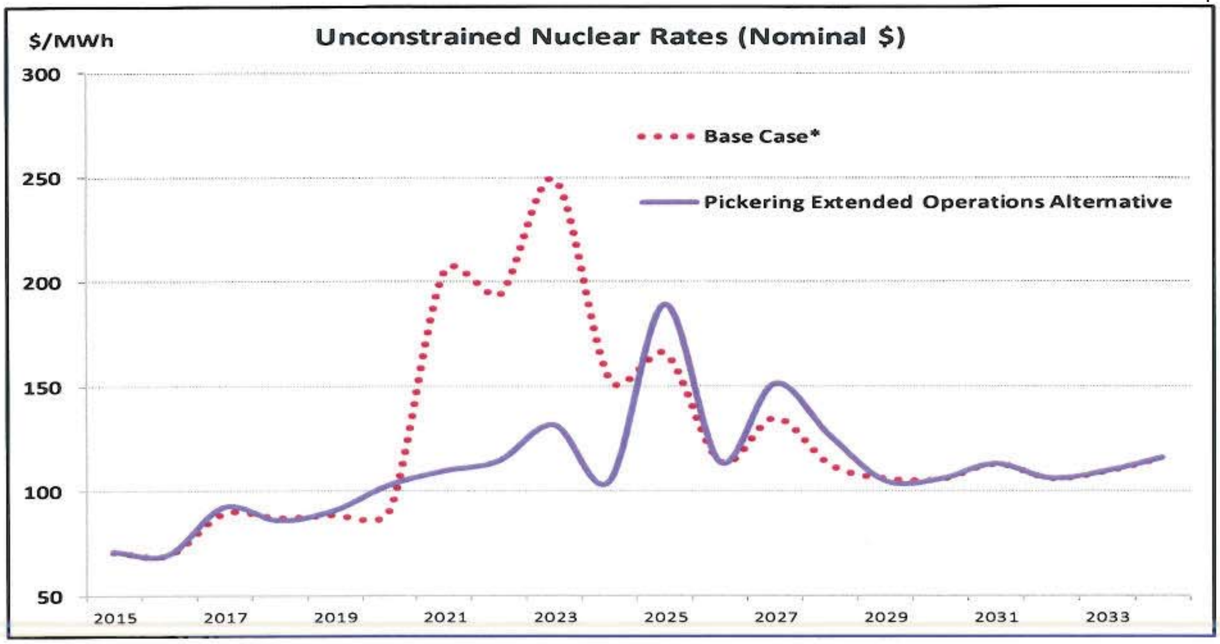
The Levelized Unit Energy Costs (LUEC) of the Preferred Alternative, i.e. the LUEC associated with the incremental costs and generation relative to the Base Case, is evaluated at 6.2 ¢/kWh to 6.5 ¢/kWh for the two options. LUEC calculations exclude the benefit of deferring severance and related costs.

The Preferred Alternative also provides a number of quantitative economic advantages for both the ratepayer and OPG. The major economic advantages are:

- **Financial Impacts:** Extending Pickering operations would improve OPG's cash flow by $4 Billion in the 2021 to 2024 period compared to the alternative of shutting down in 2020 and assuming that OPG implements a rate smoothing deferral account. Extending Pickering operations also provides incremental net income to OPG.

- **Rate Impacts:** Figure 2 shows the impact of the Preferred Alternative on OPG Nuclear rates. Extending Operations moderates the rate impacts associated with the refurbishment and return to service of the Darlington units and the earlier shutdown of Pickering which would occur in the Base Case. This occurs because extending Pickering Operations results in a larger OPG generation base over which to spread the impacts of the Darlington Refurbishment costs being placed into the rate base and because the severance and related closure costs of Pickering would be deferred.

Figure 2: OPG Nuclear Rate Impacts of Preferred Alternatives



*Note: These rate projections do not yet include finalized assumptions regarding Darlington Refurbishment Costs; however no material change is expected to these rate curves.

- **Severance and Related Costs:** Defers costs associated with closure of the station, such as severance and related costs, and pension curtailment and settlement resulting in a potential reduction in the present value of the severance and related costs. While there is significant uncertainty around these costs the deferral of these costs by 4 years, even if there is no change in the nominal value, would results in present value savings. Demographic changes by the end of Extended Operations could result in a reduction of the estimate of severance costs, potentially resulting in higher estimated Present Value savings.

- **Decommissioning Liability:** Defers expenditures associated with placing the units in the safe-stored state, and the assumed deferral of the expenditures associated with dismantling of the units. The effect is to reduce the liability associated with decommissioning of the Pickering station. This value is considered by the IESO in its assessments.

- **System Economic Value:** For the Ontario system, extended operation of Pickering would mitigate capacity availability uncertainties associated with the refurbishments of the Darlington and Bruce stations. Availability of Pickering would reduce the need to operate gas-fired capacity and would result in reduced CO_2 emissions over the 2021 to 2024 period. OPG's assessment of the median value to the Ontario electricity system of the Preferred Alternative, relative to the Base Case is summarized in Table 7.

Table 7: System Economic Value – Preferred Alternative P1& 4 S/D 2022; P5-8 S/D 2024

Generation Plan	Net Incr. Energy (TWh)	CO_2 Red'n (MT)	Med. System Economic Value (2015$M NPV)	Comments
OPTION 1	65	~18	610	System value is higher because of the assumed higher generation from 2021-2024.
OPTION 2	62	~16	530	

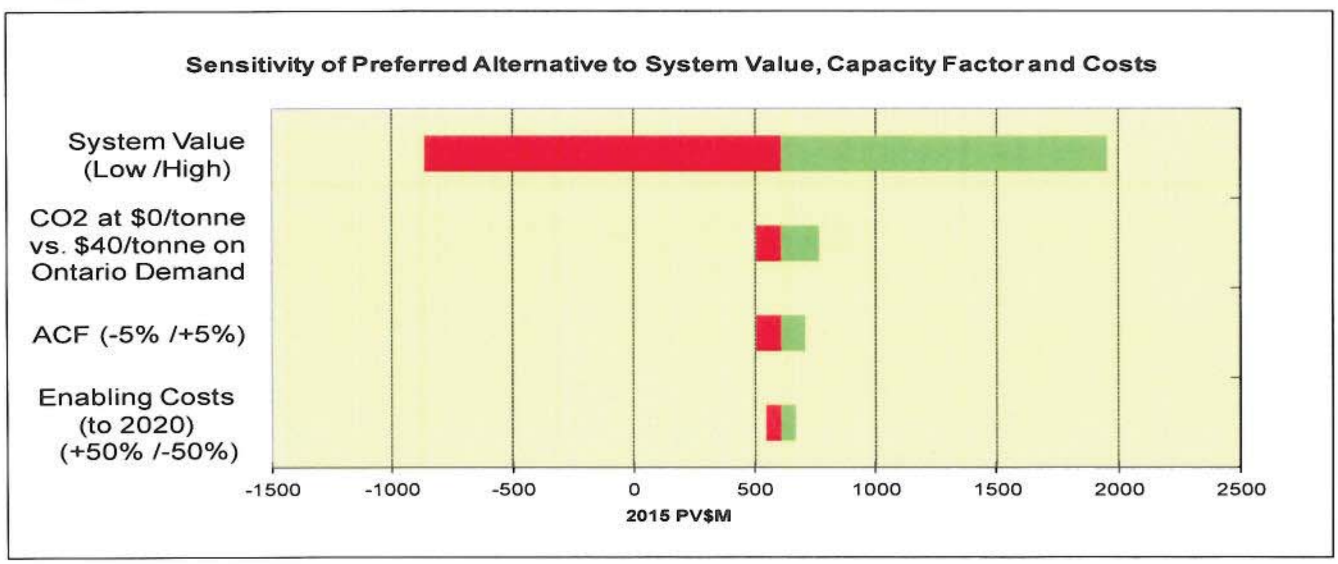
The values in Table 7 include a benefit of $245M (2015 PV$) associated with the reduced present value of severance and related costs. Also includes is a benefit of $100M representing the value of the reduction in the decommissioning liability as a result of the deferral in the decommissioning expenditures.

The IESO has completed an updated assessment using data provided by OPG in October 2015. The assessment shows a benefit ranging from ~$0.3 Billion (2015 PV$) to ~$0.5 Billion (2015 PV$). The IESO's assessment, therefore closely corresponds to OPG's internal assessment. The IESO uses a lower real discount rate (4% vs. OPG's approx. 5%) and different system assumptions (e.g. for load growth and the price of gas-fired generation).

Figure 3 shows the sensitivities of the system economic value for OPTION 1 to uncertainties in the system energy and capacity value, the performance and the incremental costs to enable the Preferred Alternative, and the value of carbon reduction.

The system economic value of the Preferred Alternative is significantly more sensitive to system assumptions than to the costs and performance of Pickering.

Figure 3: Sensitivity of System Economic Value (PLAN 1) to Changes in Assumptions



QUALITATIVE CONSIDERATIONS

The following qualitative considerations associated with Extended Operations are of significant potential value to OPG and Ontario:

- **Deferral of Job Losses:** Would defer direct job losses of approximately 4,000 in OPG, affecting the GTA and Durham Region; there would also be impacts on indirect and induced jobs and the economy, particularly in Durham Region.
- **Strategic Capacity Hedge during Nuclear Refurbishments:** Ontario's Long-Term Energy Plan has endorsed Pickering as a strategic hedge against uncertainties in the costs and schedule of refurbishment of the Bruce and Darlington units. Also, extended operation avoids the risk that unneeded gas-fired capacity would be built to address temporary capacity shortfalls during the period of intense nuclear refurbishments.
- **Emissions Reductions:** The Preferred Alternative is expected to result in a net reduction of 16 - 18 million tonnes of CO_2 relative to the operation of the electricity system with replacement energy and capacity for Pickering, which would come primarily from gas-fired generation and increased imports. Therefore, extending Pickering operations aligns with Provincial Government policies to reduce greenhouse gas emissions.
- **Increased Flexibility:** Extending some Pickering units to 2024 provides a more natural transition point for reducing OPG staff levels, as the transition would occur near the end of Darlington Refurbishment, thereby minimizing disruption for both Darlington Operations and Darlington Refurbishment.
- **Planning for Safe Store**: Would provide a longer period to plan for the safe storage of the units, allowing plans and costs to be further optimized.
- **Decommissioning and Used Fuel Funds**: A reduction of the present value of the decommissioning liability for the Pickering units (decommissioning activities can be deferred by several years) could create a larger surplus in the decommissioning fund, decreasing risks around adequacy of the funds and potentially providing future opportunities to utilize that surplus to "top-up" OPG's Used Fuel Fund.

RISK OVERVIEW

Risks associated with the Preferred Extended Operations Alternative are summarized as follows:

1. Reputational Risk (High): e.g. the risk is that interest groups that are opposed to nuclear power will contest Extended Operations, particularly during the next license renewal process, and thereby cause increased community concern. *Mitigating Actions:* Ongoing demonstration of the value and safety of Pickering through external communications, hearings and stakeholder relations.
2. Regulatory Risks (Medium): e.g. the risk that the proposed disposition for one or more known issues is not accepted by the CNSC. *Mitigating Actions:* Completion of the PSR and a pro-active approach with the CNSC to demonstrate technical fitness-for-service and maintenance of high safety standards.
3. Technical/Fitness-for-service Risks (Medium): e.g. the risk that a major component, e.g. fuel channels, does not continue to meet fitness-for-service requirements. *Mitigating Actions:* A comprehensive inspection program has been developed and included in the work program; on-going detailed life cycle management of major components.
4. System Value Assessment (Medium) – changes to Ontario system parameters such as flat or declining load growth impact, reduction in the cost of competing generation or changes to baseload supply (e.g. refurbishment schedules change) could impact the overall

economic system value negatively. *Mitigating Actions:* None that OPG can implement directly. Robust analysis across a range of scenarios and OPG ensuring that costs and generation forecasts are met or exceeded.

5. Economic Risk (Low): e.g. the risk that an unknown significant technical issue or regulatory requirement leads to prohibitively expensive repair / remediation costs. *Mitigating Actions*: On-going internal technical assessments and completion of the Periodic Safety Review.

6. Resources Risk (Low): e.g. the risk that a shortage of skilled resources in OPG results in an inability to address technical and/or operational issues and impair OPG's ability to continue to operate the plant. *Mitigating Actions:* Detailed workforce planning, training to meet demand and use of contracted resources and retention strategies and other measures, as required

7. Rate Recovery Risk (Low) – that the Ontario Energy Board (OEB) will deny the full recovery of costs through the rate setting process. *Mitigating Actions:* development of a comprehensive rate application on the merits of the business case and supporting cost/generation plan. Support from the Ministry of Energy and the IESO for the Preferred Extended Operations Alternative.

RECOMMENDATIONS:

1. Extended Operations of all six Pickering Units beyond the end of 2020 shows economic value and qualitative benefits to OPG and the Ontario electricity system. Based on this assessment, operation of two units to nominally 2022 and the remaining 4 units to nominally 2024 is recommended.
2. OPG should continue work to provide improved certainty associated with implementation of the extended operations Preferred Alternative by refining the extended operations alternative (target ends-of-life for each unit) as greater certainty becomes available regarding the technical fitness-for service of the fuel channels in each of the units.
3. The incremental costs to enable Extended Operations are estimated at approximately $310M. It is recommended that $52M (including $5M contingency) be released in order to complete the Periodic Safety Review, the Fuel Channel Life Assurance Project and to execute incremental outages and inspections in 2016 and 2017. Management will seek a full release following confirmation of the fuel channel life of the units and completion of the Periodic Safety Review.

FOR INTERNAL CONTROL

APPENDIX 1: DETAILS OF COST FORECASTS

Table A1 shows additional details, as well as the annual cost flows associated with enabling the extended operations Preferred Alternative.

The partial release of $52M is based on cost estimates for 2016 & 2017 ($47M) plus $5M of contingency.

Table A1: Preliminary Estimated Incremental Costs to Enable Extended Operations

Work Program	Total 2016 - 2020	2016	2017	2018	2019	2020	Comments
Incremental Pressure Tube, Steam Generator and Feeder Inspections & Maintenance and Outage Costs	236	4	26	34	90	82	Includes Spacer Location and Relocation work, additional Steam Generator water-lancing and feeder replacements.
Fuel Channel Life Assurance Project	9	4	5	-	-	-	Analytical and R&D work to assure high confidence in fuel channel lives
Periodic Safety Review (PSR) Update	8	7	1	-	-	-	Reduced scope PSR (Normal Cost~$20M)
Potential PSR Modifications, Balance of Plant Projects and Improved Inspection Tooling	54	-	-	17	18	19	Certainty of costs will improve after updated condition assessments and PSR is completed. Some tooling may need renewal or improvement
Total Costs to Enable Preferred Alternative	**307**	**15**	**32**	**51**	**108**	**101**	

Partial Release

Cost to enable (2016 & 2017)	**47**	**15**	**32**				Reflects 2016 & 2017 costs to enable the Preferred Alternative
Contingency	**5**		**5**				10% contingency
Total Partial Release	**52**	**15**	**37**				

10.10 The Board may, further to a request for access under **Rule 10.07** or **Rule 10.08**, make any order referred to in **Rule 10.04**.

11. Amendments to the Evidentiary Record and New Information

11.01 The Board may, on conditions the Board considers appropriate:

(a) permit an amendment to the evidentiary record; or

(b) give directions or require the preparation of evidence, where the Board determines that the evidence in an application is insufficient to allow the issues in the application to be decided.

11.02 Where a party becomes aware of new information that constitutes a material change to evidence already before the Board before the decision or order is issued, the party shall serve and file appropriate amendments to the evidentiary record, or serve and file the new information.

11.03 Where all or any part of a document that forms part of the evidentiary record is revised, the party filing the revision shall:

(a) ensure that each revised document is printed on coloured paper and clearly indicates the date of revision and the part revised; and

(b) file with the revised document(s) a table describing the original evidence, each revision to the evidence, the date each revision was made, and if the change was numerical, the difference between the original evidence and the revision(s). This table is to be updated to contain all significant revisions to the evidence as they are filed.

11.04 A party shall comply with any direction from the Board to provide such further information, particulars or documents as the Board considers necessary to enable the Board to obtain a full and satisfactory understanding of an issue in the proceeding.

12. Affidavits

12.01 An affidavit shall be confined to the statement of facts within the personal

37.03 Where all or part of a hearing is to be conducted in French, the notice of the hearing shall specify in English and French that the hearing is to be so conducted, and shall further specify that English may also be used.

37.04 Where a written submission or written evidence is provided in either English or French, the Board may order any person presenting such written submission or written evidence to provide it in the other language if the Board considers it necessary for the fair disposition of the matter.

38. Media Coverage

38.01 Radio and television recording of an oral or electronic hearing which is open to the public may be permitted on conditions the Board considers appropriate, and as directed by the Board.

38.02 The Board may refuse to permit the recording of all or any part of an oral or electronic hearing if, in the opinion of the Board, such coverage would inhibit specific witnesses or disrupt the proceeding in any way.

PART VI - COSTS

39. Cost Eligibility and Awards

39.01 Any person may apply to the Board for eligibility to receive cost awards in Board proceedings in accordance with the *Practice Directions*.

39.02 Any person in a proceeding whom the Board has determined to be eligible for cost awards under **Rule 39.01** may apply for costs in the proceeding in accordance with the *Practice Directions*.

PART VII - REVIEW

40. Request

40.01 Subject to **Rule 40.02**, any person may bring a motion requesting the Board to review all or part of a final order or decision, and to vary, suspend or cancel the order or decision.

40.02 A person who was not a party to the proceeding must first obtain the leave of the Board by way of a motion before it may bring a motion under **Rule 40.01**.

40.03 The notice of motion for a motion under **Rule 40.01** shall include the information required under **Rule 42**, and shall be filed and served within 20 calendar days of the date of the order or decision.

40.04 Subject to **Rule 40.05**, a motion brought under **Rule 40.01** may also include a request to stay the order or decision pending the determination of the motion.

40.05 For greater certainty, a request to stay shall not be made where a stay is precluded by statute.

40.06 In respect of a request to stay made in accordance with **Rule 40.04**, the Board may order that the implementation of the order or decision be delayed, on conditions as it considers appropriate.

41. Board Powers

41.01 The Board may at any time indicate its intention to review all or part of any order or decision and may confirm, vary, suspend or cancel the order or decision by serving a letter on all parties to the proceeding.

41.02 The Board may at any time, without notice or a hearing of any kind, correct a typographical error, error of calculation or similar error made in its orders or decisions.

42. Motion to Review

42.01 Every notice of a motion made under **Rule 40.01**, in addition to the requirements under **Rule 8.02**, shall:

(a) set out the grounds for the motion that raise a question as to the correctness of the order or decision, which grounds may include:

(i) error in fact;

(ii) change in circumstances;

(iii) new facts that have arisen;

(iv) facts that were not previously placed in evidence in the proceeding and could not have been discovered by reasonable diligence at the time; and

(b) if required, and subject to **Rule 40**, request a stay of the implementation of the order or decision or any part pending the determination of the motion.

43. Determinations

43.01 In respect of a motion brought under **Rule 40.01**, the Board may determine, with or without a hearing, a threshold question of whether the matter should be reviewed before conducting any review on the merits.

Ontario Energy Board　**Commission de l'Énergie de l'Ontario**

EB-2006-0322
EB-2006-0338
EB-2006-0340

MOTIONS TO REVIEW THE NATURAL GAS ELECTRICITY INTERFACE REVIEW DECISION

DECISION WITH REASONS

May 22, 2007

EB-2006-0322
EB-2006-0338
EB-2006-0340

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

AND IN THE MATTER OF a proceeding initiated by the Ontario Energy Board to determine whether it should order new rates for the provision of natural gas, transmission, distribution and storage services to gas-fired generators (and other qualified customers) and whether the Board should refrain from regulating the rates for storage of gas;

AND IN THE MATTER OF Rules 42, 44.01 and 45.01 of the Board's *Rules of Practice and Procedur*e.

BEFORE: Pamela Nowina
Vice Chair, Presiding Member

Paul Vlahos
Member

Cathy Spoel
Member

DECISION WITH REASONS

May 22, 2007

EXECUTIVE SUMMARY

In November of 2006 the Board issued a Decision with Reasons in the Natural Gas Electricity Interface Review proceeding (the "NGEIR Decision"). This proceeding was initiated by the Ontario Energy Board in response to issues first raised in the Board's Natural Gas Forum Report issued in 2004. The NGEIR Decision addressed the key issues of natural gas storage rates and services for gas-fired generators, and storage regulation.

In the NGEIR Decision, the Board determined that it would cease regulating the prices charged for certain storage services but that the rates for storage services provided to Union and Enbridge distribution customers will continue to be regulated by the Board.

The Board received three Notices of Motion for review of certain parts of the NGEIR Decision. The Board held an oral hearing to consider the threshold questions that the Board should apply in determining whether the Board should review those parts of the NGEIR Decision and whether the moving parties met the test or tests.

The Board finds that the motions do not pass the threshold tests applied by the Board, except in two areas.

First, the Board finds that the decision to cap the storage available to Union Gas Limited's in-franchise customers at regulated rates to 100 PJ is reviewable.

Second, the Board finds that the decisions regarding additional storage requirements for Union Gas Limited's in-franchise gas-fired generator customers and Enbridge's Rate 316 are reviewable.

Section C: Threshold Test

Section 45.01 of the Board's Rules provides that:

> In respect of a motion brought under Rule 42.01, the Board may determine, with or without a hearing, a threshold question of whether the matter should be reviewed before conducting any review on the merits.

Parties were asked by the panel to provide submissions on the appropriate test for the Board to apply in making a determination under Rule 45.01.

Board Staff argued that the issue raised by a moving party had to raise a question as to the correctness of the decision and had to be sufficiently serious in nature that it is capable of affecting the outcome. Board Staff argued that to qualify, the error must be clearly extricable from the record, and cannot turn on an interpretation of conflicting evidence. They also argued that it's not sufficient for the applicants to say they disagree with the Board's decision and that, in their view, the Board got it wrong and that the applicants have an argument that should be reheard.

Enbridge submitted that the threshold test is not met when a party simply seeks to reargue the case that the already been determined by the Board. Enbridge argued that something new is required before the Board will exercise its discretion and allow a review motion to proceed.

Union agreed with Board Staff counsel's analysis of the scope and grounds for review.

IGUA argued that to succeed on the threshold issue, the moving parties must identify arguable errors in the decision which, if ultimately found to be errors at the hearing on the merits will affect the result of the decision. IGUA argued that the phrase "arguable errors" meant that the onus is on the moving parties to demonstrate that there is some reasonable prospect of success on the errors that are alleged.

CCC and VECC argued that the moving parties are required to demonstrate, first, that the issues are serious and go to the correctness of the NGEIR decision, and , second, that they have an arguable case on one or more of these issues. They argued that the moving parties are not required to demonstrate, at the threshold stage, that they will be successful in persuading the Board of the correctness of their position on all the issues.

MHP argued that the threshold question relates to whether there are identifiable errors of fact or law on the face of the decision, which give rise to a substantial doubt as to the correctness of the decision, and that the issue is not whether a different panel might arrive at a different decision, but whether the hearing panel itself committed serious errors that cast doubt on the correctness of the decision. MHP submitted that a review panel should be loathe to interfere with the hearing panel's findings of fact and the conclusions drawn there from except in the clearest possible circumstances.

Kitchener argued that jurisdictional or other threshold questions should be addressed on the assumption that the record in NGEIR establishes the facts asserted.

School Energy Coalition argued that an application for reconsideration should only be denied a hearing on the merits in circumstances where the appeal is an abuse of the Board's process, is vexatious or otherwise lacking objectively reasonable grounds.

Findings

It appears to the Board that all the grounds for review raised by the various applicants allege errors of fact or law in the decision, and that there are no issues relating to new evidence or changes in circumstances. The parties' submissions addressed the matter of alleged error.

In determining the appropriate threshold test pursuant to Rule 45.01, it is useful to look at the wording of Rule 44. Rule 44.01(a) provides that:

> Every notice of motion… shall set out the grounds for the motion that raise a question as to the correctness of the order or decision…

Therefore, the grounds must "raise a question as to the correctness of the order or decision". In the panel's view, the purpose of the threshold test is to determine whether the grounds raise such a question. This panel must also decide whether there is enough substance to the issues raised such that a review based on those issues could result in the Board deciding that the decision should be varied, cancelled or suspended.

With respect to the question of the correctness of the decision, the Board agrees with the parties who argued that there must be an identifiable error in the decision and that a review is not an opportunity for a party to reargue the case.

In demonstrating that there is an error, the applicant must be able to show that the findings are contrary to the evidence that was before the panel, that the panel failed to address a material issue, that the panel made inconsistent findings, or something of a similar nature. It is not enough to argue that conflicting evidence should have been interpreted differently.

The applicant must also be able to demonstrate that the alleged error is material and relevant to the outcome of the decision, and that if the error is corrected, the reviewing panel would change the outcome of the decision.

In the Board's view, a motion to review cannot succeed in varying the outcome of the decision if the moving party cannot satisfy these tests, and in that case, there would be no useful purpose in proceeding with the motion to review.