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Ontario

BY E-MAIL

July 10, 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

OPG has reviewed the OEB staff submission filed on May 19, 2017, and advised that certain redacted information in the submission can be placed on the public record.

Attached, please find the revised, redacted version of the OEB staff submission which is consistent with OPG's review. No other changes have been made.

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

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1. INTRODUCTION

Ontario Power Generation Inc. (OPG) filed an application with the Ontario Energy Board (OEB) on May 27, 2016, seeking approval for changes in payment amounts for the output of its nuclear generating facilities and the regulated hydroelectric generating facilities for the period January 1, 2017 to December 31, 2021.

The application is underpinned by the OPG 2016-2018 business plan but was updated through impact statements filed on December 20, 2016, February 22, 2017 and March 8, 2017. In addition, further evidence was filed relating to nuclear liabilities and the capacity refurbishment variance account for the regulated hydroelectric facilities.

As of March 8, 2017, OPG is seeking approval of a hydroelectric payment amount of $41.71/MWh effective January 1, 2017 and a deferral and variance account rider of $1.44/MWh applied to the output of the hydroelectric facilities from January 1, 2017 to December 31, 2018. OPG seeks approval of its proposed IRM formula for the hydroelectric facilities for the period 2017-2021.

As of March 8, 2017, OPG is seeking approval of a nuclear revenue requirement of $16.8 billion over the period 2017-2021. The proposed revenue requirement reflects a stretch factor that OPG has applied as part of its Custom IR application. OPG also seeks approval of a deferral and variance account rider of $2.85/MWh applied to the output of the nuclear facilities from January 1, 2017 to December 31, 2018. In accordance with O. Reg. 53/05 (*Payments Under Section 78.1 of the Act*), OPG proposed smoothed nuclear payment amounts and deferred revenue requirement amounts in its application, as filed on May 27, 2016. The regulation was amended on March 2, 2017 and OPG has amended its application to reflect a smoothed weighted average payment amount (WAPA) proposal. The following table summarizes OPG's current payment amount request for the nuclear facilities:

Table 1
Requested Nuclear Revenue Requirement and Payment Amounts

	2017	2018	2019	2020	2021
Nuclear Revenue Requirement ($million)	3,161.4	3,185.7	3,273.2	3,783.5	3,397.8
Deferred Revenue Requirment ($million)	251.0	162.0	- 38.0	488.0	142.0
Production Forecast (TWh)	38.1	38.5	39.0	37.4	35.4
Smoothed Nuclear Payment Amount ($/MWh)	76.39	78.60	84.83	88.21	92.02

OPG states that approval of its current hydroelectric and nuclear payment amount and rider proposal will reflect a constant 2.5% per year WAPA increase during the 2017 to 2021 test period.

The notice for the application, as filed on May 27, 2016, was published in 82 newspapers in July 2016. The OEB has received 12 letters of comment. Twenty parties applied for and were granted intervenor status.

The draft issues list for this proceeding was set out in Procedural Order No. 1, issued on August 12, 2016. The issues were categorized as oral hearing, primary (proceeding to oral hearing if unsettled) and secondary (proceeding to written hearing if unsettled) by submissions of parties to the proceeding. The final prioritized issues list was issued on December 21, 2016. A settlement conference was held January 9 to 11, 2017. The final prioritized issues list was reprioritized on January 27, 2017, following the settlement conference.

The parties filed a partial settlement proposal on January 30, 2017 and presented the partial settlement proposal at the oral hearing on March 6, 2017. The OEB approved the partial settlement on March 20, 2017.

The oral hearing for this proceeding commenced on February 27, 2016 and ended on April 13, 2017. There were 23 hearing days in total. OPG filed its Argument in Chief (AIC) on May 3, 2017.

2. SUMMARY OF SUBMISSION

This submission reflects observations and concerns which arise from OEB staff's review of the oral and written evidence, and is intended to assist the OEB in evaluating OPG's application and in setting just and reasonable payment amounts. Not all unsettled issues on the issues list are addressed in this submission. Only those issues which, in OEB staff's opinion, require comment or analysis are addressed.

The following table and the table in Schedule A will assist with the review of the submission. The revenue requirement impacts are estimates and have been estimated in isolation of other impacts, unless noted otherwise.

Table 2
Summary of OEB Staff Submission

Section	Issue/Item	$million 2017	2018	2019	2020	2021
3.3	Equity Thickness	3.8	4.0	2.8	6.2	6.6
4.1.2	Nuclear Op. Rate Base Additions	19.7	14.1	8.7	10.7	19.8
4.3.2	DRP Rate Base Additions	2.5	2.5	2.5	22.0	26.9
6.1.1	Base OM&A	40.0	40.0	40.0	40.0	40.0
6.1.2	Outage OM&A	19.7	19.7	20.8	19.7	15.4
6.4	Nuclear Fuel (increased TWh)	-2.9	-2.9	-2.9		
6.5.6	PEO - Enabling Costs			107.0	104.0	
6.7.4	Compensation	50.0	50.0	50.0	50.0	50.0
6.8	Corporate OM&A	20.1	4.1	5.3	3.2	7.9
8.2	Nuclear Liability	69.7	66.9	65.6	57.8	44.8
11.2.4	Stretch Factor		8.3	16.3	24.4	32.4
	Total Reduction - Nuclear Revenue Requirement	**222.6**	**206.8**	**316.1**	**338.1**	**243.8**
5.2	Increase - Nuclear Production (TWh)	0.5	0.5	0.5		
11.1.6	Reduction - Hydroelectric Payment Amounts ($/MWh)	0.25	0.49	0.75	1.01	1.28

3. CAPITAL STRUCTURE AND COST OF CAPITAL

Issue 3.1 (Primary) – Are OPG's proposed capital structure and rate of return on equity appropriate?
Issue 3.2 (Secondary) - Are OPG's proposed costs for its long-term and short-term debt components of its capital structure appropriate?

3.1 Background

This is the fourth time the OEB is being called upon to establish an appropriate capital structure for OPG's regulated facilities.

In the first ever OPG payment amounts decision, EB-2007-0905, the OEB explained that "the approach to setting the capital structure should be based on a thorough assessment of the risks OPG faces, the changes in OPG's risk over time and the level of OPG's risk in comparison to other utilities."[1] In that case, the OEB determined that the 57.5% equity ratio sought by OPG was "excessive", and instead approved 47%.[2]

In the next payment amounts decision, EB-2010-0008, the OEB approved OPG's request to leave the 47% equity ratio in place, finding that there had been "no evidence of any material change in OPG's business risk".[3] The OEB also "accept[ed] that the business risks associated with the nuclear business are higher than those of the regulated hydroelectric business", but rejected the suggestion made by some intervenors that there should be separate deemed capital structures for each of the nuclear and hydroelectric businesses.

In the third and most recent payment amounts decision, EB-2013-0321, OPG proposed to keep the capital structure at 47% equity. The OEB, however, decided to lower the equity thickness to 45%, finding that the addition of 48 hydroelectric facilities to OPG's inventory of regulated assets, combined with the completion of the Niagara Tunnel Project, had lowered the business risk.[4]

In this application, OPG seeks to increase the equity thickness to 49% for the five-year term (2017-2021). OPG says this increase is needed to reflect the material increase in the business and financial risks facing the company.

OPG's application is supported by an expert report by Concentric Energy Advisors (Concentric). Concentric concluded that the change in OPG's risk profile warranted a deemed equity ratio of at least 49%.

OEB staff engaged its own independent expert, the Brattle Group (Brattle). While also concluding that the company's risk profile had changed, Brattle supported a deemed equity ratio of 48%.

Both experts took a broadly similar approach. Both asked what, if anything, has changed with respect to OPG's operating environment and business risk since it was last evaluated in the EB-2013-0321 case, and what was expected on a going-forward basis. Both assessed OPG's risk against a sample of comparable North American utilities (i.e., with nuclear and hydroelectric generation). And both considered the Fair Return Standard.

[1] Decision with Reasons, November 3, 2008 (EB-2007-0905), page 136
[2] Decision with Reasons, November 3, 2008 (EB-2007-0905), page 149
[3] Decision with Reasons, March 10 2011 (EB-2010-0008), page 116.
[4] Decision with Reasons, November 20, 2014 (EB-2013-0321), page 113

There were some methodological differences. For instance, the peer groups against which OPG was compared were different in each study, and Brattle, unlike Concentric, performed an independent analysis of OPG's credit metrics. The experts also diverged to some extent on the risk factors facing OPG over the test period. For instance Brattle gave little weight to Concentric's concerns about OPG's ability to recover its costs associated with pension and other post-employment benefits.

OPG proposes a new Hydroelectric Capital Structure Variance Account to record the hydroelectric revenue requirement impact of the difference between the capital structure approved by the OEB in this proceeding and the capital structure approved in EB-2013-0321 that underpins the hydroelectric payment amounts in the 2017-2021 test period. OEB staff does not take issue with the proposed new account, for the reasons set out in section 9.3 of OEB staff's submission.

3.2 ROE and Cost of Debt

OEB staff does not object to OPG's proposal in respect of return on equity (ROE), as summarized in OPG's AIC at pages 21-22. OPG's proposed ROE for 2017 of 8.78% is in accordance with the parameters set by the OEB for applications for rates effective in 2017. OEB staff's submission regarding the proposed Nuclear ROE Variance Account is in section 9.3. OPG does not propose to update the ROE for the regulated hydroelectric facilities during the IRM period, and this is consistent with OEB policy.

Through settlement, there was agreement on the proposed long-term and short-term debt rates.

Accordingly, OEB staff's submission below is limited to the question of the appropriate capital structure for OPG's regulated facilities.

3.3 OEB Staff Submission

OEB staff submits that a deemed equity ratio of 47% would be appropriate in this case.

OEB staff notes that in one respect this case is the opposite of EB-2013-0321. In that case, the OEB saw fit to lower OPG's equity ratio from 47% to 45% in view of the shift in OPG's generation portfolio – with the addition of 48 hydroelectric facilities to OPG's regulated fleet and the completion of the Niagara Tunnel Project. OPG's portfolio became more heavily weighted towards hydroelectric, both in terms of production (MWh) and rate base ($). The OEB noted that hydroelectric assets were less risky than nuclear ones. Now, with the DRP (and to a lesser extent, PEO), OPG's portfolio is swinging back towards nuclear. A return to the pre-EB-2013-0321 equity thickness would therefore be warranted.

OEB staff recognizes that the DRP will materially change the company's risk profile. The DRP will entail an exceptionally high level of spending – approximately $5 billion during the test period. In addition there is the execution risk associated with the DRP; that is, the risk of successfully performing a technically and logistically complex, multi-year, multi-billion-dollar construction project. As OEB staff's construction risk expert, Schiff Hardin LLP, has observed, mega-projects have a history of going over budget and behind schedule.[5]

Nonetheless, OEB staff submits, the DRP risks have been overstated by Concentric. In OEB staff's view, Concentric does not fully account for the exceptional regulatory protection OPG enjoys in respect of the DRP. First, the "need" for the project is established by O. Reg. 53/05 – there is no risk that the OEB will determine in this proceeding or a future one that the DRP was unnecessary. Second, the regulation provides that OPG will recover its DRP costs, so long as they are prudent – even if the units never re-enter into service, for example, if the program were to be cancelled mid-stream. The ability for OPG to record DRP (and PEO) overspending above OEB-approved budgets in the CRVA for eventual recoupment from ratepayers is a form of regulatory safeguard other utilities embarking on major spending programs typically do not have.

Third, Concentric's analysis does not, in OEB staff's view, adequately factor in the exceptional level of planning undertaken by OPG. A large portion of the tens of thousands of pages of evidence filed by OPG in this proceeding were meant to support OPG's assertion that its planning for the DRP was world class, and that it has internalized the "lessons learned" from past nuclear refurbishment projects that did not go well. Schiff Hardin agreed that OPG's planning was impressive, and met industry standards. As a result of that extensive planning, OPG is 90% confident that it will deliver the DRP on time and on budget. Concentric acknowledged in cross-examination that credit rating agencies and notional investors would, as part of their due diligence, take that into account.[6]

Even though the change in OPG's hydroelectric/nuclear mix, in terms of rate base, will not occur until late in the test period, when Unit 2 re-enters service in 2020, neither of

[5] Exh M1 page 7
[6] Tr Vol 17 page 182

the experts proposed a step-ladder approach where the equity ratio would go up mid-period. OEB staff agrees that a constant equity ratio throughout the term would be appropriate. OPG's spending on DRP has already begun and its need to access capital on favourable terms will continue for the entire five-year term.

Aside from the DRP risks, the main risk that Concentric identified as having increased since the last payment amounts case is the regulatory risk. Specifically, Concentric pointed to the move from cost of service regulation to incentive regulation for OPG's hydroelectric payment amounts, whereby those payment amounts would be adjusted annually by a price cap (inflation less productivity) formula, which loosens the linkage between revenues and costs.

OEB staff is not persuaded that the move to IRM causes any material increase in OPG's operating risk. As OPG states:

> With the Niagara Tunnel Project now in service, OPG's regulated hydroelectric generation facilities are in a relatively stable, steady state that is conceptually consistent with a price-cap index form of IR. The company believes that, of the three options set out in the RRFE, the 4GIRM approach is best suited to the state of its regulated hydroelectric generation facilities.[7]

This stable and steady-state environment is exactly what IRM is designed to mimic, and where the firm has roughly even opportunities to over- as well as under-perform over the five-year term. So long as the plan is well-designed and "symmetrical", and the dispersion not too great, this should not be a major consideration, and the "reward" of over-earning counter-balances the "risk" of under-earning. As Brattle observes, "there is no *ex ante* reason why incentive-based rate setting would systematically lead to over- or under-earning relative to a pure cost-based system if properly designed."[8] Moreover, "because OPG has proposed to continue all existing deferral and variance accounts approved by the OEB, the exposure is lower than under a more conventional incentive regulation mechanism (i.e., a pure price or revenue cap)."[9]

In the OEB's previous payment amounts decision, it expressly rejected the notion that moving to IRM increases the risk to the utility, and noted that in the past, it did not re-set the capital structure when electricity and gas distributors were moved to IRM:

> 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

[7] Exh A1-3-2 page 8
[8] Exh M3 page 30
[9] Exh. M3, page 30 (footnote omitted)

> 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 and 2012, 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.[10]

The other regulatory change that, according to Concentric, materially increases the risk to OPG, is the increase in the length of the term to five years for both the hydroelectric IRM and the nuclear Custom IR. However, OPG has managed to operate effectively under a three-year rate cycle, consisting of a two-year cost of service followed by one year “stay out”) since 2008. Moreover, the risk of moving to a longer term would be partially mitigated if the OEB approved OPG’s request for a mid-term review, which would enable it to update its production forecast.

In cross-examination, Concentric acknowledged that many of the other risks discussed in its report were either immaterial or unchanged as compared to the last proceeding.[11] For example, the risk of being required by the Canadian Nuclear Safety Commission to implement costly Fukushima-related safety measures is no higher than it was the last time the OEB looked at OPG’s capital structure.[12] And although Concentric’s report expressed the concern that with mandatory rate smoothing, OPG may not recover all of the deferred revenue, Concentric conceded in cross-examination that this was “[n]ot a significant factor” in its analysis.[13] Concentric also acknowledged that OPG’s revised smoothing proposal would impose less stress on OPG’s credit metrics than OPG’s initial proposal.[14]

Another risk identified by Concentric was the risk of not recovering all its pension and OPEB costs if the OEB were to permanently move from the accrual basis to the cash basis of accounting, that is, the risk of having to write off the balance of approximately $450 million in the deferral account that records the difference between cash and

[10] Decision with Reasons EB-2013-0321, November 20, 2014, page 114 (footnotes omitted)
[11] Tr Vol 17 pages 179-189
[12] Tr Vol 17 page 184
[13] Tr Vol 18 page 6
[14] Tr Vol 18 page 9. In section 11.4 of this submission, OEB staff suggests that there should be even less revenue deferred than what OPG proposes in its revised smoothing proposal. The less revenue deferred, the better for OPG’s cash flow and credit metrics

accrual.[15] Brattle, on the other hand, noted that "the distinction between accrual and cash recovery of cost is one of timing, so while OPG's current cash flow is impacted, the total cash flow is not (absent future disallowances). Therefore, the notion that the accrued difference between the accrual amount and the cash amount is 'at risk' exaggerates OPG's regulatory risk. The amount would only be lost if disallowed."[16] In OEB staff's view, there is no risk of such a disallowance with respect to the period that has already been reviewed for prudence. In the EB-2013-0321 decision, when the OEB moved OPG from accrual to cash pending the outcome of the generic proceeding on pension and OPEB costs initiated by the OEB, it explained:

> 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.[17]

In OEB staff's view, Concentric's comparative analysis is of limited assistance. Concentric acknowledged that OPG is one of a kind: in explaining what other utilities to include in its comparative analysis, Concentric said: "we describe them as comparable, but it's hard to find a company in North America that is truly comparable to OPG, because <u>there is no company quite like it</u>. It's a 100 percent regulated generator with a very unique mixture of regulated nuclear and hydroelectric assets."[18] OPG is also the only utility in Concentric's sample that is wholly owned by government. Moreover, after applying its initial screening criteria, Concentric ended up with no Canadian companies at all. It was only after relaxing those criteria that two Canadian firms were admitted, Fortis Inc. and Emera Inc.[19]

Concentric explained why including US companies in the sample makes sense, and even included an appendix to its report entitled "Precedent for Considering U.S. Data".[20] But nowhere did Concentric mention that US utilities tend to have higher approved equity ratios than their Canadian counterparts.[21] Of all the companies in Concentric's proxy group, the two Canadian utilities have the lowest equity ratios: Fortis is at 43.31%

[15] Exh. C-1-1-1 Attachment 1, pages 28-29.
[16] Exh. M3, pages 30-31. The OEB also observed that "[t]he issue of cash versus accrual is one of timing" in its EB-2013-0321 Decision with Reasons at page 91.
[17] Decision with Reasons, November 20, 2014 (EB-2013-0321), page 89
[18] Tr. Vol 18 page 25 (emphasis added).
[19] Report page 33
[20] Exh C1-1-1 Attachment 1 pages 44-46
[21] As Concentric conceded under cross-examination, the equity ratios approved by the OEB for electricity and gas distributors and for electricity transmitters are lower than what US utilities typically have or are approved for: Tr Vol 18 page 44

equity and Emera is at 40.27%.[22] Concentric observes that OPG's current approved equity ratio of 45% is also towards the lower end of the sample group, well below the mean of 49.06% and the median of 49.95%.[23] But in OEB staff's view, the mean and the median merely reflect Concentric's reliance on US data; they are not reflective of the lower equity ratios that prevail in Canada, including those that have been approved by the OEB in the distribution and transmission contexts. The same critique applies to Brattle's comparative analysis, as Brattle also relied on US data. Brattle's recommendation of 48% equity for OPG, which rests in part on that comparative analysis, is therefore too high.

In OEB staff's view, a 47% deemed equity ratio for OPG would satisfy the Fair Return Standard. It would be in line with the OEB's previous payment amounts decisions. It would return OPG to where it was before the addition of the 48 hydroelectric facilities and the completion of the Niagara Tunnel Project shifted its supply mix towards the hydroelectric side.

Although 47% is less than what OPG asks for, it is unlikely to put OPG's investment grade credit rating at risk. One of the two credit rating agencies that follows OPG, DBRS, considers an equity ratio of anywhere between 45.00% and 49.99% to be "good".[24] A review of OPG's DBRS rating history shows that it has remained unchanged at A (low) since 2002, despite three OEB payment amounts decisions in that time, two of which approved an equity ratio lower than what OPG had requested.[25] The other rating agency that follows OPG, Standard & Poor's, did not downgrade OPG after any of those decisions. Indeed, the only time Standard & Poor's downgraded OPG was in response to a downgrade of the Province's credit rating rather than to any company-specific change in risk.[26]

OEB staff estimates that the revenue requirement impact of adding 100 basis points (i.e., one full percentage point) to the equity thickness is $11.7 million over the five-year term on the nuclear side alone, as shown in the table below. In addition, $28.6 million would be recorded in the Hydroelectric Capital Structure Variance Account.

[22] Exh C-1-1 Attachment 1 page 39 (Figure 9); see also page 40 (Figure 10)
[23] Exh C1-1-1 Attachment 1 pages 40-42
[24] DBRS, "Methodology: Rating Companies in the Regulated Electric, Natural Gas and water Utilities Industry,", October 2015, Exh L-3.1-Staff-17, Attachment 1, page 10
[25] DBRS Rating Report on OPG, March 25, 2014, Exhibit A2-3-1, Attachment 3, page 10; Tr Vol 18 pages 52-53.
[26] Tr Vol 18 pages 48 and 185; L-3.1-20-VECC-8

Table 3
1% Change in Equity Thickness

$million	2017	2018	2019	2020	2021	Total
Nuclear	1.9	2	1.4	3.1	3.3	11.7
Hydroelectric	5.7	5.7	5.7	5.7	5.7	28.6
						40.3
Nuclear data - inputs to RRWF, March 8, 2017 version						
Hydroelectric data - Exh L-9.8-Staff-217						

It follows that, over the entire term, the difference between OEB staff's proposed 47% and OPG's proposed 49% is $23.4 million less in nuclear revenue requirement. There would also be $57.2 million less recorded in the account than would have been recorded under OPG's proposal, for a total incremental revenue requirement difference of $80.6 million over the five year term. OEB staff's calculations are based on OPG's application and do not factor in any disallowances that may be made by the OEB. Although OEB staff has recommended certain disallowances in this submission, OEB staff considers that they are not large enough to affect the capital structure analysis.

4. NUCLEAR CAPITAL EXPENDITURE AND RATE BASE

4.1 Nuclear Operations Capital Expenditure and Rate Base

Issue 2.1 (Primary) – Are the amounts proposed for nuclear rate base (excluding those for the Darlington Refurbishment Program) appropriate?
Issue 4.2 (Primary) – Are the proposed nuclear capital expenditures and/or financial commitments (excluding those for the Darlington Refurbishment Program) reasonable?
Issue 4.4 (Primary) – Are the proposed test period in-service additions for nuclear projects (excluding those for the Darlington Refurbishment Program) appropriate?

4.1.1 Summary of Request

OEB staff will provide its submissions on Issues 2.1, 4.2 and 4.4 in the section below as they are related issues.

OPG's planned nuclear operations capital expenditures for the test period are set out in the following table:[27]

[27] Exh D2-1-2 Chart 1

Table 4
Capital Expenditures ($ million)

Category	2017	2018	2019	2020	2021
Project Portfolio	253.0	238.0	248.0	259.0	180.0
Darlington New Fuel[28]	0	0	15.3	0	0
Mixed Fixed Assets	26.0	20.0	19.1	19.5	19.3
Total	**279.0**	**258.0**	**282.4**	**278.5**	**199.3**

The Support Services capital expenditures are undertaken by the Information Technology and Real Estate groups. The assets can provide benefits to both the regulated hydroelectric and nuclear businesses. Where support service assets can be directly assigned to either hydroelectric or nuclear, they are declared as in-service additions to rate base for the respective business units. If the assets cannot be directly assigned they are held centrally and the regulated businesses are charged a service fee for use of the assets.[29] The Support Services capital expenditures over the test period range from $22 million to $28.5 million.[30]

On the basis of the above noted capital expenditures, and prior period capital expenditures, OPG requested approval of the proposed in-service amounts related to nuclear operations (and Support Services nuclear capital[31]) as set out in the following table:[32]

[28] Exh F2-5-1 page 3. OPG stated that half of the cost of the new fuel load will be capitalized in 2019 when the new fuel is loaded into the reactor. After Unit 2 is declared in service in 2020, the fuel will be depreciated over the station's remaining life. OPG stated that this is consistent with the concept that half of the fuel in the fuel channels will be unused at the end of the station life. The other half of the cost of the new fuel load for Unit 2 will be expensed in 2020 when Unit 2 is declared in-service.
[29] Exh D3-1-1 pages 1-2
[30] Exh D3-1-1 Table 1. The amounts cited reflect the total capital expenditures and therefore are for both the hydroelectric and nuclear businesses.
[31] The Support Services in-service amounts cited in the table reflect only the nuclear portion that is directly assigned to nuclear rate base.
[32] Exh B1-1-1 Chart 1

Table 5
Bridge Year and Test Period In-Service Capital Additions ($ million)

Category	2016	2017	2018	2019	2020	2021
Nuclear Operations	497.0	389.0	315.2	239.3	300.4	215.6
Support Services	10.5	8.1	18.0	5.0	5.0	5.0
Total *	**507.5**	**397.1**	**333.2**	**244.3**	**305.4**	**220.6**

* Excluding ARC and DRP

OPG also requested approval of rate base amounts as follows:[33]

Table 6
Rate Base ($ million)

Category	2017	2018	2019	2020	2021
Net Plant (Excluding DRP)	1,780.5	1,861.0	1,848.6	1,813.9	1,848.4
Net Plant (DRP)	611.9	601.5	586.7	4,699.1	5,154.5
Asset Retirement Costs	524.0	446.7	369.5	292.2	249.6
Total Nuclear Net Plant	2,916.4	2,909.2	2,804.8	6,805.2	7,252.5
Cash Working Capital	11,0	11,0	11,0	11,0	11,0
Fuel Inventory	251.9	242.2	224.2	210.7	208.6
Materials and Supplies	448.7	444.5	436.3	427.0	415.0
Total Rate Base	**3,627.9**	**3,606.9**	**3,476.2**	**7,453.8**	**7,887.0**

OPG calculated the net fixed / intangible asset portion of rate base using a mid-year average methodology. For large in-service additions or adjustments, where the in-

[33] AIC page 15. The amounts set out here reflect the removal of the D2O project from the in-service amounts (and rate base) as shown at Exh N2-1-1 Chart 3 and changes to the ARC as shown at Exh N1-1-1 Attachment 1, Table 3.

service addition amount, or the amount of the adjustment, exceeds $50 million, the specific time in which the addition, or adjustment, is expected is used (instead of the mid-term average) to improve accuracy. This is the same methodology used by OPG in previous cases.[34]

OPG noted that the working capital included in rate base consists of cash working capital, fuel inventory and materials / supplies. The fuel inventory and materials and supplies values for rate base are determined using a mid-year average of opening and closing balances during the test period. Cash working capital is determined using a lead/lag study. OPG stated that the approaches used for the calculation of working capital are consistent with the methodologies previously approved by the OEB.[35]

4.1.2 Summary of OEB Staff Submission

OEB staff will focus its submissions on the nuclear operations related capital and, to a lesser extent, the nuclear portion of the support services capital in this section. OEB staff's submission on the DRP-related capital is set out at section 4.3 and the ARC-related amount is at section 8.1.

OEB staff notes that the nuclear operations and support services capital expenditures forecast for the test period[36] make up a portion of the in-service amounts requested for the test period[37] and will also be included as part of in-service amounts that will be requested for a future period. OEB staff has limited its submissions to the in-service amounts (and related nuclear rate base amounts) requested for approval as part of this proceeding as it is these amounts that will immediately impact ratepayers.

OEB staff submits that it has no concerns with the methodologies used to calculate rate base (including the net fixed / intangible asset portion and working capital).[38] However, OEB staff's submissions summarized below with respect to certain reductions to proposed in-service amounts will impact the rate base amount.

With respect the nuclear operations and support services in-service capital amounts, OEB staff submits that:

[34] AIC page 15
[35] AIC page 16
[36] Exh D2-1-2 Chart 1, and Exh D3-1-1 pages 1-2
[37] The remainder of the in-service amounts is associated with historical nuclear capital expenditures.
[38] The methodologies are discussed in the AIC at pages 15-16.

- The basis for the OEB's approval should be the updated in-service amounts provided at Undertaking J21.1, which reflects actual 2016 capital additions and a revised forecast of the 2017-2021 capital additions. Furthermore, the updated forecast should be reduced by approximately $27.3 million in each year 2017 to 2021 to reflect a likely overstatement of achievable capital additions (which represents an aggregate reduction over the test period of $136.3 million).

- A permanent reduction to the capital costs associated with the Auxiliary Heating System (AHS) project of an estimated $28 million and the Operations Support Building (OSB) project of an estimated $7 million is appropriate due to OPG's imprudent management of these projects.

4.1.3 Nuclear Operations Capital and Support Services Capital – Updated Forecast for In-Service Amounts

Background

OPG filed its proposed nuclear operations and nuclear support services in-service capital amounts in Exh B1-1-1. As part of its undertaking responses, OPG provided the actual 2016 in-service amounts associated with its nuclear operations and support services capital projects. OPG also provided updated in-service amounts for the 2017-2021 period, which reflect OPG's current view of the capital that will go into service during the test period. OPG noted that the update is based on its 2017-2019 Business Plan, adjusted to account for 2016 actuals and subsequent changes in timing of in-service amounts over the 2016-2021 period.[39]

OPG stated that exact forecasting of in-service amounts is challenging due to the numerous factors that affect both the amount of capital declared in-service and its timing.[40] With respect to project timing, OPG stated that if a project that is forecast for completion in a particular year is delayed into the following year, there will be a significant impact on in-service amounts for both years. OPG also stated that the shift of in-service amounts from one year to the next is not unusual and is illustrated by the variances between historical forecast and actual amounts from 2013 to 2016. OPG noted that two years yielded positive variances and two years yielded negative variances (in a cyclical pattern).[41]

[39] Undertaking J21.1
[40] AIC page 30
[41] AIC page 31

OPG noted that the updated nuclear operations and Support Services in-service amounts based on its current view are approximately $2.009 billion over the 2016-2021 period. This compares to $2.008 billion reflected in the pre-filed evidence. OPG stated that, on average, the resulting rate base values over the test period would be approximately $30 million lower than originally requested, which reflects shifts in timing of the in-service amounts. OPG noted that while the rate base will be lower on average, the annual depreciation expense would be $8 million higher, on average, than the original request.[42] OEB staff invites OPG to explain, in its reply submission, why, if rate base is lower on average, there is an increase in depreciation expense on average. Are there specific assets going into service, in the updated view, that have a significantly higher associated depreciation expense? Overall, OPG argued that its current view of the 2016-2021 net plant rate base associated with nuclear operations and support services capital in-service amounts is substantially unchanged relative to the pre-filed evidence, despite the variance between forecast and actual in-service amounts in 2016. OPG stated that a reasonable approach would be to assess in-service forecasts and variances over the test period rather than on an annual basis.[43]

OPG maintained that its original proposed nuclear operations and support services capital in-service request is reasonable. Therefore, it proposed that no change be made to its requested capital in-service amounts set out in the pre-filed evidence for the test period.[44]

In the table below, OEB staff provides a comparison of the in-service amounts between the pre-filed evidence and the update provided at Undertaking J21.1.[45]

[42] Undertaking J21.1.
[43] AIC page 31
[44] Undertaking J21.1
[45] Derived from Exh B1-1-1 Chart 1 and Undertaking J21.1 Attachment 2 Table 1

Table 7
Bridge Year and Test Period - Nuclear Capital In-Service Amount Variances ($ million)

		Category ($ million)		
		Nuclear Operations Capital Projects	**Support Services Capital Projects**	**Total Nuclear In-Service Additions***
2016	Pre-Filed	497.0	10.5	**507.5**
	Actual (Updated)	292.0	8.9	**300.9**
	Variance	-205.0	-1.6	**-206.6**
2017	Pre-Filed	389.0	8.1	**397.1**
	Updated	479.0	29.8	**508.8**
	Variance	90	21.7	**111.7**
2018	Pre-Filed	315.2	18.0	**333.2**
	Updated	354.7	17.4	**372.1**
	Variance	39.5	-0.6	**38.9**
2019	Pre-Filed	239.3	5.0	**244.3**
	Updated	385.4	7.7	**393.1**
	Variance	146.1	2.7	**148.8**
2020	Pre-Filed	300.4	5.0	**305.4**
	Updated	244.7	4.7	**249.4**
	Variance	-55.7	-0.3	**-56.0**
2021	Pre-Filed	215.6	5.0	**220.6**
	Updated	181.6	3.2	**184.8**
	Variance	-34.0	-1.8	**-35.8**

* Excluding ARC and DRP

OEB Staff Submission

OEB staff submits that the basis for the in-service amounts for the nuclear operations and support services capital should be the updated forecast provided by OPG at Undertaking J21.1. OEB staff further submits that the updated forecast of the in-service amounts should be reduced by $136.3 million over the 2017-2021 period (a reduction to the updated in-service amounts of approximately $27.3 million each year). The reasons for OEB staff's submissions are set out below.

OEB staff notes that, as set out in Table 7, there are significant annual changes to the actual and forecast in-service amounts during the 2016-2021 period between the pre-filed evidence and the updated evidence. In contrast to the DRP-related capital additions discussed at section 4.3.5, for the nuclear operations and support services capital additions there is no true-up mechanism available to capture the revenue requirement impact of variances between actual and forecast in-service amounts during the test period.[46] Therefore, OEB staff submits that the best available forecast of the in-service amounts for the nuclear operations and support services capital must be used as the starting point for the OEB's approval. OEB staff notes that the OEB typically requires that the best available information be used when forecasting and in the absence of a true-up mechanism the usual approach must be applied in this case.

Based on 2016 actuals, as set out in Table 7, there is a $206.6 million reduction to 2016 nuclear operations and support services in-service amounts between the updated evidence and the pre-filed evidence. However, over the entire 2016-2021 period, OPG forecasts that there will be an approximate $1 million increase to the in-service amounts when comparing the updated information to the pre-filed evidence. Overall, the timing of the in-service amounts has changed but the quantum of in-service amounts in aggregate for the 2016-2021 period is relatively stable based on OPG's updated forecast. OPG further elaborated that the average rate base over the period would be $30 million lower than the original request but the annual depreciation expense would be $8 million higher, on average, when compared to the original request.[47] OEB staff suggests that OPG, in its reply submission, provide the revenue requirement for each year (2017 to 2021) associated with each of the pre-filed and updated forecasts of in-service amounts. This will likely assist the OEB in its deliberations.

As the updated forecast of in-service amounts over the 2016-2021 period is virtually unchanged from the pre-filed forecast on an aggregate basis, OPG argued that the OEB should assess the reasonableness of in-service forecasts over the entire test period (as opposed to on an annual basis).[48] OEB staff agrees that assessing in-service additions over longer periods of time is a useful exercise. This type of analysis allows for year-to-year variances related to in-service amounts to be ignored (as the causes of these variances can simply be related to timing issues associated with station outages)[49] and a more holistic understanding of overall capital additions to be gained. OEB staff has used this type of analysis in its submission below regarding OPG's historic nuclear operations capital in-service amounts. However, from a regulatory perspective, the amount of capital that is forecast to be placed in service in a given year has actual

[46] Undertaking J21.4. OPG confirmed that the nuclear operations capital is not eligible for CRVA treatment.
[47] Undertaking J21.1
[48] AIC page 31
[49] AIC page 30

impacts on rate base (and therefore revenue requirement). Therefore, the OEB must be satisfied that the annual in-service amounts are reasonable.

In requesting that its original forecast of in-service amounts be used, when there is a more recent forecast available (which reflects actual 2016 in-service amounts), OPG is essentially asking the OEB to approve revenue requirement in each year of the test period that is associated with a forecast that it knows to be incorrect. This is most directly illustrated by the fact that using its original forecast would have the OEB approve $206.6 million of in-service capital in 2016 (which would be reflected in 2017 rate base) that was not actually placed in service. OEB staff submits that this is not a reasonable request.

On a principled basis, OEB staff submits that the OEB should evaluate the appropriateness of annual in-service amounts as there are annual revenue requirement impacts directly associated with in-service timing. Therefore, for the purpose of establishing the appropriate level of in-service capital additions, the OEB should use the most accurate forecast of in-service amounts for each year of the test period.

While OEB staff believes that the updated forecast provided at Undertaking J21.1 is the appropriate starting point for the OEB's approval (as it reflects OPG's current view of the nuclear capital that will be placed in-service during the test period), OEB staff submits that the updated in-service amount forecast for the test period is overstated and should be reduced. The updated forecast shows that while OPG will be behind on the capital additions going in to the test period ($206.6 million reduction for 2016), it will quickly make up for the lower than planned in-service additions in 2017, 2018 and 2019.[50] OPG advised that of the $206.6 million of capital additions that were not placed in service in 2016, $70.3 million has been placed in service in 2017.[51]

OEB staff submits that OPG's current outlook is overly optimistic. OPG has a vast number of projects (across the DRP and the nuclear operations portfolio) that it plans to complete and place in service during the test period and all of these projects are competing for finite resources. In OEB staff's view, it would be exceedingly difficult for OPG to actually achieve the updated level of forecasted in-service amounts during the test period. It is OEB staff's view that going in to the test period $206.6 million below the original planned capital additions,[52] even recognizing that $70.3 million of that amount is

[50] Undertaking J21.1
[51] Undertaking J14.1
[52] Undertaking J21.1

already placed in service in 2017,[53] will result in a cascading impact whereby completion of capital projects (and the associated in-service amounts) will be delayed and a portion of the overall in-service amounts requested will fall outside the test period.

In addition, to support its argument that the updated forecast of in-service amounts is likely overstated, OEB staff has provided a variance analysis of OPG's historical nuclear operations in-service amounts (2010-2016) in the table below.[54]

Table 8
Historic – Nuclear Operations Capital In-Service Amount Variances ($ million)

	2010	2011	2012	2013[55]	2014	2015	2016	Total
Forecast	191.5	175.5	187.6	180.7	158.3	141.7	497.0	1,532.3
Actual	249.0	103.2	131.9	212.6	148.6	204.1	292.0	1,341.4
Variance	57.5	-72.3	-55.7	31.9	-9.7	62.4	-205	-190.9

* Excluding Support Services, ARC and DRP

The variance analysis highlights, similar to what OPG set out in its AIC,[56] that there are substantial year-to-year variances of in-service amounts (as between approved / planned and actual). It also shows that over a reasonable sample (2010-2016), OPG, in aggregate, has placed less capital in service than it had forecast. Over the 2010-2016 period, OPG placed $190.9 million less nuclear operations capital in service than approved / planned (which represents a 12% variance).[57]

For the above reasons, OEB staff submits that the OEB should approve the updated forecast in-service amounts for the nuclear operations and support services capital for the 2016-2021 period with an aggregate reduction of $136.3 million (a 7% reduction). The proposed reduction represents the difference between the $206.6 million capital addition shortfall in 2016 net of the $70.3 in-service amount that was moved (and is

[53] Undertaking J14.1
[54] EB-2013-0321, Decision with Reasons, November 20, 2014, page 52 (2010-2012); Exh D2-1-3 Table 4 (2013-2015); and Undertaking J21.1 (2016)
[55] For 2013, the actual nuclear operations in-service amounts set out in the EB-2013-0321 Decision with Reasons is $311.5 million. Using that amount for the 2013 actuals as opposed to the $212.6 million set out in Exh D2-1-3 Table 4, results in a total variance over the 2010-2016 period of -$92.1 million (as opposed to -$190.9 million based on the evidence in the current proceeding).
[56] AIC page 31
[57] OEB staff notes that the variance could be as little as $92.1 million (based on the information set out in the EB-2013-0321 Decision with Reasons). This reflects a variance of about 6%.

already in service) to 2017.[58] The $136.3 million reduction should be divided equally in each year 2017-2021 ($27.3 million each year) to reflect the cascading impact of the 2016 shortfall discussed above whereby a portion of the planned in-service amounts will likely be delayed into a future year.

The following table highlights the nuclear capital in-service amounts based on OEB staff's proposal.

Table 9
OEB Staff Proposal - Nuclear Capital In-Service Amounts ($ million)

	2016	2017	2018	2019	2020	2021	Total
OPG Updated Total Nuclear In-Service Additions*[59]	300.9	508.8	372.1	393.1	249.4	184.8	2,009.1
OEB Staff Proposed Reduction	0	27.3	27.3	27.3	27.3	27.3	136.3
OEB Staff Proposed Total Nuclear In-Service Additions*	300.9	481.5	344.8	365.8	222.1	157.5	1,872.8

* Excluding ARC and DRP

OEB staff submits that the approved rate base amounts for the 2017-2021 period should reflect OEB staff's position set out above.[60]

OEB staff notes that, at the time of the next rebasing, OPG will request approval of a nuclear rate base amount that reflects the nuclear operations and support services assets that were actually placed in-service during the test period. If the actual in-service amounts are greater than OEB-approved, and the costs are prudently incurred, OPG would be allowed to include those incremental in-service amounts in rate base in 2022. Alternatively, if the actual in-service amounts are lower than OEB-approved, the applied-for rate base in 2022 will reflect the lower than planned capital additions. In addition, as proposed by OEB staff in section 4.3.9, the revenue requirement impact of

[58] Undertaking J14.1
[59] Undertaking J21.1 Attachment 2 Table 1
[60] OEB staff asks that OPG, in its reply submission, provide the revenue requirement for each year (2017 to 2021) associated with OEB staff's proposed in-service amounts. This will likely assist the OEB in its deliberations.

the actual lower than OEB-approved in-service amounts for the nuclear operations and support services capital during the test period should be used to offset debit balances in the CRVA.

OEB staff also notes that it is unclear exactly what project cost or timing changes are reflected in the updated forecast of nuclear capital operations in-service amounts for the 2017-2021 period (provided at Undertaking J21.1).[61] OEB staff believes that it is very likely that the updated forecast includes revised project cost estimates from the most recent business case summaries for the major capital projects.[62]

As discussed in section 4.1.4, OEB staff submits that for some of the nuclear operations capital projects that will be placed in service during the test period (and the projects are not complete nor very near to completion) there are already concerns with respect to the prudence of the costs incurred. Therefore, if the OEB accepts OEB staff's proposal, the OEB should be clear in its findings that it is only providing approval of an envelope of in-service amounts for the nuclear operations and support services capital for the test period (in order to provide the necessary revenue requirement to support a reasonable level of capital that will be placed in service). The OEB should state that it is not granting explicit approval of incremental forecast costs (relative to the first execution business case estimates) for any specific project that will come into service during the test period. In its decision, the OEB should note that the actual costs (and therefore any variances above the original estimates) for the nuclear capital projects will need to be reviewed at the time of the rebasing that takes place after the projects are complete on a final basis. Furthermore, the OEB should make it clear that its decision in this proceeding in no way restricts the ability of a future panel of the OEB to disallow from the inclusion in rate base imprudently incurred nuclear capital costs that are placed in service during the test period.

Overall, OEB staff's submission, if accepted by the OEB, would disallow OPG from recovering the revenue requirement associated with $136.3 million of capital additions (relative to the updated forecast) by the end of the test period. OEB staff believes that this disallowance is warranted as the reduced in-service amounts suggested by OEB staff likely represent a more reasonable forecast of the actual capital additions that will occur during the test period.

[61] In Undertaking J21.1, the in-service amounts were updated based on the latest available information. However, updates to the underlying projects that makeup the revised in-service amounts were not provided.
[62] OEB staff invites OPG, in its reply submission, to clarify whether OEB staff's understanding is correct.

4.1.4 Nuclear Operations Capital – Prudence of Incremental Costs

Background

OPG provided a list of the nuclear operations capital projects that have: (a) expenditures during the test period; (b) in-service amounts in 2016 or the test period; and (c) completed / deferred projects (from EB-2013-0321 or subsequent proceedings).[63]

For many of the nuclear operations projects, there have been significant variances, both positive and negative, between the latest forecast cost (or the actual cost) and the original estimated cost.[64]

OPG is seeking approval, in this proceeding, of in-service amounts and the related rate base amounts during the 2016-2021 period that reflect the actual or forecast cost of these nuclear operations projects.

OEB Staff Submission

OEB staff submits that the OEB should permanently disallow the recovery from ratepayers of imprudently incurred costs associated with the Darlington Auxiliary Heating System (AHS) project and the Darlington Operations Support Building Refurbishment (OSB) project. These two projects are either very near to completion (AHS) or complete (OSB) and, in OEB staff's view, it is clear from the evidence that a portion of the total costs for these projects were imprudently incurred.

OEB staff also submits that there are a number of other projects that will fully, or partially, come into service during the test period that may include costs that were imprudently incurred. Therefore, the OEB should identify these projects for potential future disallowance of cost recovery with a final determination to be made when these projects are complete (and the final capital cost is known).

In the EB-2013-0321 Decision with Reasons, the OEB approved in-service capital additions of $36.3 million and $29.7 million for the AHS project and OSB project respectively.[65] At the time of that decision, both of the projects were classified as DRP-related projects. Therefore, variances between the actual cost and the approved in-

[63] Exh D2-1-3 Tables 1-3
[64] Exh L-4.2-AMPCO-17, and Undertaking JT2.16
[65] EB-2013-0321, Decision with Reasons, November 20, 2014, page 56 and 58

service amounts would have been recorded in the CRVA and been subject to a prudence review.

OPG noted that as part of the development of the RQE, OPG evaluated the scope of the DRP to ensure that any work included in the scope was to extend the life of the Darlington units. Where work could be done as part of the normal station life cycle management program, it was reclassified to the nuclear operations portfolio. OPG determined that the AHS is properly considered a nuclear operations project because it provides reliable back-up steam to the entire station. Similarly, OPG determined that the OSB is properly considered a nuclear operations project because it provides services that support the daily operations of the entire station.[66]

As the AHS and OSB projects have both been reclassified as nuclear operations projects,[67] they are no longer subject to CRVA treatment.[68] As part of the current proceeding, OPG is requesting approval to add incremental capital (beyond what was approved in EB-2013-0321) related to these two projects to rate base. This proceeding is the appropriate opportunity to undertake a prudence review of the AHS and OSB projects (as these projects are either complete or near completion).

The AHS is very near to completion[69] with an updated in-service date of October 2017 (originally forecast for April 2016).[70] The first execution business case for the project estimated a total cost for the project of $45.6 million and the revised final cost of the project is estimated to be $107.1 million.[71] The forecast in-service amount is $98.7 million (largely placed in service in 2017) based on the updated evidence.[72] A portion of the total cost of the project is related to removal and decommissioning costs and therefore would not be reflected in the requested in-service amount.[73]

In 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 (the 2014

[66] Exh L-4.3-Staff-71 page 2
[67] Exh L-4.3-Staff-71 page 2
[68] Undertaking J21.4
[69] Tr Vol 12 page 150. OPG stated that while the project is not complete, the building, the boiler system and all of the piping is complete. The facility has been tested but it will not be placed into service until a final environmental qualification issue is resolved.
[70] Undertaking JT2.16, and Exh D2-1-3 Table 1
[71] Undertaking JT2.16.
[72] Undertaking JT2.16. OEB staff notes that Exh D2-1-3 Table 1 states that the in-service amount for the AHS project is $94.3 million ($94.2 million in 2016 and $0.1 million in 2017). OEB staff is unsure which is the correct in-service amount associated with this project. OEB staff expects that the in-service date has moved to 2017 for this project.
[73] Tr Vol 12 page 151

Report), a review of a number of campus plan projects (including the AHS) undertaken by OPG's Project and Modifications (P&M) group was provided.[74] The P&M group is a functional group of OPG that was responsible for a number of the F&I (or campus plan projects).[75]

In summary, the 2014 Report stated that:

> Many of the Campus Plan Projects are forecasted to complete significantly beyond the approved budgets and schedules. In fact, schedule adherence is so poor that the Campus Plan work poses multiple threats to the start of Refurbishment. Over the last quarter, BMcD/Modus has engaged in a thorough review of several key Campus Plan projects in an attempt to identify trends and understand the causes of these cost and schedule overruns. Our findings show that the predominant cause was OPG's Projects & Modifications ("P&M") organization, who is managing this work for the DR Project, incorrectly applied an "oversight" project management approach for its EPC contracting strategy, leading to a series of cascading management failures and contractor performance issues, including misunderstandings of scope, uncontrolled scope creep, poor quality cost estimates, unrealistic and incorrect schedules and an inability to manage known risks, additional costs and delays. For multiple reasons described herein, P&M was completely overwhelmed in trying to manage Campus Plan Projects – in particular, the two largest of these projects, the D2O Storage Facility and Auxiliary Heat Steam Plant ("AHS") which were the "pilot" projects for this new contracting model [Emphasis added].[76]

More specifically, with respect to contractor management and contractor performance of the campus plan projects, the 2014 Report stated that OPG placed excessive faith in the contractor's ability to complete the necessary work and an over-reliance on the perceived ability of the EPC contracting model to shift project risk to the contractor and reduce the need for active project management.[77] The 2014 Report further stated that the P&M group did not have the necessary experience, training or internal management direction to properly manage the campus plan work.[78]

The 2014 Report noted that the management failures were most evident with respect to the D2O Storage and AHS projects. It was noted that in relation to both projects, the P&M group sought full funding approval prior to completing the appropriate level of design work.[79]

For the D2O and AHS projects, the 2014 Report stated that the P&M group mischaracterized vendor bids in the business case summaries. Specifically, for AHS,

[74] Exh L4.3-Staff-72-Attachment 4
[75] Exh L4.3-Staff-72-Attachment 4 page 1
[76] Exh L4.3-Staff-72 Attachment 4 page 1
[77] Exh L4.3-Staff-72 Attachment 4 page 6
[78] Exh L4.3-Staff-72 Attachment 4 page 6
[79] Exh L4.3-Staff-72 Attachment 4 page 7

the business case summary stated that the estimate was a high-confidence Class 3 estimate.[80] OPG, in cross-examination, stated that the original estimate was actually a Class 5 estimate.[81] The 2014 Report also stated that the P&M group overvalued price as a consideration in selecting a contractor, especially in the context that the work was to be completed on a cost-reimbursable basis (and the bid prices were not binding). The P&M group chose the low-cost bidder even when other contractors' qualifications and project approach were viewed more favourably.[82] OPG stated that the selected contractor was challenged in executing the project.[83]

The 2014 Report also stated that the P&M group did not actively manage ongoing risks as part of an effective risk management program. Once a project obtained full funding for execution very little attention was paid to day-to-day risk management – including the ongoing identification of new risks and opportunities.[84]

Finally, the 2014 Report found that the gating process[85] used for the AHS project suffered from problems in execution. The changes in the design and scope of the project were not accurately or timely reported to OPG's management by the P&M group. The consequences of the poor implementation of the gating process was that senior management was deprived of the ability to: (a) stop the design changes that led to the cost increases; (b) stop the project entirely and resort to one of the other evaluated options; and (c) mitigate the impact of schedule delays and overruns.[86]

The 2014 Report went as far as to state that "...the consequences to OPG are two projects [D2O and AHS] that may cause external stakeholders to question OPG's management prudence."[87]

OEB staff questioned OPG about the AHS project at the oral hearing. OPG admitted that the results reflected poor performance of its management of the project.[88] However, OPG stated that the incremental costs of the project were primarily caused by: (a) an overstatement of the confidence level of the estimate for the project which was completed before any significant amount of design work was completed (Class 3 as

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[80] Exh L4.3-Staff-72 Attachment 4 page 7
[81] Tr Vol 12 page 161
[82] Exh L4.3-Staff-72 Attachment 4 page 7
[83] Tr Vol. 12 page 154
[84] Exh L4.3-Staff-72 Attachment 4 page 7
[85] AIC page 25. OPG noted that the gating process was first applied to the AHS and OSB projects.
[86] Exh L4.3-Staff-72-Attachment 4 pages 10-11
[87] Exh L4.3-Staff-72-Attachment 4 page 11
[88] Tr Vol 12 page 165

opposed to Class 5);[89] and (b) scope changes that arose during the more substantial design phase of the project (custom requirements for the equipment to fit the building).[90]

In its AIC, OPG further stated that the observed cost variances largely relate to inadequate scope in the initial estimates, which were not indicative of the projects' true costs (i.e., had the projects been properly estimated at the correct estimate class initially, the original cost estimate would have been close to the current cost of each project).[91] OPG stated that this conclusion was reached on the AHS project in the "Supplemental Report to Nuclear Oversight Committee – 2nd Quarter 2014" (the Supplemental Report).[92]

OEB staff submits that a portion of the AHS cost overruns are directly associated with a poor original cost estimate and certain scope changes that became necessary after more substantive design work had been completed. It is OEB staff's position that costs exceeding an artificially low original estimate should not necessarily be, in the absence of other issues, considered imprudent. In other words, simply because the final cost of a project is higher than a poorly developed estimate does not mean all incremental spending is automatically imprudent. However, with respect to the AHS project, there is strong evidence of management imprudence.

As discussed above, the 2014 Report outlines a number of concerns with respect to OPG's management of the AHS project. Specifically, the P&M group's contractor selection process was flawed and placed insufficient emphasis on the contractor's qualifications and ability to actually complete the work. Also, once a project received funding for execution, very little, if any, attention was paid to day-to-day risk management.[93] In addition, the lack of proper reporting to senior management limited OPG's ability to mitigate schedule and cost overruns.[94] OEB staff submits that these issues were responsible for a portion of the cost overruns experienced associated with the AHS projects. These are true "management failures", in the words of the 2014 Report,[95] and had these issues been avoided the total final cost of the project likely would have been reduced as the projects would have been executed more efficiently. Due to these management failures, OEB staff submits that a portion of the cost

[89] Tr Vol 12 page 152 and 161
[90] Tr Vol 12 page 154
[91] AIC page 28.
[92] Undertaking J15.3 Attachment 1 page 3
[93] Exh L4.3-Staff-72-Attachment 4 page 7
[94] Exh L4.3-Staff-72-Attachment 4 pages 7-11
[95] Exh L4.3-Staff-72-Attachment 4 page 1

overruns of the AHS should be deemed imprudent and permanently disallowed from inclusion in rate base.

In response to a question from SEC at the oral hearing, OPG stated that it measures its own project performance against the first execution release.[96] OEB staff submits that, from a regulatory perspective, the OEB should also consider cost variances as the difference between the first execution release / initial execution business case summary (as opposed to a superseding business case release) and the final cost of the project.

OEB staff submits that 50% of the incremental capital cost (as between the first execution release and the final amount) should be disallowed from inclusion in rate base on a permanent basis. OEB staff disagrees with OPG's assertion that "had the projects been properly estimated at the correct estimate class initially, the original cost estimate would have been close to the current cost of each project."[97] OPG is relying on the Supplemental Report for this argument. OEB staff submits that the Supplemental Report states that there were poorly developed initial cost estimates for the AHS project and many of the cost variances are scope based (which OEB staff does not dispute). However, the Supplemental Report also states that the cause of cost overruns in the early campus plan projects is rooted in mistakes made by management.[98] In addition, OEB staff can find no reference to a statement in the Supplemental Report that confirms OPG's position that the current cost of the project would be close to the original estimate if the original estimate had been properly developed. Therefore, OEB staff submits that 50% represents a reasonable approximation of the incremental cost of the AHS project resulting from OPGs management's imprudence (as opposed to poor estimating and scope changes). In other words, 50% of the incremental cost (as between the first execution release and the final amount) is related to a poor original estimate (for which OEB staff is not seeking a disallowance). The other 50% of the incremental cost is related to OPG's imprudent management for which a disallowance is necessary in order to ensure ratepayers are not paying imprudent costs incurred associated with the AHS project.

For the AHS project, the variance between the final estimated cost and cost set out in first execution business case summary is $61.5 million.[99] OEB staff is unsure of the exact dollar amount of the disallowance resulting from its submission (50% reduction of incremental capital cost) as a portion of the AHS project costs are related to removal

[96] Tr Vol 14 page 60
[97] AIC page 28
[98] Undertaking J15.3 Attachment 1 page 3
[99] Undertaking JT2.16. Calculated as $107.1 million (current estimate) minus $45.6 million (first execution business case)

and decommissioning costs that are not placed in rate base.[100] However, OEB staff estimates that the rate base disallowance proposed is about $28 million (and is calculated as the difference between the in-service amount forecast based on the original execution estimate and the in-service amount based on the final cost of the project).[101] If the OEB accepts OEB staff's proposal, it should require OPG, as part of the Draft Payment Order filing, to provide detailed evidence showing the removal of 50% of the incremental in-service amounts associated with the AHS project from rate base.

With respect to the OSB project, the asset was placed in-service in October 2015.[102] The first execution business case for the project estimated a total cost for the project of $47.8 million[103] and the final cost of the project is $62.7 million.[104] The in-service amount is $60.6 million (largely placed in service in 2015) based on the updated evidence.[105] A portion of the total $62.7 million cost of the OSB project is related to removal costs and therefore would not be reflected in the in-service amounts requested.[106]

The OSB project is an F&I project (or campus plan project) and was also managed by OPG's P&M group.[107] OEB staff submits that the same preliminary estimating and management issues that occurred during the completion of the AHS project, as discussed above, were also present in relation to the OSB project. Specifically, the contractor originally underestimated the effort required to complete the contract scope due to problems with the original design work. There were also additional scope changes required.[108] In addition, OPG noted that it could have performed better on the OSB project with respect to its own risk management activities.[109] Finally, in the Project

[100] Tr Vol 12 page 151
[101] OEB staff is unsure as to the exact in-service amount disallowance resulting from its submission. The reduction is likely in the range of $25 million to $31 million.
[102] Exh D2-1-3 Table 1, and Tr Vol 12 page 162
[103] Undertaking JT2.16. OEB staff notes that Exh L-4.2-AMPCO-17 Attachment 1 and Exh D2-1-3 Table 1 show that the original project estimate was $53.0 million. OEB staff is unsure which amount reflects the original estimate from the first execution business case summary.
[104] Exh D2-1-3 Table 1
[105] Undertaking JT2.16. OEB staff notes that Exh D2-1-3 page 10 states that the actual in-service amount for the AHS project is $58.7 million ($55.1 million in 2015 and $3.6 million in 2016). OEB staff is unsure which is the correct in-service amount associated with this project. OEB staff expects that the asset was largely placed in-service in 2015.
[106] Exh D2-1-3 Attachment 1, Tab 1 page 4
[107] Exh L-4.3-Staff-72 Attachment 22 pages 27-28
[108] Exh D2-1-3 Attachment 1 page 1
[109] Tr Vol 12 page 165

Over-Variance Approval form for the OSB, OPG's senior management commented that the handling of the project reflected "poor performance".[110]

Similar to the AHS, OEB staff submits that a portion of the incremental costs associated with the OSB project were caused by management failures (and the remainder was caused by poor estimation and necessary scope changes). OEB staff submits that 50% of the incremental capital cost (as between the original estimate and the final amount) for the OSB project should be disallowed from inclusion in rate base on a permanent basis for the same reasons as the AHS project.

The variance between the final cost and cost set out in first execution business case is $14.9 million.[111] OEB staff is unsure of the exact dollar amount of the disallowance resulting from its submission as a portion of the OSB project costs are related to removal costs that are not placed in rate base.[112] However, OEB staff estimates that the rate base disallowance proposed is about $7 million (and is calculated as the difference between the in-service amount forecast based on the original estimate and the in-service amount based on the final cost of the project).[113] If the OEB accepts OEB staff's proposal, it should require OPG, as part of the Draft Payment Order filing, to provide detailed evidence showing the removal of 50% of the incremental in-service amounts associated with the OSB project from rate base.

The permanent rate base disallowances proposed in this section related to the AHS and OSB projects should be considered incremental to the test period rate base reductions discussed in section 4.1.3. The permanent disallowances proposed by OEB staff in this section are due to the imprudent management of two projects that are either complete (OSB) or very near to completion (AHS). The test period rate base reductions discussed in section 4.1.3 are temporary in nature (as the actual prudent capital additions that occur during the test period will be included as part of the 2022 rate base amount) and reflect OEB's staff view that the updated test period capital addition forecast[114] is overstated.

OEB staff also notes that a more recent review of the work of the P&M group highlights that problems continued to exist with the group's ability to effectively manage projects in

[110] Exh D2-1-3 Attachment 1 page 5
[111] Undertaking JT2.16. Calculated as $62.7 million (current estimate) minus $47.8 million (first execution business case)
[112] Exh D2-1-3 Attachment 1 page 4
[113] OEB staff is unsure as to the exact in-service amount disallowance resulting from its submission. The reduction is likely in the range of $5 million to $8 million.
[114] Undertaking J21.1

2016. In the Project Controls Audit of the P&M group (the 2016 Audit), OPG, internally, assessed the design and operational effectiveness of project management controls implemented by the P&M group for its current portfolio of projects.[115] As part of the 2016 Audit, OPG sampled 13 projects (with six of those projects being in the execution phase at the time of the audit).[116]

SEC questioned OPG about the 2016 Audit at the oral hearing. For the six projects in the execution phase, the 2016 Audit noted that none of the projects had an estimate at completion based on a Class 3 high-confidence level estimate and detailed engineering work was being completed during the execution phase.[117] OPG stated that the more planning completed at the outset, the less likely issues will arise during the execution phase. OPG also indicated that there could be the need for rework and delays could occur on other aspects of the project if inadequate planning is completed at the outset.[118]

The 2016 Audit also noted that the Cost and Schedule Control Baselines (CSCBs) are the primary control for measuring cost and schedule performance of a project. The 2016 Audit highlighted that of the 13 projects sampled, five of the projects were deficient with respect to the cost and schedule control baselines (as the CSCBs for the three of the projects were not keeping pace with the CSCB baseline changes required and approved in business case summaries). In addition, two projects did not have CSCBs at all. The 2016 Audit stated that the impact of these deficiencies was potential cost increases and schedule delays.[119]

Finally, the 2016 Audit noted that a gating process for Asset Investment Steering Committee (AISC) portfolio projects, which are managed by the P&M group, has not been fully implemented.[120] The 2016 Audit noted that a gating process is meant to define a clear list of requirements, deliverables and expectations a project should follow in order to be granted approval to proceed to its next phase of a project's life cycle. A gating process also requires that a project be defined and the associated work scope be estimated to specified levels of accuracy. Not having a robust gating process creates the potential for cost increases and schedule delays due to insufficient oversight and control of project activities and objectives.[121] OPG agreed with SEC that due to the lack

[115] Undertaking J7.3 Attachment 1 page 3
[116] Undertaking J7.3 Attachment 1 page 13
[117] Undertaking J7.3 Attachment 1 page 7
[118] Tr Vol 14 pages 100-101
[119] Undertaking J7.3 Attachment 1 page 9
[120] Undertaking J7.3 Attachment 1 pages 3 and 11
[121] Undertaking J7.3 Attachment 1 page 11

of a robust gating process for the nuclear operations capital projects that have already gone into service, or are expected to come into service during the test period, it is possible that the costs may have been higher than they otherwise would have been if a proper gating process was in place at the outset (as earlier indication of problems allows for those problems to be mitigated more effectively).[122]

OEB staff notes that for at least two of the projects sampled in the execution phase (the Darlington Class II Uninterruptable Power Supply Replacement and the Fukushima Phase 1 Beyond Design Day Event Project) as part of the 2016 Audit, significant cost overruns (as between the first execution business case estimate and the most recent estimate) are expected at completion.[123] Both of these projects have in-service amounts forecast for the test period (based on the pre-filed evidence).[124]

OEB staff submits that the issues cited in the 2016 Audit, and discussed above, may be responsible for some of the cost overruns being experienced in relation to these two projects. If that is the case, a portion of the incremental capital costs associated with the projects should eventually be disallowed for inclusion in rate base on a permanent basis (as the 2016 Audit highlights imprudent management of these projects).

OEB staff notes, however, that the Darlington Class II Uninterruptable Power Supply Replacement project is in the very early stages (and will not be completed until 2023 based on the current forecast) and the Fukushima Phase 1 Beyond Design Day Event project while further along in its life cycle is still not near completion.[125] As these projects are not near completion, it is OEB staff's view that disallowances should not be made as part of the current proceeding as the actual final costs are not known and further information regarding OPG's management of the projects will likely be available after they are completed.

In the context of OEB staff's submission, set out in section 4.1.3, whereby the OEB would approve the forecast in-service amounts during the test period on an envelope basis (with no explicit approval of any cost overruns), the OEB will have the opportunity to review cost variances on the nuclear operations capital project at rebasing to determine whether incremental costs incurred are prudent and should be properly

[122] Tr Vol 14 pages 108, 111-112
[123] Exh L-4.2-AMPCO-17 Attachment 1. For the DN Class II Uninterruptable Power Supply Replacement, the original estimate was $38.4 million and latest estimate $55.1 million. For the Fukushima Phase 1 Beyond Design Day Event Project, the original estimate was $70 million and the latest estimate is $115.6 million.
[124] Exh D2-1-3 Table 1
[125] Tr Vol 14 page 107

included in rate base on a go-forward basis. OEB staff further submits that the OEB should identify these two specific projects as requiring further review at the rebasing that will take place after the projects are complete.

4.2 O. Reg. 53/05 Section 6(2)4 Projects

Issue 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?

4.2.1 Background

OPG requested that section 6(2)4 of O. Reg. 53/05, and the associated Capital Refurbishment Variance Account (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 Pickering Extended Operations 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.[126]

O. Reg. 53/05 states that:

> 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 [the prescribed generation facilities], 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.[127]

[126] Exh L-4.1-Staff-24 pages 1-2
[127] O. Reg. 53/05, section 6(2)4

The CRVA was established as a result of section 6(2)4 of O.Reg. 53/05.[128] As noted in the evidence of the first payment amounts proceeding[129], the CRVA was established for the interim period (i.e., April 1, 2005 to the date of the OEB's first 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.[130]

With respect to the Fuel Channel Life Management and Fuel Channel Life Extension projects, OPG stated that the projects have been previously accepted by the OEB as being subject to section 6(2)4 of O. Reg. 53/05 and nothing has changed with respect to these projects.[131]

OPG stated that the costs for the Pickering Extended Operations (including the Fuel Channel Life Assurance project) should also be subject to section 6(2)4 of O. Reg. 53/05 as the work will increase the output of Pickering. OPG noted that its proposed treatment of this project is consistent with the OEB's previously approved treatment of the Pickering Continued Operations (including the Fuel Channel Life Management project).[132]

Finally, OPG stated that the capital and non-capital costs of the Darlington Spacer Retrieval Tooling project should also be subject to section 6(2)4 of O. Reg. 53/05 as the project will increase the output of Darlington.[133]

4.2.2 OEB Staff Submission

OEB staff submits that the DRP and the other nuclear projects discussed above, as set out at OPG's updated response to an OEB staff interrogatory,[134] meet the requirements of section 6(2)4 of O. Reg. 53/05 and therefore CRVA treatment applies. OEB staff submits that the costs of these projects are incurred to increase the output of, refurbish or add operating capacity to a prescribed generation facility in accordance with section 6(2)4 of O. Reg. 53/05.

OEB staff agrees with the rationale presented by OPG regarding CRVA treatment for the Fuel Channel Life Management project, the Fuel Channel Life Extension project, the

[128] O. Reg. 53/05, section 6(2)4
[129] EB-2007-0905, Exh J1-1-1 page 7
[130] EB-2007-0905, Decision with Reasons, November 3, 2008 pages 122-123
[131] AIC page 23
[132] AIC page 23
[133] AIC page 24
[134] Exh L-4.1-Staff 24 pages 1-2

Pickering Extended Operations costs, and the Darlington Spacer Retrieval Tooling project.[135]

OEB staff also notes that section 6(2)4 of O. Reg. 53/05 expressly applies to the DRP; accordingly there is no question DRP costs qualify for CRVA treatment.

4.3 Darlington Refurbishment Program (DRP)

Issue 2.2 (Oral Hearing) – Are the amounts proposed for nuclear rate base for the Darlington Refurbishment Program appropriate?
Issue 4.3 (Oral Hearing) – Are the proposed nuclear capital expenditures and/or financial commitments for the Darlington Refurbishment Program reasonable?
Issue 4.5 (Primary) – Are the proposed test period in-service additions for the Darlington Refurbishment Program appropriate?

4.3.1 Summary of Request

OEB staff will provide its submissions on Issues 2.2, 4.3 and 4.5 in the section below as they are related issues.

OPG proposed a total budget for the DRP of $12.8 billion. This amount includes all of the definition and execution phase costs associated with the 4-unit refurbishment, the early in-service projects, the facility and infrastructure (F&I) projects, the safety improvement (SIO) projects, contingency, interest and escalation.[136] The $12.8 billion forecast cost for the DRP reflects the Release Quality Estimate (RQE) which is largely a Class 3 estimate as defined by the Association for the Advancement of Cost Engineering (AACE).[137]

As part of the current proceeding, OPG is seeking approval only for the in-service amounts associated with the Unit 2 refurbishment (including contingency, interest and escalation) along with the early in-service projects, the F&I projects, and the SIO projects. OPG is not seeking approval of the in-service amounts associated with the refurbishment of the three other Darlington units as part of this proceeding.[138]

[135] AIC pages 23-24
[136] Exh D2-2-8 pages 6-7
[137] Exh D2-2-8 page 3. More than 90% of the estimated costs of completion meet or exceed the level of estimate accuracy corresponding to a Class 3 estimate.
[138] Exh D2-2-1 page 6

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

Table 10
Bridge Year and Test Period In-Service Amounts ($ million)

	2016	2017	2018	2019	2020	2021	Total	Excluding Camp.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 Storage 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.

The total includes the Unit 2 related in-service amounts and the in-service amounts for the early in-service projects, F&I projects and SIO projects (described here as the “campus plan” projects).

The requested in-service amounts set out above include planned contingency for Unit 2, based on a P90 confidence level estimate, of $694 million,[139] and $46 million[140] of contingency for the F&IP and SIO projects (this amount reflects the removal of $30 million of contingency for the D2O project).[141]

OPG stated that if actual additions to rate base are different from forecast amounts, the cost impact of the difference will be recorded in the CRVA and any amounts greater than the forecast amounts added to rate base will be subject to a prudence review in a future proceeding.[142]

[139] Exh D2-2-8 page 9
[140] Exh D2-2-7 Chart 1. This reflects the entire planned contingency budget for the F&IP and SIO projects across the 4-unit DRP. Some of this contingency is likely not part of the in-service amounts requested in the current proceeding. OPG is invited to advise, in its reply submission, as to the amount of campus plan contingency that is included in the requested in-service amounts.
[141] Exh L-4.3-AMPCO-076, Attachment 2 page 9
[142] Exh A1-2-2 pages 4-5

The proposed rate base related to the DRP, updated to reflect the removal of the D2O in-service capital amounts, is set out in the following table.[143]

Table 11
Bridge Year and Test Period DRP Net Plant ($million)

	2016	2017	2018	2019	2020	2021
DRP Net Plant	419.1	611.9	601.5	586.7	4,699.1	5,154.5

The same methodology used to determine the non-DRP net plant values was used to determine the DRP net plant values.[144]

4.3.2 Summary of OEB Staff Submission

OEB staff submits that only the DRP-related capital for which there are in-service amounts proposed for the test period or for which amounts have previously gone into service (and were not previously approved by the OEB) should be reviewed and considered for approval by the OEB as part of the current proceeding. While OEB staff recognizes that the Unit 2 refurbishment is appropriately considered as part of the overall DRP, only the costs directly associated with Unit 2 (and the early-in service, F&I, and SIO projects) are in scope for approval by the OEB as part of this proceeding.

The DRP-related capital expenditures associated with assets that are expected to come into service after 2021 will be the subject of a future proceeding and the OEB should not make any findings with regard to those costs as part of this case. OEB staff submits that the OEB should review those future DRP-related project costs in the context of the evidence filed at that time. If the Province decides not to move forward with the refurbishment of any of the other Darlington nuclear units, the committed costs and demobilization costs associated with discontinuing the DRP would be reviewed at the time that those costs are brought forward for approval by the OEB.

OEB staff will focus its submissions related to the DRP on the reasonableness of the in-service amounts for which OPG seeks approval as part of the current proceeding. The analysis includes a consideration of the overall planning and contracting strategies employed by OPG for the entire four-unit DRP as an understanding of those activities is necessary to determine the reasonableness of the Unit 2 spending.

[143] Exh B3-1-1 Table 1, and Exh N2-1-1 page 4
[144] AIC page 17. OEB staff has discussed this issue further in section 4.1.1

With respect to the in-service amounts for Unit 2, the early-in service projects, F&I projects, and SIO projects, OEB staff accepts the proposed additions to rate base with the following adjustments:

- Removal of the incremental in-service amounts associated with the Third Emergency Power Generator project between the first execution release and the applied for in-service amount. OEB staff estimates that this proposal, if accepted, would result in an approximate $25 million reduction to the 2016 in-service amount.

- 13% reduction to the labour costs (all of which are capitalized) associated with the Project Management and Oversight functions, which form part of the overall in-service amounts requested over the test period. OEB staff estimates that this proposal, if accepted, would result in an approximate $100 million reduction to the proposed in-service amounts.

- Removal of $144 million of contingency from the proposed in-service amounts associated with Unit 2 to reflect the working schedule (P37 confidence level).

If the OEB accepts the proposed reductions to the in-service amounts, changes to the rate base and the related revenue requirement would be necessary.

The rationale for the above submissions and OEB staff's position on the treatment of variances between forecast and actual DRP-related in-service amounts is discussed in the sections that follow.

4.3.3 Applicable Regulatory Framework

Background

As discussed in OPG's evidence, amendments were made to O. Reg. 53/05 effective January 1, 2016 to include certain provisions that deal with nuclear refurbishment costs and to define the scope of the OEB's jurisdiction in considering OPG's Application.[145]

The first additional provision in O. Reg. 53/05 is associated with the need for the DRP. O. Reg. 53/05 states:

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[145] Exh D2-2-1 pages 9-10

> 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.[146]

O. Reg. 53/05 also stipulates that if the OEB is satisfied that the 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 incurred related to the DRP.[147]

There are also certain provisions included as part of O. Reg. 53/05 associated with rate smoothing.[148]

OEB Staff Submission

By virtue of the regulation, the need for the DRP is outside the scope of this proceeding and the OEB's jurisdiction.

OEB staff set out its submissions regarding the prudence review in section 4.3.9 with respect to the treatment of DRP-related costs recorded in the CRVA.

OEB staff's submission on rate smoothing is set out at section 11.4.

4.3.4 Planning and the Capacity for Execution

Background

OPG heavily invested in its planning activities for the DRP. OPG commenced the definition phase for the DRP in 2010 and it concluded in 2015 with OPG's board of directors' approval of the RQE. In the definition phase, OPG completed: (a) scope definition; (b) incorporation of lessons learned in the program planning; (c) detailed engineering for all Unit 2 scope and modifications to be completed within the DRP; (d) reactor mock-up, tool fabrication and testing; (e) cost estimation of the DRP in accordance with a Class 3 Estimate (as defined by AACE); and (f) a Level 2 schedule for the entire DRP and a Level 3 schedule for Unit 2 execution.[149]

[146] O. Reg. 53/05, section 6(2)12(v)
[147] O. Reg. 53/05, section 6(2)4
[148] O. Reg. 53/05, section 5(5) and section 6(2)12(i-iv)
[149] Exh D2-2-4 pages 2-3

With respect to its contracting strategy, OPG is using a multi-prime contractor model for the DRP. Under this model, OPG has a separate contract with each contractor that is performing work on the DRP. Each contractor has responsibility for completion of work that is within the scope of its specific contract while OPG oversees and is responsible for the entire program.[150] OPG awarded all of the major contracts, in accordance with its contracting strategy, during the definition phase of the DRP.

OPG stated that the key benefit of the multi-prime contractor model is that OPG maintains control over the entire DRP, including the deliverables, costs and schedule. While maintaining control of the DRP, OPG is also able to assign risks to the parties that are in the best position to manage those risks. Overall, OPG believes that the contracting framework that it has put in place will allow for a reasonable balance of risk transfer to contractors and the costs of the contracted services.[151]

OPG noted that it established an organizational structure dedicated to overseeing the execution of the DRP as it maintains control of the entire project. The organizational structure has two primary aspects: (1) dedicated project management teams that are responsible for the management, oversight and delivery of specific work bundles; and (2) functional support groups that will support the major work bundles and the integration of work across the DRP.[152]

OPG also stated that it implemented effective measures to ensure that the execution of the DRP goes to plan. OPG noted that the measures include: (a) execution management; (b) direct incentives for OPG; (c) independent oversight; and (d) appropriate reporting to stakeholders.[153]

OEB Staff Submission

Both Pegasus-Global Holdings Inc. (Pegasus) (OPG's expert) and Schiff Hardin LLP (OEB staff's expert) agreed that OPG's planning for the DRP is consistent with industry standards.[154] OEB staff generally agrees with the testimony of both experts.

More specifically, OEB staff agrees with Schiff Hardin's findings that: (a) OPG has developed adequate project control systems to manage the cost and schedule of the DRP; (b) OPG's planned project management policies and procedures establish a

[150] Exh D2-2-2 page 1
[151] Exh D2-2-2 page 2
[152] Exh D2-2-2 page 3
[153] AIC page 58
[154] Exh D2-2-11 Attachment 3, and Exh M1

reasonable basis for overseeing the completion of the DRP; and (c) OPG adequately performed risk assessment for the project and put in place the necessary processes to address risks as they arise.[155] Pegasus made similar findings in its testimony at Exh D2-2-11, Attachment 3.

Concentric Energy Advisors (Concentric) stated that the contracting strategies that OPG is employing are appropriate and meet the regulatory standard of prudence.[156] Schiff Hardin also stated that the multi-prime contracting strategy developed and applied by OPG meets industry standards.[157] However, Schiff Hardin noted that for an owner-led multi-prime strategy to be successful on a mega-project, the owner must employ a strong, capable, and experienced project management team. Otherwise the multi-prime approach is likely to miss important schedule and cost objectives.[158] Schiff Hardin also stated that one of the risks of OPG's multi-prime approach is that the SNC / AECON joint venture is performing work under three separate contracts and if one, or both, members of the joint venture defaults, three of the major scopes of work for the DRP would be adversely impacted.[159]

OEB staff accepts that the multi-prime contractor model is appropriate for the DRP. OEB staff is of the view that the strategy applied by OPG is a reasonable approach for a project of the size and complexity of the DRP. However, as explained by Schiff Hardin, it is not without risk.[160]

OEB staff also agrees with the testimony of Pegasus regarding the review of OPG's execution approach. OPG has put in place a strong organization comprised of qualified project managers to execute the project. In addition, the content and scope of OPG's program and project management plans are in accordance with industry best practices.[161] OPG has also established strong cost management procedures to monitor investment in the program against a baseline.[162] Finally, OPG has established appropriate practices in accordance with industry standards to identify and mitigate risks as they occur during the execution phase of the DRP.[163]

[155] Exh M1 page 7
[156] Exh D2-2-2 Attachment 1 page 4
[157] Exh M1 page 34
[158] Exh M1 page 34
[159] Exh M1 page 39
[160] Exh M1 pages 34 and 39
[161] Exh D2-2-11 Attachment 3 page 44
[162] Exh D2-2-11 Attachment 3 page 57
[163] Exh D2-2-11 Attachment 3 page 72

OEB staff submits that OPG has planned effectively and has implemented an appropriate framework that provides it with the capacity to execute the DRP successfully. The company is quite properly treating the DRP as a “destiny project”, and there appears to be a corresponding sense of internal accountability: OPG’s CEO told the OEB that he considers his job to be on the line.[164] Furthermore, OEB staff agrees with the testimony of Schiff Hardin that OPG’s detailed planning during the definition phase of the DRP mitigates some of the risk that may arise during the execution phase. However, no amount of planning is a guarantee of successful completion.[165]

OPG’s biggest test will come during the execution phase, which is now underway. As explained by Schiff Hardin, all mega-projects experience some form of cost and/or schedule issues. It is not a question of whether these types of events occur, it is a matter of how OPG handles and responds to these issues when they arise.[166]

OEB staff submits that successfully planning for the DRP and establishing a strong execution approach does not mean that the DRP, in the end, will inevitably be executed in a prudent manner. Therefore, OEB staff submits that the OEB should conduct a detailed review of the execution phase of the DRP at the time that OPG brings forward any amounts recorded in the CRVA for disposition. As discussed by Schiff Hardin, the prudence evaluation should to consider all of the management decisions over the execution of the project to determine whether those decisions were reasonable.[167] Additional details regarding OEB staff’s proposal for the framework for review of the CRVA are set out in section 4.3.9 of this submission.

4.3.5 Updated Forecast for In-Service Amounts

Background

OPG provided updates to the in-service dates and in-service amounts for a number of its early in-service projects, SIO projects, and F&I projects. The update highlights that a number of these projects are complete (or near completion) and that the estimated in-service amounts have reduced for some projects and increased for others.[168] In addition, the forecast in-service amounts associated with Unit 2 were updated by OPG

[164] Tr Vol 1 page 41
[165] Exh M1 page 8
[166] Exh M1 page 8
[167] Exh M1 page 11.
[168] Undertaking J2.6

in the Unit 2 Execution Estimate (U2EE). Unit 2 is still in the early stages of the execution phase with an expected in-service date of February 2020.[169]

OPG stated that it is not seeking any changes to its requested in-service amounts (and the timing of those in-service additions) related to any of the updates discussed above. OPG noted that the only change to the in-service amounts is associated with the removal of the D2O Project as discussed in the Second Impact Statement.[170]

OEB Staff Submission

OEB staff submits that it is appropriate for the OEB to approve the forecast in-service amounts and in-service dates as originally filed for the DRP assets (both Unit 2 and the other DRP-related projects) with the exception of: (a) the removal of the in-service amounts associated with the D2O Project as proposed by OPG; (b) the removal of incremental in-service amounts associated with the Third Emergency Power Generator project as proposed by OEB staff below; (c) the capitalized labour cost reduction proposed by OEB staff in section 4.3.7; and (d) the contingency reduction proposed by OEB staff in section 4.3.8.

In a situation like this, where there is more recent information available regarding expected in-service dates and amounts, the OEB typically requires that the best available information be used to determine the appropriate timing and quantum of capital additions. However, a different treatment can be applied to the DRP assets due to the applicability of the CRVA. The CRVA will ensure that the revenue requirement impact of changes to in-service dates between forecast and actual will be appropriately tracked for future refund to or collection from ratepayers. In addition, in the context of OEB staff's submission on the treatment of DRP-related costs in the CRVA, set out at section 4.3.9, at the time that the CRVA is brought forward for disposition the OEB will have the opportunity to review, in detail, the prudence of any overspending relative to the in-service amounts. This is the appropriate time for the OEB to review variances between forecast and actual in-service amounts as a more comprehensive understanding of the drivers of any overspending will be available.

However, there is one SIO project for which OEB staff submits that the OEB should not approve the in-service amount as proposed in the pre-filed evidence at this time. The

[169] Undertaking J4.5
[170] Exh N2-2-1; Undertaking J5.2 page 2; and Tr Vol 5 pages 57-58.

Third Emergency Power Generator project had an initial full release of $77.2 million.[171] The total cost of the project as set out in the original filing is $120.4 million (with $105.3 million of that amount proposed to be placed in-service in 2016).[172] The most recent forecast of the in-service amount for the project is $139.6 million.[173] The in-service date for the project based on the pre-filed evidence was October 2016.[174] The most recent forecast of the in-service date is March 2017.[175]

On the basis of OEB staff's submission above whereby the DRP-related in-service amounts proposed in the pre-filed evidence would be approved by the OEB, a prudence review for only the difference between the requested in-service amount ($105.3 million) and the actual in-service amount (currently forecast at $139.6 million) would be available to the OEB. In other words, the OEB would forgo the opportunity to consider whether the cost variance between the initial execution estimate and the proposed in-service amount (set out in the pre-filed evidence) was prudently incurred. OEB staff submits that this is not appropriate as there very well could be management imprudence that caused a portion of the cost overrun experienced. Therefore, in order to ensure that the OEB has the benefit of a full prudence review of this project (with the ability to disallow all costs in excess of the first execution estimate), the OEB should approve a 2016 in-service amount that reflects only the first execution estimate. The variance between the initial estimate and the final cost for the project should be reviewed at the time that the CRVA is brought forward for disposition to determine whether the incremental spending was prudently incurred.[176]

For the above reasons, the in-service amount related to the Third Emergency Power Generator project should be reduced by an estimated $25 million.[177]

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[171] Exh D2-2-10 Table 2. OEB staff is unsure whether $77.2 million is the original execution release or $88.2 million is the original execution release as set out in Exh L-5.3-AMPCO-30 at p. 3 Chart 3. OEB staff is also unsure whether the execution release reflects entirely rate base amounts (or if there are removal type costs also included).
[172] Exh D2-2-10 Table 2
[173] Undertaking J2.6 Attachment 1 page 1
[174] Exh D2-2-10 Table 2
[175] Undertaking J2.6 Attachment 1 page 1
[176] Tr Vol 14 page 60. As discussed in section 4.1.4, OPG uses the first execution release to measure its own performance. OEB staff submits that the OEB should use the first execution estimate to measure cost variances.
[177] As noted previously, OEB staff is unsure as to the exact in-service amount associated with the first execution estimate for the Third Emergency Generator project. OEB staff submits that the reduction should be calculated as the difference between the proposed 2016 in-service amount of $105.3 million and the in-service amount associated with what OPG considers the first execution estimate. The reduction is likely in the range of $17 million to $30 million.

4.3.6 Early In-Service Projects and Other Common Projects – Assignment of In-Service Amounts

Background

OPG provided a table highlighting the DRP-related capital projects that are expected to enter into service prior to the completion of Unit 2.[178] The projects include the early in-service projects, F&I projects and SIO projects. OPG noted that these projects become immediately used and useful to OPG's nuclear operations once they are completed. OPG stated that placing these projects in-service at the time of their completion is in accordance with US generally accepted accounting principles.[179]

OPG also set out the projects that are common to two or more of the Darlington units that it has proposed to close to rate base with Unit 2. OPG stated that the common projects will be used or useful at the time that Unit 2 is returned to service because they are necessary, in their entirety, for the Unit 2 refurbishment. OPG provided specific rationale for each of the common projects supporting the assignment of the in-service amount to Unit 2.[180]

OEB Staff Submission

OEB staff submits that it is appropriate for the early in-service projects, F&I projects and SIO projects as set out at Exh D2-2-10, Tables 2 and 3 to be placed in-service at the time of their completion. As OPG explained, these projects are used and useful by OPG's existing nuclear operations ahead of the completion of Unit 2. Therefore, in accordance with the applicable regulatory principles it is appropriate that they be placed in service at the time of completion (and in advance of Unit 2).

In regard to the common projects listed in Undertaking J2.9, OEB staff supports OPG's proposal to place these assets in service at the same time as Unit 2. While these common projects may also be necessary and/or beneficial to the refurbishment of future units, they are used and useful at the time that Unit 2 enters service. Therefore, from a regulatory perspective, it is appropriate they be placed in service at the same time as Unit 2.

[178] Exh D2-2-10, Tables 2-3.
[179] Undertaking J2.9 page 1.
[180] Undertaking J2.9 at pages 1-2.

4.3.7 Project Management and Oversight Costs – OPG Labour and Managed Task Services

Background

OPG has elected to use a multi-prime contractor model for the DRP. OPG retains control over the entire DRP, including the deliverables, costs and schedule. Therefore, OPG has the responsibility to perform Project Management and Oversight type functions across the numerous aspects of the DRP.[181]

The Unit 2 capital costs requested to be placed in service during the test period include capitalized labour costs incurred by OPG (both OPG staff and Managed Task Services – MTS[182]) to fulfill Project Management and Oversight functions. For 2017, the planned labour cost for Project Management and Oversight functions is $198 million.[183]

OEB Staff Submission

In its 2013-2015 Business Plan, OPG provided the 2013, 2014 and 2015 planned OPG headcount for the DRP (247, 266, and 276 respectively).[184] The actual OPG headcount for the DRP for the same period was 181, 189 and 237 respectively.[185]

OPG stated that while it has historically been understaffed compared to plan, the staffing shortfall is offset by the availability of labour under contract (through MTS).[186]

OEB staff notes that, in 2016, the planned labour costs for Project Management and Oversight functions was $209 million and the actual cost was $181 million (13.4% underspend relative to budget).[187] These amounts include both OPG's own labour costs and costs associated with contract employees (procured through OPG's MTS arrangements).[188] Therefore, in 2016, even when including the contracted labour costs, OPG continued to spend less than forecast to fulfill Project Management and Oversight functions.

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[181] Exh D2-2-2 pages 3-4
[182] MTS costs include Owner Support Services and other similar contracts.
[183] Undertaking J4.4 page 2
[184] EB-2013-0321, Exh A2-2-1 Attachment 1 page 7
[185] Exh A2-2-1, Attachment 1 page 27
[186] Tr Vol 4 page 66
[187] Undertaking J4.4 page 2
[188] The amounts set out in the undertaking also include the associated interest and escalation. Undertaking J4.4.

The reduced spending on these functions relative to forecast is further supported by a statement in the Management Report to the Darlington Refurbishment Committee. In that report, it is noted that the life-to-date costs of the DRP were below plan and one of the primary contributors to that under-spending is “lower than planned OPG resources.”[189]

OEB staff submits that actual DRP labour spending has consistently been below forecast. The labour costs incurred in 2016 were $28 million, or 13.4%, below planned for Project Management and Oversight functions. OEB staff notes that in 2016 the entire variance between planned and actual was associated with the Project Management function.[190] However, OEB staff submits that this may not be the case going forward.

As of January 2017, OPG was 186 FTEs short of its planned staffing level (905 actual compared to 1,091 planned), which reflects a 17% staffing shortage.[191] OEB staff understands that some portion of this shortage could be met through the use of contract labour as discussed by OPG.[192] However, this represents a significant shortfall relative to plan going into the year where the work required to complete the DRP is increasing significantly. OEB staff submits that the continued staffing shortfall leads to some concerns that the forecast labour costs are overstated.

OEB staff submits that it is not appropriate to approve for addition to rate base the entirety of forecast amounts that have been historically overstated and where there continues to be a clear staffing shortage for DRP (at least with respect to OPG’s own staffing levels).

OEB staff submits that the OEB should order a reduction of 13% to the total requested in-service amounts associated with labour costs (including the related interest and escalation cost forecasts) for the Project Management and Oversight functions for the DRP during the test period. This reduction is consistent with the under-spending for labour associated with the Project Management and Oversight functions in 2016. OEB staff submits that it is appropriate to apply the reduction to both the Project Management and Oversight functions as the under-spending could occur in either category going forward during the test period.

[189] Undertaking J2.10, Attachment 1 page 3
[190] The actual 2016 planned and actual labour costs for the Oversight function were both $97M. The 2016 planned Project Management cost was $112M and the actual was $84M (which represents a variance of $28M or 25%). Undertaking J4.4
[191] Undertaking J3.3
[192] Tr Vol 4 page 66

If the OEB agrees with OEB staff's submission, the OEB should order OPG to provide detailed evidence as part of its Draft Payment Amounts Order that shows the 13% reduction to the labour costs associated with the Project Management and Oversight functions being applied to the DRP-related in-service amounts requested for the test period. OEB staff estimates, based on the 2017 planned labour costs associated with the Project Management and Oversight functions (including MTS), that this would result in an overall reduction of about $100 million to the in-service amount over the test period (and largely applied to the proposed 2020 in-service amount).[193]

As an alternative, the OEB may want to consider a smaller reduction to the total requested in-service amounts associated with labour for the Project Management and Oversight functions for the DRP during the test period. The OEB could consider a 6.5% reduction to the in-service amount over the test period (which staff estimates would be about $50 million).[194] The smaller reduction can be rationalized on the basis that there is a difference between the definition and execution phases of the DRP. In the execution phase, the significant under-staffing that OPG has historically experienced may not persist to the same extent.

OEB staff submits that ratepayers should not be burdened during the test period with excess labour costs resulting from a forecast that has been historically overstated. A reduction of the magnitude proposed by OEB staff will reduce the potential variance between planned and actual. However, OEB staff notes that variances in these labour costs, like all of the other DRP-related costs, will be subject to a review by the OEB when the CRVA is brought forward for disposition. If there are labour costs incurred for Project Management and Oversight functions in excess of the amounts approved as in-service additions during the test period, OPG will have the opportunity to explain why it was appropriate for the costs to be incurred and seek recovery of these incremental costs at the time that the CRVA is reviewed.

OEB staff submits that there should be transparent reporting of the actual labour costs (and associated in-service amounts) incurred for Project Management and Oversight functions for the DRP during the test period, which should be provided to the OEB at the time that the CRVA is brought forward for disposition. The actual labour costs for these activities will be compared to the baseline reporting proposed by OEB staff in section 4.3.12.

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[193] A 13% reduction to the 2017 planned labour costs for Project Management and Oversight functions is approximately $26 million. Therefore, in the four years of the test period to 2020 (when Unit 2 will be placed in service), assuming an equal spending on labour costs for Project Management and Oversight functions, the total reduction is about $100 million.
[194] This is calculated in the same manner as the proposed 13% reduction.

4.3.8 Unit 2 Contingency

Background

OPG stated that "contingency refers to amounts that are expected to be expended because there are risk items and uncertainties that will occur and cannot be entirely mitigated or avoided."[195] This definition is used by the AACE.[196]

OPG further stated in its Nuclear Projects Risk Management Manual that:

> Contingency is a tool to manage uncertainty and risk throughout the life of a project. The contingency reserve should be proportional to the project size, duration, complexity, risk exposure and tolerance, prior experience with the work, and confidence levels set by management. ***Contingency is not a tool to compensate for an underdeveloped project plan.***
>
> Contingency covers the *known unknowns* in a project. Specifically, these are the uncertainties associated with a schedule and cost estimate, as well as the discrete risk events that impact the objectives defined by these fundamental products.[197]

OPG developed the contingency estimate through a detailed evaluation of the: (a) uncertainties in estimating cost and schedule for the DRP; (b) discrete risks relating to cost and schedule; and (c) contingent work across each project and the entire DRP. OPG noted that its evaluation relied upon the use of both qualitative and quantitative methods, including performance of an integrated cost and schedule Monte Carlo simulation.[198]

OPG's contingency forecast resulting from its evaluation and the use of the Monte Carlo model is at a P90 confidence level. A P90 confidence level means that there is a 90% confidence that the contingency value is sufficient to cover the risks and uncertainties that were included in the model.[199] From a statistical standpoint, a contingency forecast established at a P90 confidence level means that there is a 90% chance that the actual required contingency will be less than the estimated amount.[200]

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[195] Exh D2-2-7 page 1.
[196] Exh D2-2-7 Footnote 1.
[197] Exh L-4.3-Staff-048 Attachment 24 pages 17 and 18 (emphasis in original)
[198] Exh D2-2-7 page 6
[199] Exh D2-2-9, Attachment 2 page 20
[200] Exh D2-2-7, Attachment 1 page 3

OPG provided the following list of “low probability, high consequence events” that the company did not consider in establishing its contingency estimate:

- a significant labour disruption
- changes in the political environment
- an international nuclear accident (Fukushima-type event) or incident
- unforeseen changes to financial and other economic factors beyond those assumed in the DRP
- an unforeseen natural disaster (e.g., tornado, earthquake, hurricane)
- a world event (e.g., September 11, 2001-type event) which causes a significant escalation in security, affecting access to the plant and productivity
- a failure of the information technology infrastructure (outside of OPG)
- societal breakdown / war / civil disruption[201]

Overall, OPG forecasted $1.7 billion of contingency across the 4-unit DRP based on its P90 level estimate. It also provided contingency estimates at different confidence levels as set out in the following table:

Table 12
Four Unit DRP Contingency Amounts

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

OPG allocated $694 million of the total DRP contingency (approximately 40%) at the P90 confidence level to Unit 2.[202] The proposed contingency is reflected as part of the in-service amounts requested for Unit 2.[203]

OPG noted that the allocation of the contingency estimate across the four units was based on the anticipated timing for when the risks and uncertainties would be realized and the associated contingency costs would be incurred. OPG stated that, based on industry experience, the first unit of a refurbishment project realizes more risks than subsequent units. Therefore, OPG determined that 40% of the total DRP contingency forecast is appropriately allocated to Unit 2 with the expectation that lower levels of contingency will be required for future units.[204]

[201] Exh L-4.3-EP-13
[202] Exh D2-2-7 pages 7-8
[203] Exh D2-2-8 page 9
[204] Exh D2-2-7 pages 7-8

OPG also provided, in response to an undertaking, the contingency for Unit 2 associated with its working schedule. The working schedule for Unit 2 is 35 months (compared to 40 months for the high confidence schedule).[205] The working schedule duration is equivalent to a confidence level of P37.

OPG noted that the working schedule is intended to be aggressive. However, OPG is managing the work on Unit 2 to the working schedule in order to allow for early identification of risks so that mitigating actions can be taken promptly. Essentially, the working schedule is the target schedule for the Unit 2 refurbishment. On the basis of completing the Unit 2 refurbishment in accordance with the working schedule, the contingency would be reduced by $144 million (and the Unit 2 in-service amount would be reduced to $4.656 billion).[206]

There is also contingency spending (both actual and forecast) reflected in the in-service amounts for the F&IP and SIO projects.[207] In addition, there is contractor-level contingency built into the target-price and fixed-price contracts.[208]

In its AIC, OPG reiterated that contingency is an important tool for managing uncertainty and risk throughout the life of a project. OPG stated that contingency refers to an amount that it anticipates spending because there are risk items and uncertainties that will occur and cannot be entirely mitigated or avoided.[209]

OPG's expert, Pegasus, supported OPG's contingency estimate. Pegasus noted the $1.7 billion contingency estimate for the DRP is reasonable based on the thorough risk assessment and Monte Carlo analysis undertaken by OPG. Pegasus further stated that, while there is no specific confidence level considered as best practice, a P90 confidence level provides OPG with a high probability of completing the DRP within its $12.8 billion estimate. Overall, Pegasus found that OPG's cost and schedule contingency development aligns with industry standards.[210] OEB staff's expert, Schiff Hardin, agreed with Pegasus that the use of a P90 estimate is within industry standards.[211]

OEB Staff Submission

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[205] Tr Vol 1 page 14.
[206] Undertaking J2.2
[207] Tr Vol 5 pages 28-29
[208] The contingency included in the target price contracts is at a P50 level and the amount included in the fixed-price contracts is not defined. Tr Vol 5 page 37
[209] AIC page 53
[210] Exh D2-2-11, Attachment 3 pages 7-9
[211] Tr Vol 7 page 60

OEB staff submits that the OEB should approve only in-service amounts for Unit 2 contingency based on OPG's working schedule (which reflects a P37 confidence level). The result of reducing the contingency to reflect a P37 confidence level is a $144 million reduction to the Unit 2 related in-service amounts requested for the test period.[212]

It is OEB staff's position that the need for contingency amounts should be considered differently from a planning / project management perspective and a ratemaking perspective.

From a planning perspective, OEB staff understands the need for a high confidence level estimate (P90) (including sufficient contingency to cover the costs of risks and uncertainties that may arise). It was appropriate for OPG to develop a schedule and cost estimate that it could rely on at high degree of confidence in order to provide conservative estimates of the cost and economics of the project to its shareholder and to ensure that the necessary resources are available for the DRP in a variety of different scenarios. The need for contingency from a planning and project management perspective was supported by OPG's expert. However, Pegasus did not opine on the regulatory treatment of the contingency budget.[213]

Similarly, although OPG notes, in its AIC, that Schiff Hardin explained in cross-examination that using a P90 confidence level is "prudent", it does not follow that the OEB should approve the contingency associated with the P90 estimate in this proceeding.[214] It goes without saying that any project manager would prefer a higher level of confidence over a lower one. But from a regulatory point of view, it would not be in the public interest to approve the full amount of the P90 contingency. Doing so in this case would mean OPG would have a 90% chance of over-recovering its Unit 2 costs through payment amounts in the test period. Although ratepayers would eventually recover any overpayments through the CRVA, ratepayers would effectively be overpaying for a period of five years.[215] A proposal for recovery of costs that creates a 90% chance of customer over-payment seems to be at odds with established principles of ratemaking. In this case, OPG's request for the P90 contingency amounts is especially objectionable considering the regulatory requirement for the OEB to smooth weighted average payment amounts, as discussed in section 11.4. OPG is, on the one hand, asking for contingency amounts of which it will in all likelihood (90%) not require

[212] Undertaking J2.2
[213] Exh D2-2-11, Attachment 3 pages 7-9; and Tr Vol 5 page 159
[214] AIC page 57
[215] Tr Vol 1 page 36

all, while on the other hand asking for about $1 billion of revenue to be deferred beyond the test period, with interest.

From a ratemaking perspective, in the context of the applicability of CRVA treatment to capital cost variances to the DRP, OEB staff submits that there is no reason that OPG requires that contingency amounts at a P90 confidence level for Unit 2 be approved by the OEB at the outset as part of the proposed capital additions.

OEB staff submits that the DRP is different from many other capital projects that are brought before the OEB for approval due to the applicability of the CRVA. For major capital projects, where there is no variance account treatment available during the test period, the utility is required to forgo the recovery of revenue requirement on any cost variances until such time that it brings forward a rebasing application. In this case, with respect to the DRP assets, if there are actual in-service amounts incremental to the amount approved, OPG will be allowed to record the revenue requirement impact of those capital variances during the test period in the CRVA for eventual recovery from ratepayers. In other words, if, on an actual basis, OPG does need to spend its entire planned contingency budget ($694 million) for Unit 2 over the course of the refurbishment, and that spending is deemed prudent by the OEB, OPG will be made whole and will recover the entire revenue requirement of the incremental capital spending as if those capital costs were placed in-service at the outset.

OEB staff submits that the execution of the work on Unit 2 is in the very early stages. As the refurbishment progresses there will likely be a number of risks and / or uncertainties that actually come to realization while others do not. Pegasus also stated in its expert evidence, “OPG’s policies dictate that drawdown of contingency will be avoided whenever possible through the effective management and mitigation of risks and trends.”[216] Therefore, some of the risks and / or uncertainties may in the end be avoided, or the cost impacts reduced, due to OPG’s actions to mitigate those risks. In addition, OEB staff submits that there may be savings opportunities that arise during the execution phase of the DRP that could further offset the requirement to use contingency.[217]

Overall, OEB staff agrees that it is important that OPG has evaluated the risks that may occur during the refurbishment of Unit 2 and budgeted for contingency to address the potential risks at a high confidence level. It is crucial from a planning and project

[216] Exh D2-2-11, Attachment 3 page 58
[217] Tr Vol 3 pages 53-54. OPG stated that it logs opportunities to reduce costs of a delivery as they arise in its risk register.

management perspective that OPG is aware of the risks and uncertainties applicable to Unit 2 so it can react appropriately to those risks if they do occur. However, OEB staff submits, from a ratemaking perspective, the OEB should approve only contingency amounts that reflect the schedule that OPG is actually working towards achieving. There is no reason that, at the outset, in the context of the availability of the CRVA to true-up actual contingency costs incurred, the OEB should approve contingency amounts that are incremental to what is necessary for OPG to meet its own working (or target) schedule. Therefore, OEB staff submits that the OEB should reduce the proposed in-service contingency amount by $144 million to reflect the contingency associated with OPG's working schedule (which is equivalent to a confidence level of P37).

OEB staff also submits that OPG should be required to report its actual in-service amounts associated with contingency spending separately from the base in-service amounts (with an explanation as to how and why the contingency amounts were spent) at the time of the CRVA review. Schiff Hardin noted that this type of detailed contingency reporting has been required by commissions in other jurisdictions.[218] The actual contingency spending will be compared to the baseline reporting suggested by OEB staff in section 4.3.9.

In regard to the early in-service, F&I projects and SIO projects for which OPG seeks approval of the in-service amounts as part of the current proceeding, OEB staff notes that the execution of these projects, for the most part, are in much later stages of development than Unit 2. A number of the projects are complete or, at least, very near to completion.[219] For many of these projects, the contingency spending included as part of the requested in-service amount has been utilized to address actual risks and uncertainties that arose during the execution of the projects. Therefore, removing the contingency amounts associated with these projects from the proposed in-service amounts is not reasonable. In accordance with OEB staff's submission in section 4.3.5, OEB staff submits that the in-service amounts requested in the original filing (as proposed by OPG) associated with these assets[220] should be approved by the OEB and any variances between the originally filed amounts and the final actual amounts should be reviewed as part of the CRVA review.

Finally, OEB staff submits that the contingency amounts reflected in the target-price and fixed-price contracts should be approved as filed. The contractor-level contingency

[218] Tr Vol 7 pages 52-53
[219] Undertaking J2.6
[220] With the exception of the Third Emergency Power Generator project.

costs are built into the contracts signed by OPG[221] and OEB staff is not proposing any changes to those contracts.

4.3.9 Treatment of DRP Related Costs in the CRVA

Background

In accordance with section 6(2)4 of O. Reg. 53/05, the OEB previously approved the CRVA to record variances between the actual and forecast capital and non-capital costs and firm financial commitments incurred to increase the capacity, refurbish or add operating capacity to a prescribed nuclear facility.[222]

The CRVA is applicable to the DRP-related capital and non-capital costs (along with a few other nuclear projects). As discussed previously, OPG is seeking approval for in-service amounts in this proceeding of $5.177 billion ($4.8 billion for the Unit 2 refurbishment and $377.2 million for the campus plan projects). CRVA treatment is applicable to all of these DRP-related capital costs and also the non-capital costs discussed in section 4.3.11.

For the 2017-2021 period, variances in nuclear revenue requirement resulting from variances in DRP in-service additions (as well as DRP OM&A expenses) will be recorded in the CRVA. OPG will file an application to dispose of any balances in the CRVA in a future proceeding.[223]

OPG stated that it intends to complete the Unit 2 refurbishment and return Unit 2 to service within the total $4.8 billion budget based on the RQE. OPG further stated that, to the extent that there are any variances, the overall 4-unit DRP will be completed within the total budget for that purpose of $12.8 billion. Therefore, OPG stated that the success of its refurbishment of Unit 2 should be measured at the total envelope level.[224] OPG stated, in cross-examination by CCC, that if it completes Unit 2 at or below the total budget of $4.8 billion it expects that there will be no further prudence review of its Unit 2 spending.[225]

OEB Staff Submission

[221] Tr Vol 5 pages 35-36
[222] 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.
[223] Exh D2-2-8 page 8
[224] Exh D2-2-8 page 8
[225] Tr Vol 1 pages 114-115

OEB staff submits that the OEB should undertake a detailed prudence review, on a component-by-component basis, of all variances recorded in the CRVA regardless of the final cost of Unit 2 (and the campus plan projects). OEB staff is of the view that whether the overall variance in the CRVA is positive or negative does not change the requirement for the OEB to ensure that all incremental spending on each component of the DRP (for which there are in-service amounts approved for the test period) was prudent.

OEB staff agrees with OPG that from the perspective of OEB's shareholder if Unit 2 (and eventually the 4-unit DRP) were to come in on, or under, budget, the project as a whole would be considered successful. However, the OEB has a responsibility, in accordance with O. Reg. 53/05,[226] to confirm that all of the actual costs of the DRP were prudently incurred.

OEB staff is of the view that simply because one aspect of the DRP comes in under budget (which would provide an offsetting impact on the amounts recorded in the CRVA), that should not, on its own, mean that the OEB does not review overspending on other components of the refurbishment. This would be the outcome of OPG's proposed approach for the CRVA review.

OEB staff submits that ratepayers must be adequately protected from all spending in excess of the capital and non-capital costs that the OEB approves for inclusion in rate base and the revenue requirement over the test period. It would not be appropriate for ratepayers to cover the costs of potentially imprudent spending on one aspect of the DRP simply because there was under spending in another category. The actual costs incurred on each aspect of the DRP must be considered prudent on a standalone basis for it to be reasonably recoverable from ratepayers. Therefore, OEB staff submits that a detailed review of all incremental spending related to each component of the DRP must occur.

In order for a comprehensive review of variances in the CRVA to occur, the OEB requires a baseline to perform variance analysis that is at a sufficient level of granularity. If the OEB agrees with OEB staff's submission, the OEB should require OPG to provide as part of its Draft Payment Amounts Order a sufficiently detailed list of all of the components of the Unit 2 refurbishment and a list of all of the campus plan projects (> $5 million) for which there are in-service amounts approved as part of the current proceeding. The list should include the applied for and approved in-service

[226] O. Reg. 53/05, section 6(2)4

amount (based on the OEB's final determination in this proceeding) with the related applied for and approved contingency amounts shown separately.[227]

For reference, OEB staff has prepared the following tables to highlight the minimum level of detail that should be provided in the Draft Payment Amounts Order. OEB staff has attempted to compile the appropriate level of detail into a single table for the Unit 2 refurbishment and a single table for the campus plan projects.

For the components of the capital costs for the Unit 2 refurbishment, the table should, at a minimum, include the following details:

[227] If the OEB accepts OEB staff's proposal to reduce the contingency amount by $144 million. OPG should reflect the assignment of those contingency reductions on a category-by-category basis on a best efforts basis.

Table 13
Unit 2 Refurbishment Capital Costs

Project / Category ($million)	Applied for In-service Amount (net of contingency) (a)	Approved In-service Amount (net of contingency) (b)	Applied for Contingency (c)	Approved Contingency (d)
Retube & Feeder Replacement[228]				
Turbine Generator[229]				
Fuel Handling / Defueling[230]				
Steam Generator[231]				
Balance of Plant[232]				
Subtotal Bundles				
Program Execution				
Contract Management				
Engineering				
Managed System Oversight				
Planning & Controls				
Nuclear Safety				
Program Fees & Other Support				
Supply Chain				
Work Control				
Operations & Maintenance				
Subtotal Functions				
Early Release 3				
Early Release 4				
Subtotal Early Release Funds				
Program Contingency (not applied directly to any specific component)				
Total	4,106.1		694.1	

For the capital costs associated with the early in-service projects, F&I projects, and SIO projects for which there are in-service amounts proposed as part of the current proceeding, the table should, at a minimum, include the following details:

228 The Retube & Feeder Replacement Bundle should be further expanded to include the more detailed information provided in Chart 5 (Exh D2-2-8).
229 The Turbine Generator Bundle should be further expanded to include the more detailed information provided in Chart 6 (Exh D2-2-8).
230 The Fuel Handling / Defueling Bundle should be further expanded to include the more detailed information provided in Chart 7 (Exh D2-2-8).
231 The Steam Generator Bundle should be further expanded to include the more detailed information provided in Chart 8 (Exh D2-2-8).
232 The Balance of Plant Bundle should be further expanded to include the more detailed information provided in Chart 9 (Exh D2-2-8).

Table 14
F&I and SIO Capital Costs

Project ($million)	Applied for In-service Amount (net of contingency) (a)	Approved In-service Amount (net of contingency) (b)	Applied for Contingency (c)	Approved Contingency (d)
R&FR Tooling for Removal Activities				
Water and Sewer Project				
Darlington Energy Complex				
Retube Feeder Replacement Island Support Annex				
Refurbishment Project Office				
Electrical Power Distribution System				
Third Emergency Power Generator				
Containment Filtered Venting System				
Subtotal – Projects >$20 million				
IFB Heat Exchange Plate Replacement				
Negative Pressure Containment				
Heavy Water Islanding Modifications				
Low Pressure Service Water				
GM Facility Interim Office Leasehold Improvements				
Vehicle Screening Facility				
Powerhouse Steam Venting System Improvements				
Shield Tank Overpressure Protection				
Emergency Service Water Buried Services				
Subtotal – Projects $5 million - $20 million				
Subtotal - Projects <$5 million				
Total[233]	331.2		46.0[234]	

[233] The totals cited here reflect the removal of the in-service amount (including contingency) of the D2O project.

As part of the Draft Payment Amounts Order, OPG should also be required to show the applied for and approved in-service amounts associated with the labour costs for the Project Management and Oversight functions separately.

For the non-capital spending on the DRP during the test period, a similar level of detail as provided at Exh F2-7-1 is appropriate.

The OEB should use the information that OEB staff proposed that OPG file as part of the Draft Payment Amounts Order as a baseline for the variance analysis that would be completed at the time that the CRVA is brought forward for disposition. In order to ensure a consistent basis for the variance analysis no further reclassifications in the DRP-related budget should occur.[235]

OEB staff submits that the evidence filed with respect to the request for CRVA disposition should include detailed explanations for any cost variances that arise on all aspects of the DRP for which there are in-service amounts that are approved as part of the current proceeding. The evidence should also provide reasonably detailed explanations of key management decisions that were made throughout the course of the execution phase which led to cost variances on an actual basis.[236] In addition, the evidence should provide detailed explanations for all actual contingency spending (including rationale for the utilization of contingency amounts).

The OEB can review any cost variances against both the applied-for and approved in-service amounts, along with the detailed explanations for cost variances discussed above, to best determine the prudence of any overspending. While the debits in the CRVA will be calculated based on the difference between the actual in-service amounts and the OEB-approved in-service amounts, comparing the actual in-service amounts to the applied-for in-service amounts will be useful to provide additional context (particularly if the OEB agrees with OEB staff's proposals to approve in-service amounts that are lower than the amounts requested by OPG).

[234] This reflects the entire planned contingency budget for the F&IP and SIO projects across the entire DRP. Some of this contingency may not be part of the in-service amounts requested in the current proceeding. This would impact the split between the in-service amounts set out in column (a) and column (c).

[235] Exh L-4.3-Staff-71 page 3. OPG stated that as the DRP scope has been set in the RQE, it does not anticipate any further reclassifications of the DRP (i.e. no aspects of the Unit 2 refurbishment or campus plan projects will be moved outside of the DRP budget).

[236] The evidence with respect to management decisions should be augmented by the annual reports to the OEB discussed in OEB staff's submission at section 4.3.12.

OEB staff also submits that a similar issue that was raised by OPG with respect to the potential double recovery of capital costs on the hydroelectric side of the business[237] could occur on the nuclear side of the business. Therefore, OEB staff submits that a similar treatment as OPG proposed to apply to the hydroelectric capital costs should be applied to the nuclear capital costs in the CRVA.

With respect to the treatment of the hydroelectric capital costs in the CRVA, OPG provided supplementary evidence at Exh H1-1-2. OPG explained that there was the potential for the double recovery of costs as between the sustaining capital costs and the CRVA-eligible costs. OPG stated:

> However, while O. Reg. 53/05 requires that OPG recover prudently incurred costs associated with CRVA-eligible projects, it does not permit OPG to recover those costs once in base payment amounts and again through disposition of deferral and variance accounts. In that context, OPG acknowledges that it would only be appropriate for it to recover any balance in the CRVA if it can demonstrate that the costs of the projects recorded in the account have not been funded through base payment amounts during the 2017-2021 period.
>
> Therefore, in OPG's submission, it would only be necessary for the OEB to allow recovery of CRVA balances if OPG's total prudent capital spending in the 2017 to 2021 period (i.e., CRVA eligible and Sustaining Capital projects combined) exceeds the total amount of such capital spending implicitly funded through base payment amounts.[238]

OEB staff recognizes that OPG proposed the above treatment in the context of the ratemaking approach applicable to its regulated hydroelectric operations (incentive ratemaking on the basis of a price cap-index).[239] When asked about the applicability of the proposed treatment to the nuclear capital in-service amounts by CCC, OPG stated:

> I think we just need to really think about whether that's consistent with the regulation otherwise it's sort of appropriate in the context of the nuclear setup, in particular with the DRP in mind.[240]

OEB staff does not see why the same issue (i.e., double recovery of costs over the test period) that the proposed hydroelectric approach is designed to prevent could not potentially occur in relation to the nuclear capital portfolio (i.e., CRVA-eligible nuclear capital and nuclear operations and support services capital).

[237] Exh H1-1-2
[238] Exh H1-1-2 page 4
[239] Exh H1-1-2 page 4
[240] Tr Vol 20 page 85

In regard to the nuclear operations capital projects, OPG proposed annual in-service amounts during the 2017-2021 period associated with its nuclear operations (discussed at section 4.1.3 of this submission).[241] On that basis, OPG will recover, through its payment amounts, the revenue requirement associated with capital additions beginning in the year that the capital is forecast to be placed in service. If, for example, a capital project is delayed or the actual costs are lower than forecast, OPG would still recover the revenue requirement of those assets based on the forecast. There is no true-up (or variance account treatment) of the revenue requirement associated with the nuclear operations capital in-service amounts during the test period. The true-up would occur at the time of the next rebasing, whereby only capital actually placed in-service would be reflected in opening rate base.

In regard to the CRVA-eligible nuclear capital projects (which is almost entirely the DRP-related capital), once again OPG has proposed annual in-service amounts during the 2017-2021 period. Similarly, OPG will recover, through its payment amounts, the revenue requirement associated with each of those capital additions beginning in the year that the asset is forecast to be placed in service. However, for the CRVA-eligible nuclear capital projects, there is a true-up of revenue requirement associated with these in-service amounts during the test period (through the CRVA). Therefore, if, for example, a project costs more than originally forecast, the revenue requirement associated with that incremental capital would be recoverable through the CRVA (if the spending is deemed prudent by the OEB). At the time of rebasing, the DRP-related capital actually placed in-service would be reflected in the opening rate base (and the CRVA treatment would no longer apply to those assets).

The difference in treatment between the nuclear operations in-service amounts and the CRVA-eligible in-service amounts, as discussed above, allows for the potential notional double recovery of revenue requirement over the test period.

As an illustrative example, if OPG, on an actual basis, places less nuclear operations capital in service during the test period than approved and places more CRVA-eligible capital in service than approved, OPG will notionally recover the revenue requirement associated with incremental spending twice.[242] First, OPG would recover revenue requirement related to the nuclear operations assets that were not actually placed in service (or placed in service at a lower value than forecast).[243] Second, OPG would

[241] Exh D2-1-3 Table 4
[242] Assuming that the OEB eventually deems the incremental CRVA-eligible capital as prudent and approves the recovery of the incremental capital through the CRVA.
[243] Conceptually, this is revenue requirement that is not associated with any actual in-service capital costs and could notionally be used to fund the incremental in-service amounts for the CRVA-eligible capital.

recover the revenue requirement of the incremental CRVA-eligible capital through the disposition of the CRVA. OEB staff submits that this is not a reasonable outcome.

The OEB should require OPG to apply a similar treatment to the nuclear capital side of the CRVA as it has proposed to apply to the hydroelectric capital aspect of the account. This will ensure that a double recovery of revenue requirement across its nuclear operations capital and CRVA-eligible nuclear capital does not occur.

OEB staff submits that OPG should be required to file, in its Draft Payment Amounts Order, the aggregate revenue requirement associated with its approved nuclear operations and nuclear support services[244] in-service amounts for the test period (2017-2021). If at the end of the test period, on an actual basis, less revenue requirement than approved (on an aggregate basis) was required to support the in-service additions, the variance in revenue requirement should be used to offset nuclear capital related debits recorded in the CRVA.[245]

OEB staff submits that its proposed treatment of the nuclear capital aspect of the CRVA is consistent with section 6(2)4 of O. Reg. 53/05, which requires the OEB to ensure OPG recovers its DRP costs, as long as they are prudent. During the test period, the costs (or revenue requirement) of the incremental DRP in-service amounts would notionally be recovered through revenue requirement that is not needed to support nuclear operations capital (as that capital was not placed in-service). Going forward, at rebasing, the actual incremental prudently incurred DRP capital costs would be recovered directly as those costs would be included in rate base. Therefore, all prudently incurred costs associated with the DRP would be recovered by OPG.

Finally, OEB staff notes that there was some discussion at the oral hearing regarding the relationship between the disposition of the CRVA and rate smoothing.[246] OEB staff submits that this issue is best addressed at the time that the CRVA is brought forward for review. The OEB will have the opportunity, at that time, to consider both the appropriate disposition period of the CRVA and the impact of the disposition on any rate smoothing proposal that may be provided by OPG.

4.3.10 Refund of Earnings in Excess of the OEB-Approved ROE to Ratepayers

Background

[244] Limited to the nuclear portion that is directly assigned to nuclear rate base.
[245] The amount available for disposition should also be net of any earnings in excess of the OEB-approved ROE as discussed in section 4.3.10.
[246] Tr Vol 20 pages 90-92

OEB staff asked questions at the oral hearing regarding the potential for OPG to earn returns in excess of the OEB-approved ROE during the test period and at the same time incur costs associated with DRP that are greater than forecast.[247]

OPG confirmed that it is possible for OPG to earn an ROE greater than OEB-approved and overspend on the DRP relative to budget. For this to occur, it would require OPG to over earn in other areas of its business and for the cost overruns related to the DRP be deemed prudent as part of the CRVA review (and therefore the revenue requirement associated with these assets be deemed recoverable during the test period).

OPG further stated that it has never over-earned relative to its OEB-approved ROE in the past.[248]

OEB Staff Submission

OEB staff submits that it is not appropriate for OPG to earn an ROE in excess of the OEB-approved return and at the same time be allowed to recover the revenue requirement associated with overspending on DRP.

OEB staff recognizes that this scenario (i.e., overspending on the DRP and earning an ROE greater than OEB approved) is extremely unlikely to occur. However, if it did, it would mean ratepayers would have paid amounts to OPG that were used to: (a) cover the revenue requirement associated with DRP-related cost overruns; and (b) provide OPG a return in excess of the OEB-approved amount. Ratepayers should not be burdened with the cost of paying the revenue requirement associated with DRP-related cost overruns (even if they are prudently incurred) and also paying amounts that allow OPG to earn an ROE in excess of OEB-approved.

For the above reasons, in the scenario that cost overruns are incurred associated with the DRP and there are also overearnings, OEB staff submits that all amounts earned in excess of the OEB-approved ROE during the test period should be used to provide a refund to ratepayers to offset the revenue requirement associated with DRP-related cost overruns.

If the OEB accepts OEB staff's proposal, OPG should be required to identify any overearnings accrued during the test period. If the OEB eventually approves the

[247] Tr Vol 21 pages 107-110
[248] Tr Vol 21 page 109

recovery of revenue requirement related to DRP cost overruns through the CRVA review, any over earnings should be used to offset the nuclear CRVA debit amounts approved by the OEB prior to recovering the balance from ratepayers.

4.3.11 DRP OM&A

Issue 6.4 (Oral Hearing) – Is the test period Operations, Maintenance and Administration budget for the Darlington Refurbishment Program appropriate?

Background

OPG requested OEB approval of the following OM&A expenditures related to the DRP during the test period:[249]

Table 15
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

The proposed DRP-related OM&A expenditures over the test period are largely related to removal costs associated with the replacement of existing assets and Low and Intermediate Level Waste (L&ILW) variable expenses related to disposal costs (based on the volume of waste).[250]

The 2020 and 2021 DRP-related OM&A expenses include removal costs associated with the Retube and Feeder Replacements for Unit 3 (2020) and Units 1 and 3 (2021).[251]

OEB Staff Submission

OEB staff submits that the forecast DRP-related OM&A budget for the 2017-2021 period is reasonable.

OEB staff also notes that the actual DRP-related OM&A expenditures will be subject to CRVA treatment. With respect to the OM&A spending on the removal costs associated with the refurbishment of Units 1 and 3, OEB staff submits that this spending should be

[249] Exh F2-7-1 Table 1
[250] Exh F2-7-1 pages 1-2
[251] Exh F2-7-1 pages 2-3

considered, at the time of the CRVA review, in the context of the information that OPG had at the time that they begin the removal work. If there are significant uncertainties, prior to the start of the removal work, that the DRP will not continue past Unit 2 and OPG does move forward with the removal work, the OEB should consider whether the execution of that removal work was prudent.

4.3.12 DRP Reporting

Issue 10.4 (Oral Hearing) – Is the proposed reporting for the Darlington Refurbishment Program appropriate?

Background

OPG proposed to file annual reports with the OEB with respect to the DRP. [252] The expectation is that these annual reports will be placed on the public record in the normal course.[253] The measures that it plans to include in its annual report to the OEB are set out in the following table.[254]

Table 16
Proposed DRP Reporting

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

OPG also proposed to provide direct public reporting with respect to the DRP. OPG stated that it will issue frequent (monthly) updates on the status of the project on OPG's website. OPG also stated that it will provide more detailed public reporting on quarterly basis on the status of the DRP and will specifically provide information on Unit 2 safety, quality, cost performance and schedule performance.[255] The cost performance and

[252] Exh D2-2-9 page 9
[253] Tr Vol 2 page 131
[254] Exh D2-2-9 pages 9-10
[255] Undertaking JT1.18

schedule performance that OPG intends to provide on a quarterly basis to the public is qualitative in nature and does not follow specific cost performance index or schedule performance index formulas. OPG stated that the reporting is designed in a manner that is transparent and understandable by the general public.[256]

OPG also noted that it reports directly to its shareholder on a regular basis. There is a shareholder representative assigned to the Darlington Refurbishment Committee (DRC) who reports directly to the shareholder and has access to all of the same information that is available to all other members of the DRC.[257] In addition, OPG meets with its shareholder on a monthly basis to discuss the progress of the project and answer questions.[258]

OEB Staff Submission

OEB staff submits that the frequency of the proposed reporting is sufficient. OEB staff is of the view that annual reporting to the OEB along with more frequent reporting to the public is reasonable.

The reports filed with the OEB will be useful from the perspective of evaluating the prudence of DRP-related expenditures at the time the CRVA is reviewed but will not be used to determine whether the program should continue on a go-forward basis. Therefore, annual reporting is sufficient for those purposes.

It is OPG's shareholder that has the authority to make determinations regarding off-ramps related to the DRP and to decide whether refurbishment beyond Unit 2 should occur. Therefore, OEB staff submits that it is OPG's formal and informal reporting to its shareholder that must happen on a frequent basis (which OPG has stated will occur).

OEB staff submits that the format of the report to the OEB should generally be in accordance with the progress report template that was filed by Schiff Hardin in Undertaking J7.1. OEB staff is of the view that the level of detail proposed in that undertaking is appropriate for an annual report to the OEB (which will also be made available to the public). The reporting requirements set out in Undertaking J7.1 are generally aligned with the measures that OPG proposed as part of its application.[259] However, it includes a few additional reporting requirements (e.g., staffing levels, risk management, etc.).

[256] Tr Vol 2 pages 158-160
[257] Tr Vol 2 page 95
[258] Tr Vol 2 page 166
[259] Exh D2-2-9 pages 9-10

It also provides additional direction regarding the appropriate level of detail for the discussion that should be included as part of the annual report. For example, the undertaking states that “the reporting should be based on OPG memorializing not just the facts as they occur, but the steps of the process the management team and corporate leadership are using to make project management decisions for all significant technical, cost, schedule, safety, quality or other challenges to the DRP.”[260] OEB staff submits that the type of narrative set out above would be useful at the time that the balance in the CRVA is brought forward for review by the OEB as it would provide a historical perspective regarding OEB’s management of the DRP. This type of information would be of assistance for a prudence review.

5. NUCLEAR PRODUCTION FORECAST

5.1 Background

Issue 5.1 (Primary) - Is the proposed nuclear production forecast appropriate?

OPG’s proposed test period (2017-2021) production forecast is presented in the table below.

Table 17

Nuclear Production Forecast (TWh)						
	2017	2018	2019	2020	2021	Total (2017-2021)
Pickering (TWh)	19.1	19.2	19.4	19.6	18.8	96.1
Darlington (TWh)	19.0	19.3	19.7	17.7	16.6	92.3
Total Production (TWh)	38.1	38.5	39.1	37.3	35.4	188.4

The total nuclear production forecast for the period 2017 to 2021 is 188.4 TWh.

OPG states that its approach to developing the test-year production forecast is unchanged from its approach in EB-2013-0321 (the previous payments proceeding). In support of its forecast, OPG states that it continues to pursue initiatives focused on improving planned outage execution, equipment reliability and forced loss performance.

OPG’s nuclear generators are base load generators. OPG prepares separate production forecasts for each generating unit within the two nuclear stations. The total station production forecast is the sum of the unit forecasts and the total production forecast is the sum of the station forecasts.

[260] Undertaking J7.1 page 2

The production forecast is equal to the sum of the nuclear units' generation capacity multiplied by the number of hours in the year, less the number of hours for planned outages plus an estimate of forced production losses (unplanned outages and unplanned derates) and corrections for generation losses (lake temperature differentials, grid losses and station consumption). Based on factors including prior experience, the extent of planned outages and the impacts of unforeseen events, forced loss rates (FLR) that result in lost production opportunities are estimated and calibrated.

The notable factors affecting the test period production forecast as noted by OPG are:

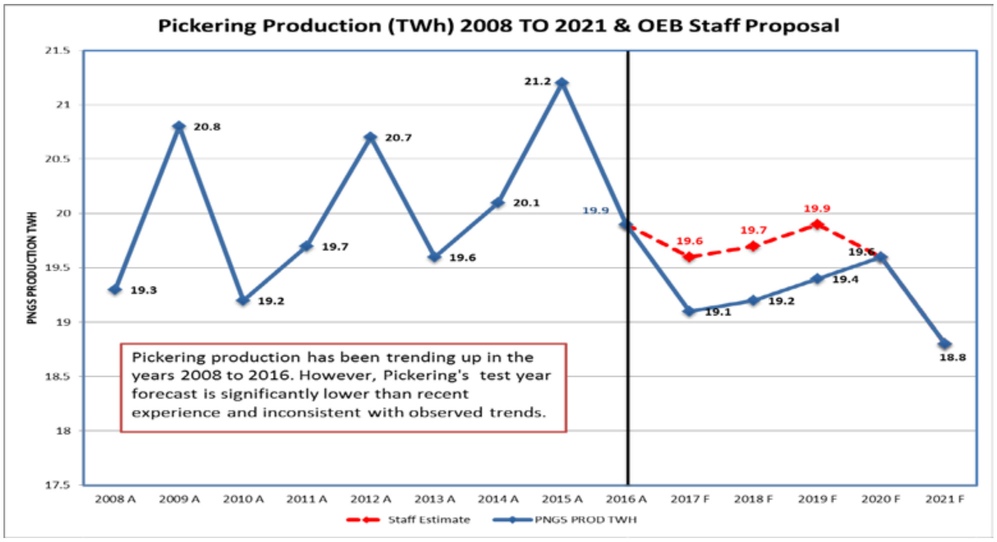
- Lost production due to the DRP where Unit 2 is planned to be out of service in 2016, followed by Unit 3 in 2020, Unit 1 in 2021 (and unit 4 in 2023). Each unit refurbishment project is planned to take more than three years to complete
- Two post-refurbishment mini-outages of 55 days and 31 days respectively, planned for Unit 2
- Eight mini-outages of approximately 20 days at Darlington to replace Primary Heat Transport pump motors
- Maintaining a stable Pickering FLR of 5%
- 637 incremental planned outage days in 2016-2020 to enable the completion of various work activities required for Pickering Extended Operations. These additional planned outage days reduce generation by 7.5 TWh over the period 2016-2020
- Continuation of mid-cycle planned outages on Pickering Units 1 and 4
- Maintaining a three-year outage cycle for Darlington and a two-year outage cycle for Pickering

5.2 OEB Staff Submission

In OEB staff's assessment, OPG's test period production forecast for Pickering is low and should be increased such that it is more in line with observed trends. For the reasons noted below, OEB staff submits that the OEB should increase Pickering's production forecast by 0.5 TWh per year for the first three years of the test period (i.e., 2017-2019).

Pickering Production Forecast is Low

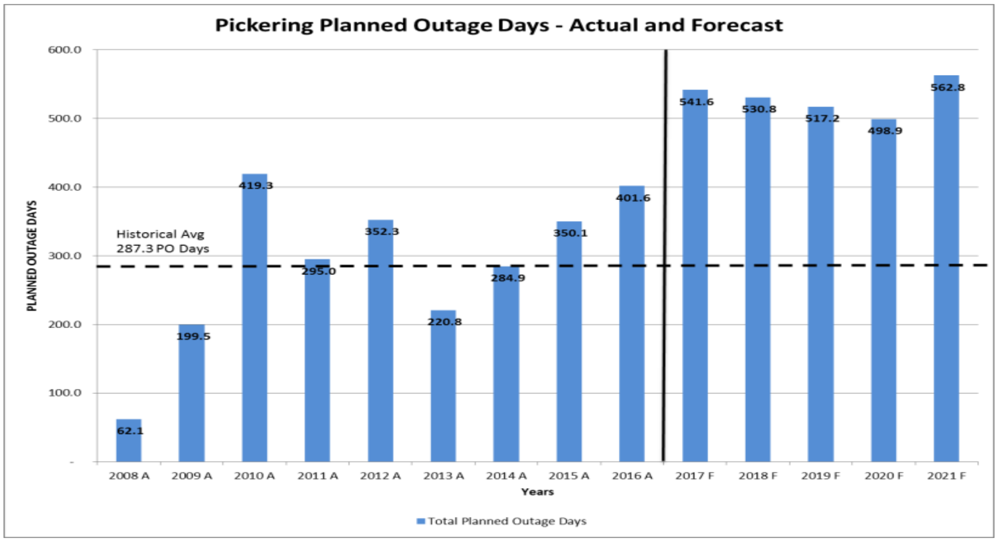
The graph below provides actual Pickering production from 2008 to 2016 and OPG's test period forecast for 2017 to 2021. The graph also plots OEB staff's proposed estimate for 2017 to 2021.



OEB staff notes that OPG's forecast of Pickering production in the test period is significantly lower than recent actual trends. As observed in the above graph, while Pickering production in the years 2008-2016 has fluctuated, it has trended upwards. By comparison the test period production is projected to decline sharply. For example, the 2017 production forecast of 19.1 TWh represents a 10% (or 2.1 TWh) decline in production from the highs of 2015. In staff`s view, such a large swing in production is not consistent with observed trends and has not been adequately explained.

OEB staff also observes that the projected decline in Pickering production is inconsistent with OPG's evidence of the initiatives it has undertaken to improve reliability at Pickering. For example, OPG states that Pickering performance has been improving, as evidenced in the 2015 Pickering FLR of 2.9% (compared to a 2010-2014 average FLR of 9.6%). OPG also states that over the past four years it has undertaken aggressive maintenance programs to reduce Pickering maintenance backlogs and instituted better planning and execution of outages. In staff's view, the noted improvements are reflected in the production increases witnessed over the 2008 to 2016 period. In contrast the test period production forecast is markedly lower than actual historical experience suggesting that the test period production forecast has not taken into consideration any of the noted improvements.

Pickering Planned Outage Days Forecast is High



One of the drivers for the decrease in test year production at Pickering is the number of Planned Outage Days (PO Days). OEB staff is concerned that the test period estimate for PO Days is excessive, inconsistent with historical experience and has not been sufficiently justified.

OPG's production forecast is underpinned by a PO Days schedule of 542 days in 2017, 531 days in 2018, 517 days in 2019, 499 days in 2020 and 563 days in 2021. OPG's test period PO Days estimate includes 637 incremental PO Days (2017-2020) to do PEO related work. The resultant production losses arising from PEO related work equals approximately 7.5 TWh over the five year period.

Table 18

Pickering Planned Outage Days (PO DAYS) Last 5 Years (Actual) vs Test Year (Forecast)				
	TOTAL PLANNED OUTAGE DAYS 2012-2016 (ACTUAL DAYS)	**TOTAL PLANNED OUTAGE DAYS 2017-2021 (FORECAST DAYS)**	**DIFF (DAYS)**	**DIFF %**
PNGS U1	234.7	569.9	335.20	143%
PNGS U4	231.1	424.6	193.50	84%
PNGS U5	193.7	506.0	312.30	161%
PNGS U6	216.8	455.7	238.90	110%
PNGS U7	335.8	326.0	- 9.80	-3%
PNGS U8	339.1	369.1	30.00	9%
TOTAL (PO DAYS)	**1,551.2**	**2,651.3**	**1,100.10**	**71%**
PEO PO DAYS		637		
EXCL. PEO PO DAYS	1,551.2	2,014.30	**463.10**	**30%**

OEB staff submits that OPG's total test period forecast of PO Days is extremely high compared to historical experience. For example, as seen in the above table, in the 2017-2021 period, OPG is forecasting a total of 2,651.3 PO Days. By comparison, in the most recent five year period (2012-2016), OPG's actual PO Days were 1,551.2. That is a 71% increase compared to the last five years. After adjusting for PEO related PO Days, the test period PO days forecast represents a 30% increase compared to the last five years. In fact the 30% difference is understated because OEB staff`s analysis did not adjust the historical period to remove PO days related to the Pickering Continued Operations project.

OEB staff also notes that in the period 2012-2016, OPG undertook various initiatives to improve Pickering reliability and performance. The result of this work was that OPG processed over 3,000 pending work orders and made targeted improvements to components and systems. OPG states that it has caught up with its maintenance schedule and outstanding maintenance work orders are at a historic low. Further, Pickering FLR has improved from an average 9.6% (2010-2014) to an all-time-low FLR of 2.9% in 2015. Given the improvements in Pickering maintenance OEB staff questions the continued need for the significant increase in test period PO Days.

Increase in Planned Outage Days Forecast is not Justified

The accuracy of OPG nuclear production forecast has been a matter of concern for OPG and the OEB. This was noted in the EB-2013-0321 proceeding. As part of the 2014-2016 Business Plan, OPG's production forecasting group was directed by OPG senior management to improve production forecast accuracy because of a concern that OPG was consistently over-forecasting (i.e. OPG's forecast was consistently higher than actual production).

At the oral hearing OPG confirmed that it had not undertaken a comprehensive assessment of its forecasting methodology and nor had it engaged an external expert to review its methodology.[261] OPG however noted that in the 2014-2016 period it had made significant improvements in outage planning and execution and that these improvements will improve production forecast performance.

Upon reviewing OPG's Planned Outage Day forecasting record[262] for Pickering for 2008-2016, OEB staff observes that on average, OPG's forecasts have been 8.9% above actuals. Focusing on the 2014-2016 period (the period in which OPG has made

[261] Tr Vol 12 page 125
[262] Undertaking J12.8

improvements to outage planning and performance), OPG's forecast of PO days was higher than actual experience by 13.1% in 2014 and 8% in 2016, although in 2015 the forecast was 3.2% too low. The analysis is shown in the table below.

Table 19

Pickering Planned Outage Day Forecast Accuracy					
	Forecast PO Days	Actual PO Days	Error	Error %	Notes
Forecast Accuracy (2008-2016)	2,774	2,527	247	8.9%	Forecast Higher than Actual by 8.9%
Forecast Accuracy (2014)	328	285	43	13.1%	Forecast Higher than Actual by 13.1%
Forecast Accuracy (2015)	339	350	- 11	-3.2%	Forecast Lower than Actual by 3.2%
Forecast Accuracy (2016)	402	369	32	8.0%	Forecast Higher than Actual by 8.0%

Given this record of over-forecasting coupled with the absence of a comprehensive review of OPG's production forecasting methodology, OEB staff is concerned that OPG's PO days forecast may be over-stated and that the significant increase in PO Days that are proposed in the test period has not been adequately justified.

Lessons Learned/Mid-Cycle Outages

In its evidence OPG has often cited that it incorporates "lessons learned", i.e., experience from previous, similar outages and maintenance activities, to inform its estimates for future planned outages which in turn have a direct impact on the nuclear production forecast.

At Exh E2-1-1, page 6 OPG introduces the concept of "lessons learned".

> Planned outages are complex, involving many OPG divisions and individuals working together. Outages require focus, expertise, high levels of coordination and a level of detail that exceeds that of major construction projects (due to regulatory complexity and constraints in work execution). **The planned outage schedule also incorporates "lessons learned" from recent OPG outages and operating experience outside of OPG.**
> [Emphasis Added]

OPG claims that it "learns" from previous experience and this results in increased operating efficiency, reduced outage durations and lower costs.

To the extent that future planned outages are comprised of similar activities and procedures as previous outages, then it stands to reason that future outage durations should be shorter than previous outages. In its filed evidence, OPG supports the conclusion that most planned outages are comprised of routine or repetitive maintenance – prime candidates for applying “lessons learned” from previous procedures.

At Exh E21-1, page 7, OPG states:

> The majority of work in an outage typically is routine preventive maintenance and inspection activities, while the remaining work is non-routine breakdown maintenance and modification.

In response to interrogatory Exh L-5.1-CCC-24 OPG provides a summary of planned outages for the 2017-2021 test period for the Pickering and Darlington generating stations with specific durations and impacts on revenue and energy production for each specific planned outage.

This table lists “mid-cycle” outages for Pickering Units 1 (2018, 2020) and 4 (2017, 2019) over the 2017-2020 period. Each of these outages is estimated to last 43 days resulting in a 0.5 TWh energy production reduction and revenue impacts ranging from $35 million to $48 million. OEB staff presumes that labelling these outages generically as “mid-cycle” is indicative that similar maintenance and procedures will be performed during each of these scheduled outages. Therefore, these scheduled outages would be particularly suited to a “lessons learned” approach for outage planning.

In OEB staff’s view, OPG’s estimates of a generic duration of 43 days for each mid-cycle outage and reductions of 0.5 TWh in energy production do not reflect a lessons learned approach to outage planning.

While OEB staff is not recommending any changes to the Darlington production forecast, similar concerns exist for the planned outages to replace PHT pump motors. There are four PHT pump motors per Darlington unit, 16 motors in total. Over the 2017-2021 test period, OPG has scheduled four outages for Unit 4 (2017, 2018, 2020, 2021), two outages for Unit 1 (2018, 2019) and one outage for Unit 3 (2017). Each of these outages is forecast to be for 20 days with 0.4 TWh of energy production lost and $28 million to $43 million of reduced revenue.

OPG testified in cross-examination that the PHT pump motor replacement in 2015 required an outage of 28 days[263] and that a reduction to 20 days was sufficient proof ofa lessons learned approach in the current production forecast. OEB staff is unconvinced that the 2015 experience is similar to a routine, scheduled maintenance procedure and submits that it is more indicative of an anomalous unplanned outage. Therefore, the

[263] Tr Vol 12 page 148

2015 PHT pump motor outage offers no guidance of whether a 20 day outage reflects the limit for marginal efficiency increases in pump motor replacement procedures.

In summary, OEB staff submits that OPG's production forecast for Pickering should be increased by 0.5 TWh for each of the years 2017 to 2019. The as-filed total forecast for Pickering for 2017-2021 is 96.1 TWh. OEB staff's proposed adjustment would increase the 2017-2021 forecast to 97.6 TWh (a 1.6% increase over three years).

6. OPERATING COSTS

6.1 Nuclear OM&A

Issue 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?

The historical and forecast nuclear OM&A are summarized in the following table. The Exh N1-1-1 impact statement increased test period OM&A by $252 million related to higher payments for pension deficit funding as a result in a decrease in discount rates, and by a further $41 million for the implementation of the CNSC Fitness for Duty requirements.

OPG's Custom IR application proposes a stretch factor on base OM&A and allocated corporate OM&A (lines 1 and 7 in the table below). OEB staff's submission on corporate costs is found in section 6.8.

Table 20
Nuclear OM&A

	$million	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2016 Actual	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
1	Base	1,127.7	1,127.1	1,159.6	1,201.8	1,182.4	1,210.6	1,226.0	1,248.4	1,264.7	1,276.3
2	Project	105.7	101.9	115.2	98.2	89.3	113.7	109.1	100.1	100.2	86.6
3	Outage	277.5	221.3	313.7	321.2	306.7	394.6	393.8	415.3	394.4	308.5
4	SubTotal Operations	1,510.9	1,450.3	1,588.5	1,621.2	1,578.4	1,718.9	1,728.9	1,763.8	1,759.3	1,671.4
5	Darlington Refurbishment	6.3	6.3	1.6	1.3	3.1	41.5	13.8	3.5	48.4	19.7
6	Darlington New Nuclear	25.6	1.5	1.3	1.2	0.6	1.2	1.2	1.2	1.3	1.3
7	Corporate Costs	428.3	416.2	418.8	442.3	426.2	448.9	437.2	442.7	445.0	454.1
8	Centrally Held Costs	409.9	416.9	461.0	331.9	329.3	80.2	118.2	108.3	91.1	81.3
9	Asset Service Fee	22.7	23.3	32.9	28.4	34.1	27.9	27.9	28.3	22.9	20.7
10	SubTotal Other	892.8	864.2	915.6	805.1	793.3	599.7	598.3	584.0	608.7	577.1
11	**Total OM&A**	**2,403.7**	**2,314.5**	**2,504.1**	**2,426.3**	**2,371.7**	**2,318.6**	**2,327.2**	**2,347.8**	**2,368.0**	**2,248.5**
	Exh N1-1-1						**2,346.0**	**2,351.4**	**2,425.1**	**2,469.0**	**2,349.1**

Source: Exh F2-1-1 Table 1, Undertaking J14.2 Attachment 1

6.1.1 Base OM&A

Base OM&A is the largest category of OM&A. As noted in the application, "Base OM&A provides the main source of funding for operating and maintaining the nuclear stations".[264] The test period proposal is a 1.24% average annual increase in base OM&A, which OPG characterizes as "modest" given labour and material cost escalation. The major cost groupings within base OM&A are summarized in the table below.

Table 21
Nuclear Base OM&A

	$million	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2016 Actual	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
1	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
2	Overtime	48.6	46.7	54.5	47.8	63.7	46.4	46.5	46.1	47.4	47.8
3	Augmented Staff	3.1	3.6	4.4	3.3	6.7	4.5	3.5	3.0	2.6	1.6
4	Materials	85.1	73.4	83.4	70.5	81.7	68.4	68.2	68.5	71.1	70.8
5	License	34.2	32.6	34.5	36.4	36.0	37.2	38.7	39.6	40.2	40.6
6	Other Purchased Services	100.0	98.7	108.4	164.1	129.1	161.1	185.1	180.8	178.3	187.3
7	Other	24.3	44.9	40.3	35.0	58.0	34.2	37.0	36.2	40.2	40.3
8	Total	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
9	Labour and Overtime (lines 1,2)	881.00	873.80	888.50	892.50	870.90	905.40	893.40	920.40	932.40	935.70
	Base OM&A Table from Exh F2-2-1 Table 2 and J14.3 Attachment 1										

In cross examination, OEB staff questioned whether the proposed increase in base OM&A was appropriate as the DRP will result in fewer units to operate during the test period. There will also be fewer outages – which require some base OM&A resources. Similar to responses to interrogatories,[265] OPG stated that the majority of its costs are fixed. OEB staff queried base OM&A overtime in cross-examination,[266] again pointing to fewer units in service. OPG replied that it applied a percentage to labour expense to determine the proposed overtime expense.

Undertaking J14.3 was filed after the OEB staff cross-examination. The proposed 2017 labour cost is $52 million higher than 2016 actual, or $34.5 million higher if labour is considered with overtime (line 9 of the above table). While some base OM&A labour costs may be fixed, OEB staff submits that the level of those costs should not be as high as OPG has proposed for the test period as one to two Darlington units will be undergoing refurbishment. The evidence at Exh F2-2-1 page 3 states that base OM&A overtime is, "The incremental pay for work outside of core hours, for example forced outages or urgent repairs." With one to two Darlington units in refurbishment mode for

[264] Exh F2-2-1 page 1
[265] Exh L-6-1-AMPCO-92
[266] Tr Vol 13 page 87

the entire test period, OEB staff submits that overtime should be lower than proposed. OEB staff submits that the labour and overtime should be reduced by half of the variance between 2016 actual and 2017 proposed, or $15 million for each year of the test period.

There is another impact of the DRP on base OM&A. During DRP (Panel 1B) cross-examination, OPG stated:

> … if we were to find ourselves in a critical need of a resource, we're also able to move people around in our nuclear fleet and assign people to the project.[267]

During cross-examination on nuclear OM&A, OPG stated:

> The one thing that we do see occurring is we swing -- we call it swinging. We transfer 100 people over to the DRP project, so they are no longer in our Darlington operating costs. So we do transfer them to do work on DRP and do sort of the operations work and maintenance work that's under that realm.[268]

And in response to cross-examination on the potential for double counting of base OM&A and DRP capital in relation to these swing staff, OPG replied:

> The DRP project was costed based on requirements, what needed to get done, what kind of work needed to get done. And through business planning, we ensured we were not double counting those numbers. And based on the scope of work DRP needed, we knew they would be those kinds of people and they would move over, and what was remaining was in Darlington operations.
>
> So we ensured, and I know because I was vice-president of nuclear finance at the time, and we worked with our finance folks. We actually did a diligence process around ensuring that there was no double counting.[269]

It is OEB staff's understanding that the swing staff were not identified in the application filed on May 27, 2016. OEB staff submits that the response to cross-examination of Panel 1B indicates some fluidity to the movement of staff. This creates uncertainty with respect to the proposed OM&A. OEB staff submits that the testimony supports OEB staff's view that some of the proposed test period base OM&A work is discretionary and that the expense proposed is too high. OEB staff submits that OPG should provide a description of the diligence process referred to by the OPG witness, and the supporting documentation and cost reconciliation in future proceedings. The OEB staff submission on nuclear business FTEs is in section 6.3.

[267] Tr Vol 3 page 31
[268] Tr Vol 13 page 77
[269] Tr Vol 13 page 80

After labour, the next largest grouping within base OM&A is Other Purchased Services. The pre-filed evidence states that, "In order to operate the nuclear facilities safely, reliably and efficiently, OPG uses incremental short-term labour resources to address temporary staffing shortages. Incremental labour resources used by OPG include overtime, temporary staff (e.g., non-regular staff) and external contractors."[270] During cross-examination, OEB staff questioned whether there was an inverse correlation between nuclear operations FTEs and purchased services. OPG replied that labour agreements generally do not allow it to use purchased services to do work that would ordinarily be conducted by unionized employees, but due to an inability to get resources on a timely basis, purchased services have been hired.[271] OEB staff noted that there was a significant variance between 2014 and 2015 forecast base OM&A other purchased services, and actual. The OPG witness was not able to provide specific reasons for the variance, but suggested that some work was not done.[272]

OEB staff has reviewed the historical plan and actual base OM&A other purchased services, and the 2010 to 2016 data are summarized in the following table. There is a consistent underspend, and the average underspend over the seven years is $24.4 million. OPG's proposed base OM&A other purchased services expense for the test period ranges between $161 million and $187 million.

Table 22
Base OM&A Other Purchased Services

$million	2010	2011	2012	2013	2014	2015	2016	Total
Plan	109.7	102.1	99.6	126.7	145.9	146.4	164.1	894.5
Actual	97.0	94.8	95.4	100.0	98.7	108.4	129.1	723.4
Variance	-12.7	-7.3	-4.2	-26.7	-47.2	-38.0	-35.0	-171.1
Source: Exh F2-2-1 Table 2, EB-2010-0008, EB-2013-0321, EB-2016-0152								

OEB staff submits that base OM&A other purchased services should be reduced by $25 million for each year of the test period. The total base OM&A reduction proposed by OEB staff related to test period over forecasting and other purchased services is $40 million for each year of the test period.

6.1.2 Outage OM&A

[270] Exh F2-2-1 page 8
[271] Tr Vol 13 page 91
[272] Tr Vol 13 page 92

In steady state operation, Darlington units are scheduled for outages every three years and Pickering units every two years.

The application states that, "Work activities are planned at a detailed level, and resource requirements are identified using material requirements and resource productivity information from recently-completed outages."[273] The application also states that, "Similar outage activities (e.g., unit shut down and start up windows) are benchmarked to ensure that the benefits of process improvements and efficiencies are incorporated."[274]

In response to cross-examination by OEB staff, OPG stated that the cost of a Darlington unit outage was in the range of $80 to 100 million.[275]

OEB staff notes that outage OM&A (not including outage OM&A related to Pickering Extended Operations) is one of the major drivers of deficiency in the test period.[276] OEB staff cross-examined OPG about the outage OM&A expense and work planned for the test period. OPG explained that there are "outage costs associated with the refurbishment unit that is spread out over three years."[277] OPG further explained, "So we are spending outage OM&A on those particular units, and basically it's the work that would be done in a regular outage, but we don't have to take an outage for it. We can do all of the work during the refurbishment period."[278]

The following table summarizes outage OM&A for the historical and test period for units 1 and 2. Unit 2 was taken out of service in October 2016 for refurbishment and is planned to return to service in 2020. The refurbishment of Unit 1 is planned to start in 2021.

Table 23
Outage OM&A – Darlington Units 1 and 2

$million	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Unit 1	2.2	70.1	1.7	8.3	122.6	1.1	6.4	128.2	6.1
Unit 2	83.9	0.5	0.1	16	53.7	38.7	31.7	17.8	13.6
Source: L-6.1-VECC-20									

273 Exh F2-4-1 page 3
274 Exh F2-4-1 page 6
275 Tr Vol 13 page 67, page 69
276 Exh A1-3-4 page 6
277 Tr Vol 13 page 67
278 Tr Vol 13 page 68

The proposed 2017 to 2019 outage OM&A expense for Unit 2 is $124.1 million. This budget is higher than the $80 to $100 million for a typical unit outage. As the Unit 2 2017 to 2019 outage expense occurs during refurbishment, the expense would not include expense related to outage activities for shut down and start up. In addition, the Unit 2 outage would be limited to work on non-life limiting components (as life-limiting components are already being worked on separately through the DRP). The application states that there are many standard elements included in the outage scope, but that there can be unique activities. The only example OPG provided of a unique activity is the need for a single fuel channel replacement. This unique activity would not apply for Unit 2 regular outage OM&A as Retube and Feeder Replacement is a DRP major work bundle.

It is OEB staff's understanding that there may be outage OM&A work that is additional to a regular outage, and that can only be done during an extended outage, e.g. the refurbishment. Some examples of this work are listed in Exh L-6.1-Staff-96. In cross-examination, OPG staff were unable to categorize the work as safety related or CNSC related.[279]

OEB staff notes that a regular outage is scheduled for Unit 1 in 2020, prior to the planned DRP outage in 2021. OEB staff also notes that the forecast outage OM&A for Unit 1 in 2021 is $6.1 million. OEB staff submits that this level of expense is likely appropriate for the extended outage work. OEB staff submits that the 2017 to 2019 outage OM&A expense for Unit 2 is too high for a limited (i.e., limited by DRP) regular outage and extended outage work.

OEB staff's submission on outage OM&A costs related to Pickering are at section 6.5.

OEB staff has reviewed the historical plan and actual outage OM&A expense, and the 2010 to 2016 data are summarized in the following table. There is under-spending in five of the seven years. The average underspend is 5%.

[279] Tr Vol 13 page 65

Table 24
Nuclear Outage OM&A – Plan and Actual

$million	2010	2011	2012	2013	2014	2015	2016	Total
Plan	284.6	214.8	201.1	311.0	262.7	330.7	321.2	1926.1
Actual	278.2	215.0	214.3	277.5	221.3	313.7	306.7	1826.7
Variance	-6.4	0.2	13.2	-33.5	-41.4	-17.0	-14.5	-99.4

OEB staff submits that on the basis of historical underspending and uncertainty regarding scope of outage OM&A work on units undergoing refurbishment, a 5% reduction in outage OM&A for each year of the test period is appropriate.

6.2 Nuclear Operations Benchmarking

Issue 6.2 (Oral Hearing) - Is the nuclear benchmarking methodology reasonable? Are the benchmarking results and targets flowing from OPG's nuclear benchmarking reasonable?

6.2.1 Background

Benchmarking has been an important tool for the OEB for many years. The Renewed Regulatory Framework, upon which OPG based many elements of its application, specifically speaks to the usefulness of benchmarking.[280]

The OEB has also historically relied on benchmarking to assist it in setting payment amounts in each of OPG's cost of service applications. OPG's Memorandum of Agreement (MOA) with its shareholder includes a requirement that it benchmark, and present its benchmarking results to the OEB as part of its payment amounts applications. The MOA dated August 17, 2005, stated: "OPG will seek continuous improvement … improve the operation of its existing fleet." The MOA was amended July 17, 2015, however, and the current version states simply: "OPG shall undertake periodic benchmarking appropriate for its operations and type of assets, including as part of its submissions to the OEB." It is not clear exactly what changes, if any, the amendments to the MOA are meant to signify to OPG. However, OPG has confirmed that it continues to seek continuous improvement in its nuclear operations. It also remains committed to rigorous benchmarking.[281]

[280] *Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, pages 59-60.
[281] Tr Vol 13, pages 3-4.

OPG filed limited benchmarking information prepared by Navigant in its first payments application (EB-2007-0905). The OEB was dissatisfied with the amount of benchmarking that had been done, and directed OPG to file more thorough information with its next application. As a result of this, OPG retained ScottMadden Inc. to prepare two reports: a phase 1 report which benchmarked OPG's performance relative to a peer group, and a phase 2 report which included ScottMadden's observations and recommendations for improvement. Both of these reports were completed in 2009 and reviewed OPG's 2008 nuclear performance.

The Phase 2 Report included targets that ScottMadden believed OPG would be able to achieve by 2014, and that would "achieve, or significantly drive the company closer to, top quartile industry performance."[282] OPG agreed to these targets and included these targets, and in three instances more aggressive targets, in its 2010-2014 business plan.[283]

Although ScottMadden benchmarked OPG against its comparators on 19 metrics,[284] it identified three of these as "key metrics". These are: total generating cost (TGC), which is "all-in" cost for producing 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.[285] OPG has further adopted TGC as its enterprise wide measure of operational cost effectiveness.[286]

OPG has continued to use the ScottMadden benchmarking methods, and has produced results annually since 2008.

6.2.2 Benchmarking Results

OEB staff produced a summary which shows the high-level results of the ScottMadden benchmarking analysis from 2008-2015, as well as forecasts for 2016-2017.[287] The annual results presented in rows A through K are three year rolling averages. The summary was reviewed with OPG's witnesses in the hearing and is reproduced below (note that for NPI and UCF a higher number is "better", whereas for TGC a lower number is better):

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[282] EB-2010-0008, Exh F5-1-2 page 1
[283] Undertaking J13.1
[284] OPG now benchmarks on 20 metrics
[285] Tr Vol. 13, pages 8-10
[286] Ibid., page 10
[287] Exh K12.4, page 18. As noted on the table, all of the data is taken from the application.

Summary of Nuclear Benchmarking Reports

	---Rolling Actual Results---								--Annual--				
	a	b	c	d	e	f	g	h	i	j	k	l	m
Darlington	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
WANO NPI (Index)	95.67	95.10	94.10	92.80	96.30	90.80	92.10	83.70	87.30	84.30	85.50	83.10	98.60
2-Year Unit Capability Factor (%)	91.99	90.20	89.40	89.60	92.00	90.44	89.41	83.96	91.10	85.10	90.00	85.10	93.30
3-Year Total Generating Costs ($/New MWh)	30.08	32.77	33.55	33.05	31.67	34.42	37.73	44.38	47.35	47.85	46.47	49.75	36.75
Pickering													
WANO NPI (Index)	60.90	67.17	64.30	66.10	64.70	67.50	64.30	68.50	72.30	71.10	75.60	69.70	77.83
2-Year Unit Capability Factor (%)	67.65	74.47	74.57	72.50	75.62	75.77	74.50	77.32	77.60	71.50	75.30	71.50	82.10
3-Year Total Generating Costs ($/New MWh)	67.05	66.42	65.62	65.86	67.16	67.18	67.93	67.36	71.09	76.48	72.46	78.83	66.84
Pickering A													
WANO NPI (Index)	60.84	61.10	47.70										70.90
2-Year Unit Capability Factor (%)	56.60	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
Q2
Q3
Q4

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

As filed with Applications

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

Overall, OPG has performed very poorly with respect to the three key metrics. Its overall rankings for NPI, UCF and TGC have been close to last or last in 2008, 2011, 2014 and 2015.

When broken down by station level, Pickering is shown to be an especially poor performer. For the last three years for which we have actuals (2013-2015), Pickering has been fourth quartile for all three of the key metrics, and in fact has never performed higher than third quartile in any of the key metrics.

As OPG explained in the hearing, there are many challenges to operating Pickering in a cost effective and efficient manner (at least as compared to the peer group). Two of the most important factors are the relatively small unit size (the Pickering units are only 515 MW) and the "first generation" CANDU technology.[288]

Darlington has generally performed much better. Its performance in the three key metrics up to 2014 was first or second quartile. However, in 2015 performance slipped and Darlington was second quartile for TGC, third quartile for NPI, and fourth quartile for UCF. OPG attributes this to two factors: a vacuum building outage (VBO) scheduled for 2015 (which results in both lower production and increased costs), and forced losses that were caused by problems with PHT pump motors.[289]

Although OEB staff recognizes that it is useful to assess and set targets for the two stations individually, ultimately it is OPG's overall benchmarking results that are most relevant. The OEB is setting payment amounts for the nuclear business as a whole, and that is what ratepayers will be paying for.

OEB staff also recognizes that Pickering is an older facility and that it is not realistic to expect that it will be a top performer. That does not mean, however, that OPG should not be seeking to continually improve its performance. This is especially true given OPG's intention to continue operating the facility in spite of its poor performance.

OEB staff is also troubled by the recent downturn in Darlington's performance. OPG justifies this downturn by pointing to the VBO and some problems with PHT pump motors. While OEB staff does not doubt these statements, it is OEB staff's view this is not a satisfactory answer. OPG has had VBOs in the past (most recently in 2009), and this did not result in a significant change in Darlington's performance against the key metrics. It must also be noted that all nuclear facilities will have periodic outages for one

[288] Tr Vol. 13 pages 13 and 32
[289] Tr Vol 13 pages 24-26

reason or another over the course of their service lives. Although most of OPG's comparators would not have VBOs (as it is specific to CANDU technology), they would have outages for other reasons that would impact their performance in the key metrics. For example, most of OPG's benchmarking comparators have to go off-line to refuel, whereas OPG does not.[290]

Similarly, problems with the PHT pump motors are under OPG's control, and doubtless its comparators from time to time are faced with similar challenges. Under any benchmarking exercise there will be numerous differences between the individual participants in the study. They operate in different jurisdictions, may have different local labour conditions, may use somewhat different technologies, and will be operating plants of various vintages. Overall, however, they are broadly similar and are expected to be broadly comparable – indeed that is why they were selected as comparators by OPG's expert consultant ScottMadden. OPG, the provincial government (i.e., the shareholder), and the OEB all agree that benchmarking is important and should inform the OEB's payment setting process.

Overall, OPG's benchmarking performance does not demonstrate continuous improvement, and in fact it appears to be trending in the opposite direction. OPG's benchmarking results for 2015 are amongst the worst they have been since benchmarking began in 2008: overall they were second last on all three key metrics, Pickering was fourth quartile for all three key metrics, and Darlington was second quartile (TGC), third quartile (NPI), and fourth quartile (UCF).

Even though the 2015 results are in fact derived using rolling averages[291], OEB staff understands that one data point (i.e. the 2015 results) do not necessarily constitute a trend. However, the forecast results for 2016 and 2017 show little if any improvement. OPG provided forecast figures for 2016-2017 with its original application (columns I and J), and then updated forecasts with its N1 update (columns K and L). It is notable that for all three key metrics the numbers in the N1 update are either the same or worse than the original forecast. The 2017 N1 forecast is also not materially different from the 2015 results: for Darlington NPI and UCF are about the same while TGC is worse, and for Pickering NPI is slightly better and UCF and TGC are worse.

It should also be observed that the Darlington results are presented on what OPG describes as a "normalized" basis. The purpose of normalizing is to account for the fact

[290] Tr Vol 13 page 26
[291] Typically 3 year rolling averages; UCF is based on 2 year rolling average for Pickering and 3 year rolling average for Darlington

that between one and two of Darlington's four reactors will be out of service during the test period and beyond. Production will therefore fall significantly, though many of the fixed costs associated with the station will not. Absent some type of normalization, this would significantly impact several of the benchmarked metrics, in particular TGC.

The calculation of TGC is straightforward: total costs (i.e., the numerator) is divided by total production (i.e., the denominator). To normalize its results, OPG simply inflated the denominator (production) to the level it would have been at had one or two of the units not been out of service.[292]

Although ScottMadden is OPG's nuclear benchmarking consultant, and it established OPG's entire benchmarking framework and methodology, curiously OPG did not consult with ScottMadden to assist it in deciding how to normalize (or even to decide if normalizing is appropriate at all). OPG did later seek ScottMadden's input, though this was after OPG had settled on the normalization methodology and filed the results with its application.[293]

ScottMadden completed its normalization report (the Normalization Report) in February 2017. In a carefully qualified opinion, the Normalization Report concluded that OPG's approach was "unique but logical, reasonable and easy to understand."[294] However, ScottMadden also highlighted several problems with OPG's approach.[295] Ultimately it appears to have determined that OPG's approach was not the preferred approach to normalization: "ScottMadden's evaluation found that, while refurb is a unique megaproject, a more strongly supported and conventional approach to normalization of cost metrics under comparable scenarios was to adjust the distribution of actual costs to reflect performance of the operating units while using actual MWhs generated in the denominator."[296]

The approach used by OPG, therefore, does not appear to be the approach that would have been recommended by its expert consultant, had that consultant been asked in advance. This calls into question OPG's use of normalization, and the extent to which this approach is appropriate for its setting of targets and forecasts over the test period.

[292] Tr Vol 13 pages 37-38
[293] Undertaking J13.2. OPG asked ScottMadden to look at the issue in August 2016, and ScottMadden filed a report in February 2017
[294] Exh L-6.2-Staff-101, Attachment 1, page 7
[295] Exh L-6.2-Staff-101, Attachment 1 pages 6-7
[296] Exh L-6.2-Staff-101, Attachment 1 page 7

Even accepting OPG's approach to normalization, however, OPG's recent and forecast benchmarking performance does not represent continuous improvement. In fact the trend seems to be in the opposite direction. The 2015 results, as discussed above, were the worst that Darlington has achieved since benchmarking began in 2008. The results forecast for 2017 are generally worse than historic results.[297] The operational targets in OPG's current Business Plan include TGC targets for both Pickering and Darlington. Both show steady increases through to 2019. From 2016 (target) to 2019, Pickering's TGC is expected to increase from $71.09 to $81.49, whereas for Darlington the increase is from $47.35 to $52.33.[298] Note that the Darlington forecast is the "normalized" number; the actual TGC number is more than $10 higher.[299]

OPG has also failed to meet the 2014 key metrics targets that it set for Pickering and Darlington with the assistance of ScottMadden. These targets were set in 2009 as part of ScottMadden's initial work with OPG. Both OPG and ScottMadden felt they were achievable, and they were included in OPG's 2010-2014 Business Plan. Although they were described in the oral hearing as "stretch targets",[300] they appear in the Business Plan as simply the targets OPG felt it could achieve. The analysis of this issue is slightly complicated by the fact that OPG reports its results on a rolling average basis, whereas the targets were set for a single year only – OPG's reported results for 2014 reflect the average of 2013, 2014 and 2015 results (although UCF is based on 2 year rolling average for Pickering and 3 year rolling average for Darlington).

On a quartile basis, OPG met only two of the six individual targets, and one of the targets that was "achieved" was a fourth quartile result for Pickering TGC (i.e. the lowest result possible). On an absolute basis (i.e., the absolute number as opposed to the quartile placement) OPG failed to hit all six targets.[301]

6.2.3 Benchmarking Conclusion

OPG's overall benchmarking results are poor.

In some areas, such as UCF and NPI for Pickering, there has been modest improvement on an absolute "numbers" basis. However, OPG's comparators have improved in those areas as well. On a quartile basis – which actually compares OPG's

[297] Exh K12.4, page 18, column L
[298] Exh N1-1-1 Attachment 1, page 24
[299] Exh F2-1-1 page 17. OPG's pre-filed application shows the non-normalized 2019 forecast for Darlington as $64.61. This number, however, was not updated with the N1 update and may have changed somewhat.
[300] Tr Vol 13, page 6
[301] Exh K12.4, page 18, columns G and M

performance against comparable nuclear operators – OPG has shown no improvement since benchmarking began in 2008. In fact progress appears to have stalled and may even be regressing. As the OEB noted in the EB-2013-0321 decision, "this is not the type of performance that ratepayers would expect".[302]

Poor benchmarking results - particularly in the TGC category, which is an overall measure of cost effectiveness - have a direct impact on payment amounts. On the most recent information available, OPG as a whole ranks 12th out of 13 on TGC, and has never been higher than 10th out of 13. This persistent poor performance has cost ratepayers many millions of dollars over many years.

It is difficult to measure the exact dollar cost of poor performance. It is also probably not reasonable to expect OPG to achieve first or second quartile overall results, given the first generation technology and small unit size at Pickering. However, these costs are real and ratepayers should not bear the burden of OPG's persistent inability to improve its benchmarking results overall. The poor benchmarking results support OEB staff's recommendations for the nuclear Custom IR stretch factor and for disallowances under other categories, including compensation and OM&A.

6.3 Nuclear Staffing Benchmarking

6.3.1 Background

In response to OEB direction from the EB-2010-0008 decision, OPG filed an examination of nuclear staffing levels in EB-2013-0321. Goodnight Consulting Inc. conducted a nuclear staffing study in July 2011 indicating that OPG nuclear staffing was 17% above the comparable benchmark (report filed with OPG February 3, 2012). The results were subsequently updated/aged in February 2013 and indicated that the gap had dropped to 8% above the benchmark (report filed with OPG May 10, 2013). In the current proceeding, OPG has filed the Goodnight analysis of March 2014 data (report filed with OPG December 22, 2014).

From 2011 to 2015, OPG implemented the Business Transformation initiative to improve its cost structure and to design a more efficient and effective organization. This initiative led to the creation of a centre-led organizational structure, reduced the regular OPG headcount by 2,700 and introduced changes to eliminate work, improve processes and achieve efficiencies.

[302] EB-2013-0321, Decision with Reasons, pages 45-46

OEB staff has summarized nuclear FTEs, base OM&A purchased services, and a graph of the results for the three Goodnight benchmarking studies on page 92. The impact of the Business Transformation Initiative headcount reduction is evident in the FTE numbers at lines 3, 5 and 9 and the graph of the Goodnight benchmarking. The impact of the Business Transformation centre-led organizational structure is evident in the FTE numbers in lines 1 and 4.

The Goodnight benchmarking is done on an adjusted basis so that activities specific to CANDU design were excluded, e.g., staff necessary for heavy water management, and for OPG's 35 hour work week vs. 40 hours for comparators. The comparisons also exclude major outage and project work like DRP. The summary at page 92 separates DRP FTEs from Operations and Corporate FTEs. The 2014 Goodnight benchmarking included 531 baseline contractors, of which 335.7 are not included in OPG's FTE reporting. OPG does not include contractors in its FTE analysis. Contractors are only included in purchase service costs. OEB staff has listed the cost of base OM&A purchased services at line 10 on page 92 as a proxy for the baseline contractors. Based on the OEB staff analysis, Goodnight benchmarked 62% of OPG's FTEs and proxy contractors.[303]

6.3.2 Exclusions

The initial 2011 Goodnight study excluded 2,101 OPG nuclear FTEs that could not be benchmarked to PWR/BWR industry peers. The 2014 Goodnight study excluded from benchmark 2,036 OPG nuclear FTEs. As noted above, the exclusions included CANDU specific exclusions and DRP staff. Goodnight's summary of the 2,036 FTEs excluded was provided at Exh F2-1-1 Attachment 2 page 14.

In cross-examination, OEB staff put to the OEG witnesses a comparison of the 2014 Goodnight benchmarking and OPG's actual 2014 FTEs.[304] The OEB staff analysis indicated that Goodnight's starting point, before exclusions, was lower than OEB's staff's determination of the starting point by 1,310 FTEs. OPG undertook to review the analysis, and responded that the summary of the exclusions at page 14 of the Goodnight report is incorrect.[305] OPG replied that the difference in FTEs is related to indirect corporate staff, non-regular staff not benchmarked, security staff and timing differences. It is not clear from the undertaking response whether Goodnight assisted

[303] Exh K12.4 page 46: Calculation 5421.1/8767.5
[304] Exh K12.4 page 46
[305] Undertaking J13.4

with the response. OEB staff submits that confirmation should be filed with OPG's reply submission.

6.3.3 Critical Staff

The application notes the high level of attrition in 2015 and the need to replace critical staff:[306]

> In 2015, Nuclear attrition was at its highest level in years, with over 300 retirements.[4] This represents a 20 per cent increase in the number of retirements in Nuclear compared to 2014. Over two thirds of the 2015 retirements were in critical operations, maintenance, engineering and technical roles and will need to be replaced.
>
> [4] These retirements include only those reporting to the Nuclear organization directly. Attrition associated with support staff attributed to the prescribed nuclear facilities is not reflected in this number.

In cross-examination of the Nuclear Operations witnesses (Panel 3B), OEB staff questioned whether the 200 critical positions (i.e. two thirds of 300) was indicated by the drop in regular operations staff at line 1 on page 92, from 5,626.7 FTEs in 2014 to 5,430.4. The OPG witness was uncertain, however, believed that most of the increase in FTEs vs, 2015 was related to rehiring of critical positions.[307]

6.3.4 Test Period FTEs

The Goodnight benchmarks are from steady state on-power activities.[308] In 2014, both Darlington and Pickering were at steady state operation, and OEB staff submits that the 2014 operations FTEs and purchased services were higher than benchmark, but approaching benchmark. Assuming steady state operation, OPG's proposed FTEs and purchased services are much higher than the 2014 levels in the 2016 bridge year and the first three years of the test period, 2017-2019. The proposed 2016-2019 operations FTEs do not demonstrate the sustainability of the Business Transformation Initiative.

As noted in the tables at page 92, the 2015 actual FTEs are lower than 2014 actual FTEs. OEB staff queried why the 2016 FTE proposal exceeded the 2015 levels after accounting for the hiring to replace 200 critical staff. In response, OPG indicated that actual 2016 FTEs were below plan,[309] and actual data was provided by undertaking.[310] The proposed and actual 2016 FTEs are summarized in the table at page 92.

[306] Exh F4-3-1 page 6-7
[307] Tr Vol 13 page 83
[308] Exh F2-1-1 Attachment 2 page 17
[309] Tr Vol 13 page 49, page 83

In 2014, the DRP was not in the execution phase. However, in the test period, there will be at least one Darlington unit undergoing refurbishment and two units in 2021. OEB staff submits that there is some uncertainty whether the benchmark (i.e., 2014 levels) can be extrapolated to the non-steady state test period. As noted in the base OM&A submission at section 6.1.1 and the outage OM&A submission at section 6.1.2, OEB staff submits that the expenses proposed in the test period are too high for non-steady state operation.

OEB staff notes that actual 2016 operations FTEs, 6,184.9, are similar to 2014 actuals, 6,204.8 FTEs. OEB staff submits that 6,200 FTEs is a reasonable level of nuclear operations staffing for steady state operation. As noted in the table at page 92, OPG's proposal for 2017-2019 exceeds 6,200. And as noted in the submission on base OM&A, OEB staff notes the added uncertainty with respect to swing staff for DRP.

OEB staff's submission on lower FTEs for nuclear operations is consistent with, and supports, the submission on OM&A. The disallowance that OEB staff is recommending on account of overstaffing is subsumed in its recommended disallowance under OM&A. The OEB staff submission on nuclear allocated corporate support is at section 6.8.

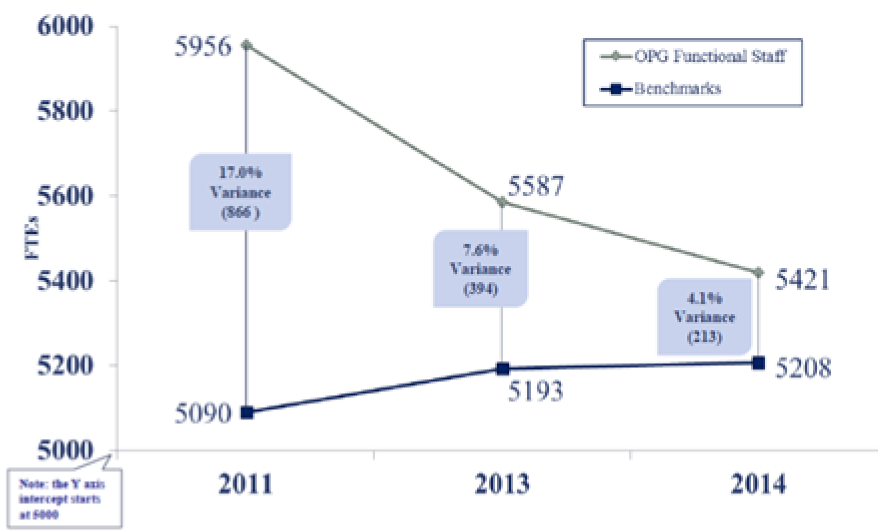
OEB staff cross-examined the nuclear OM&A and compensation witnesses on contractors and purchased services. OEB staff submits that OPG should examine the Goodnight methodology for determining contractor FTEs. The total purchased services and FTE equivalents should be filed in future proceedings.

[310] Undertakings J13.3 and J14.6

NUCLEAR FTEs

	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												
1	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
2	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
3	**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												
4	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
5	**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												
6	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
7	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
8	**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**
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**
10	Base OM&A Purch Serv ($M)	94.8	95.4	100.0	98.7	108.4	164.1	129.1	161.1	185.1	180.8	178.3	187.3

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



6.4 Nuclear Fuel

Issue 6.3 (Secondary) - Is the forecast of nuclear fuel costs appropriate?

In settlement, the parties agreed to a 2% downward adjustment to nuclear fuel bundle costs in each year. OEB staff accepts the expenses related to the other components of nuclear fuel cost, as set out in the application.

In section 5.2, OEB staff submits that the Pickering production forecast should be increased by 0.5 TWh per year for the period 2017-2019. This would result in an increase in the related nuclear fuel expense using a reference of $5.74 million/TWh for Pickering.[311]

6.5 Pickering Extended Operations

Issue 6.5 (Oral Hearing) - Are the test period expenditures related to extended operations for Pickering appropriate?

6.5.1 Background

Under OPG's current plan, all six units of the Pickering Nuclear Generating Station are planned to end operations in 2020. OPG is proposing to extend the operation of Pickering 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 (Pickering Extended Operations or PEO). OPG states that the plan to extend operations has been endorsed by the Minister of Energy and the Province of Ontario.[312]

In this application OPG is requesting approval for certain incremental costs that are needed to prepare Pickering for operations beyond 2020. In respect of year 2021, the first year of Pickering Extended Operations, OPG is requesting approval for the normal operating costs for Pickering, as it is requesting for each of the preceding test years. The table below provides a summary of the incremental costs that are sought for recovery in the test years.

[311] Exh L-11.5-VECC-50
[312] OPG's AIC page 89

Table 25

Pickering Extended Operations Incremental Costs Budget 2016-2021							
($ millions)	2016	2017	2018	2019	2020	2021	Total (2016-2021)
Enabling Costs	$ 15	$ 26	$ 55	$ 107	$ 104	$ -	$ 307
Restoration Costs	$ -	$ 15	$ 32	$ 56	$ 147	$ -	$ 250
Total	**$ 15**	**$ 41**	**$ 87**	**$ 163**	**$ 251**	**$ -**	**$ 557**
Source: Ex L-6.5-STAFF-116							

Enabling Costs: This category represents costs needed to complete the Periodic Safety Review, the Fuel Channel Life Assurance project, component condition assessments, maintenance programs and potential modifications required to demonstrate fitness for-service beyond 2020. Enabling Costs are forecast to be $307 million from 2016 to 2020.

Restoration of Normal Operating Costs (or Restoration Costs): This category represents costs to restore on-going operating and maintenance programs that were previously expected to cease as Pickering was planned to shut down in 2020. Restoration Costs are forecast to be $250 million from 2017 to 2020.

The first year of extended operations occurs in 2021. The 2021 operating costs are forecast to be $1,395 million[313] and are required to maintain ongoing base operations, project and outage OM&A work as well as projects necessary to continue the safe operation and maintenance of the plant. These costs also include funds for a scheduled Vacuum Building Outage in 2021.

6.5.2 Cost-Benefit Analysis

In support of the incremental test period expenditures OPG has provided the cost-benefit analysis that was prepared by the Independent Electricity System Operator (IESO) at the request of the Ministry of Energy.[314] As part of this analysis the IESO undertook an assessment of various Pickering life-extension scenarios. The IESO's analysis was prepared in March 2015 and was updated in October/November 2015.

At a high level this analysis compares the cost of operating Pickering from 2021 to 2024 against a comparable alternative, in this case, a single-cycle gas generator. Based on this comparison (and some additional benefits arising from certain deferments) the IESO estimates a net benefit on net present value basis of $300 million to $500 million in favour of the Ontario electricity system.

[313] AIC Chart 7.4, page 92
[314] Tr Vol 8 pages 39-42

The IESO's analysis was extensively examined in the proceeding. Parties have noted that if some of the assumptions in the IESO's analysis were updated with more current information, the result is that the project is uneconomic. The evidence is that the analysis is sensitive to natural gas prices and if current natural gas price forecasts are used, the net benefit is eliminated. Additionally, the analysis is also sensitive to Pickering production, where a 10% decline (6 TWh) in production could eliminate the net benefit. The analysis is also sensitive to Pickering operating costs, noting that a 15% increase in OPG's costs could eliminate the benefit. The IESO for its part has noted that an update to the analysis involves more than simply updating certain variables and requires a complete re-think of system planning considerations that underpin the analysis.

The IESO's assessment indicates that Pickering extension has merit for the following reasons:

- Defers timing of need and the supply/transmission investments that would otherwise be required
- Defers procurement decisions with respect to new resources, providing more time in exercising options while reducing risk of over investment during a period of supply/demand uncertainty
- Provides insurance supply in some years in case of nuclear refurbishment delays
- Defers Pickering decommissioning and severance costs
- Offsets production from natural gas-fired resources
- Increases export revenues and reduces carbon emissions

At the hearing, the IESO reiterated its support for the project, by highlighting the need and the benefits of PEO.[315]

6.5.3 Canadian Nuclear Safety Commission Licence Renewal

One of the major risks for the project is whether the Canadian Nuclear Safety Commission (CNSC) will grant OPG's request for renewal of Pickering's operating licence on the basis of the Periodic Safety Review and the technical analysis in relation to the Effective Full Power Hours (EFPH).

[315] Tr Vol 8 pages 87-99

The current five-year power reactor operating licence for Pickering is set to expire August 31, 2018. OPG will be applying for a 10-year licence, to cover the period of extended operations and safe shutdown following extended operations. As a separate matter, the CNSC has authorized operation of Pickering to 247,000 Equivalent Full Power Hours (EFPH), which in effect means that Pickering meets the technical capabilities to operate to 2020. On the basis of assessments that OPG has since undertaken, OPG has high confidence that it can operate the units to 261,000 EFPH, which in effect will allow Pickering to operate to 2022/2024. Therefore, the renewal of the operating licence to 2020 on the basis of EFPH does not appear to be a concern; however the matter of whether CNSC will grant approval for operation beyond 2020 is not certain. Furthermore, any conditions imposed by the CNSC, if extensive, could also render the project unfeasible. The CNSC's decision is expected no later than August 2018.

6.5.4 Long-Term Energy Plan

The Government of Ontario's 2013 Long-Term Energy Plan (LTEP) (i.e., the current LTEP) planned for Pickering operation to 2020 (with the possibility of early shutdown in 2018 pending completion of the Clarington Transformer). While the planning documents that are being used in the development of the new LTEP also assume Pickering operations beyond 2020,[316] it is not yet known whether the 2017 LTEP will endorse PEO. In this proceeding, OPG referred to a Government of Ontario media release that confirms the government's approval of OPG's plan to pursue PEO.[317]

6.5.5 OEB's Decision on Motion by Environmental Defence

In its decision on the motion by Environmental Defence (Motion Decision), the OEB made certain findings in respect of the scope of issue 6.5 and the role of the IESO's analysis in the OEB's review. The OEB determined that an update of the IESO's cost-benefit analysis was not required, the consideration of alternatives was a system planning function and out-of-scope and that "the scope of the OEB's review in issue 6.5 is to assess the appropriateness of the expenditures related to PEO".[318]

6.5.6 OEB Staff Submission

[316] AIC, page 90
[317] Exh L-6.5-Staff-115
[318] Decision and Order On Motion Filed By Environmental Defence, February 16, 2017, p. 4

OEB staff shares some of the concerns of the parties regarding the PEO cost-benefit analysis, and uncertainties related to licensing and the LTEP. Although the Motion Decision states that the full scope of the OEB's review of PEO will be determined in the final decision,[319] OEB staff understands from the Motion Decision that the issue of "need" for PEO is to be made by the system planner (i.e., the Minister through the LTEP), and not by the OEB. This is consistent with the *Electricity Act, 1998* which clearly identifies the Minister as the system planner, through the vehicle of the long term energy plan (LTEP).

As discussed above, Pickering operations beyond 2020 are not contemplated in the current LTEP. However, the discussion documents relating to the new LTEP (expected to be released sometime in 2017) show that PEO may be in the new LTEP, as the Minister has indicated support for the project.

On the understanding that the OEB is not considering the actual need for PEO (which is the role of the system planner), OEB staff recommend that the OEB be clear that it is not making any findings regarding the economic justification for PEO. As discussed above, the economic analysis conducted by the IESO is very sensitive to the assumptions that were used, and some of the key assumptions used are no longer valid. It is an open question as to whether the PEO would still show benefits if the model were re-run today.

More importantly, a "need" analysis is the role of the system planner. Even if the PEO were shown to be uneconomic, the legislative framework places the responsibility for the need analysis with the Minister, not the OEB.

To be clear, OEB staff is not asking for a finding that PEO is not economically justified. Absent an updated economic analysis it is not possible to make a determination either way. More importantly, that is the role of the system planner, and not the OEB.

OEB staff's submission will therefore focus on the incremental costs related to PEO – which comprise of the Enabling Costs and Restoration Costs described earlier.

Enabling Costs:

Despite the IESO's confirmation that Pickering is still an important part of the provincial supply mix, and OPG's confidence in the station's technical capabilities, OEB staff submits that there is a chance the PEO project will not proceed. The CNSC could deny

[319] Motion Decision, page 3

OPG's licence application or the new LTEP could find Pickering is no longer needed. In light of this uncertainty, OEB staff submits that the OEB should approve only the 2017 and 2018 expenditures, by which time the CNSC's decision and the new LTEP will be known. With respect to enabling expenditures planned in 2019 and 2020, these should be tracked in the CRVA, for disposition at a later date.

OEB staff notes that the enabling expenditures in the early years are primarily needed to complete the Periodic Safety Review (a CNSC requirement) and the Fuel Channel Life Assurance project (an aspect of the licence renewal application). By approving these costs the OEB would be allowing OPG to complete the licencing process. Therefore to balance the noted risks against the need for the expenditures, OEB staff submits that the OEB should approve only the 2017 and 2018 expenditures ($81 million), as opposed to the full $307 million. This will allow OPG to do the work necessary for the CNSC's licence process, while also allowing the System Planner to complete the planning that is ongoing in the development of the new LTEP. With respect to enabling costs in 2019 and 2020 and any costs incurred after that, the expenditures should be tracked in the CRVA for disposition at a later date.

Restoration Costs:

These are costs to prepare the Pickering units for operation beyond 2020 and are needed only if the project proceeds as planned. However, given the uncertainty with the project, OEB staff submits that the OEB disallow the Restoration Costs that are budgeted in the test years. Instead, OEB staff submits that the OEB should require OPG to track the Restoration Costs in a deferral account and that OPG consider commencing the Restoration work after it has received approval from the CNSC, which is expected in 2018. This will ensure that Restoration Costs are incurred only if the project is expected to proceed and not before.

Pickering Operating Costs in 2021

The first year of extended operations occurs in 2021. The 2021 Pickering operating costs are forecast to be $1,395 million. Elsewhere in this submission OEB staff has proposed reductions to the test period OM&A budget. It is submitted these reductions will ensure Pickering costs are reasonable in 2021 and set a reasonable base of costs for the remaining duration of the project.

In summary, OEB staff submits that the OEB should approve the Enabling Costs for 2017 and 2018 ($81 million). With respect to Enabling Costs in the 2019 and 2020 period, OEB staff submits that the costs should be recorded in the CRVA for disposition later date. With respect to the Restoration Costs, OEB staff submits that the OEB disallow the Restoration Costs at this time and require that these expenditures be tracked in a deferral account once the decision of the CNSC is known.

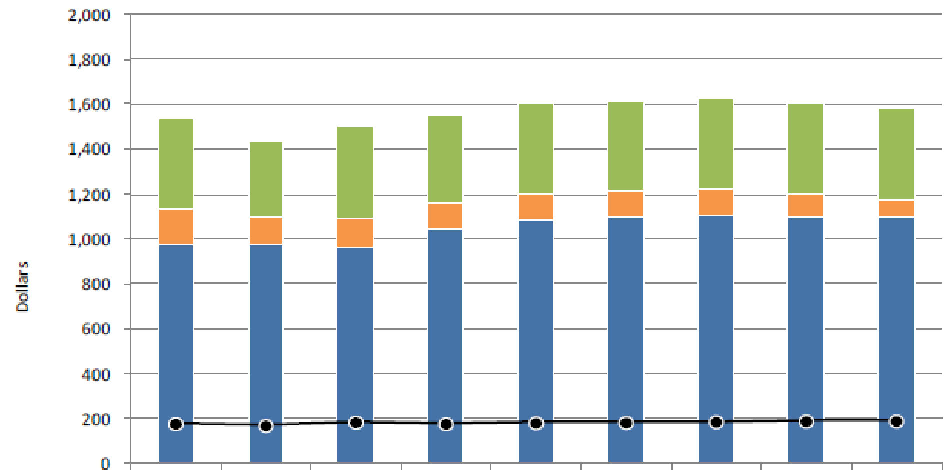
6.6 Compensation

Issue 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?

6.6.1 Background

OPG's total nuclear compensation costs (base salaries and incentives, overtime, and pensions and benefits) are a significant component of its total OM&A expenses, and indeed of its entire revenue requirement. Broadly speaking OPG's compensation costs are driven by two factors: the number of employees it has, and the amount it pays these employees (including pensions, benefits, overtime etc.)

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.

Total compensation costs during the test period range from a high of $1.623 billion (2019) to a low of $1.582 billion (2021), averaging approximately $1.605 billion per year. The trend in overall compensation costs is slightly down, whereas the total compensation per employee is slightly up.

Total compensation costs only include costs for direct employees, meaning those employees for whom OPG issues a T4 Statement of Remuneration.[320] OPG also refers to these staff as regular (full time and part time) and non-regular (e.g., students). Recently, OPG introduced “term employees”, hired with the understanding that they have no expectation of ongoing employment once Pickering operations cease. Term employees are considered non-regular staff. The FTEs listed in Exh F4-3-1 Figure 3 and in Exh F4-3-1 Attachment 1 are regular and non-regular staff.

[320] Tr Vol 17 pages 39-40

Total compensation costs do not include third party contractors. OPG obtains contractor services through augmented staff (external personnel providing specialized expertise) and other purchased services. There was lack of clarity regarding contractor services from non-regular staff in the previous and the current proceeding.[321] OPG clarified that contractor costs are not attributed to FTEs.[322]

6.6.2 Collective Bargaining

Approximately 90% of OPG's employees are unionized, either with the Society of Energy Professionals (the Society) or the Power Workers' Unions (PWU). OPG is legally required to negotiate employee compensation with its unions, the result of which is a collective agreement that sets out the terms of employment (including compensation) with the members of that union.[323] OPG's current collective agreements expire on March 31, 2018 (the PWU) and December 31, 2018 (the Society), by which time OPG will have to negotiate new collective agreements. Costs related to the existing collective agreements and forecast costs from the next collective agreements are included in the application.

The requirement to bargain collectively places limitations on OPG's ability to control its compensation costs. OPG cannot simply dictate terms to its unionized employees, and a failure to reach an agreement could result in a work stoppage (either through a strike or a lockout). Although the OEB should be cognizant of these limitations when setting the reasonable amount of recovery for compensation costs, the fact that OPG has a largely unionized workforce does not mean that compensation costs are an automatic "pass through". The OEB can (and has) assessed the reasonableness of these costs by using tools such as benchmarking. It should also be observed that although the collective agreements set wage rates for the individual employees, they do not speak to the number of employees OPG must have, nor to the amount of overtime that OPG will use (though the rates for overtime are set in the collective agreements).

6.6.3 Previous Decisions

OPG's compensation costs have been a contentious issue since the first payment amounts proceeding before the OEB. In that case the OEB disallowed $35 million in OM&A costs on account of poor performance at Pickering A. In the second cost of service proceeding (EB-2010-0008) the OEB disallowed $145 million over two years on

[321] Exh L-6.6-SEC-15
[322] Undertaking J16.7
[323] Tr Vol 16 page 44

account of excessive compensation. This decision was appealed by OPG, and was ultimately upheld by the Supreme Court in 2015.[324] In the most recent cost of service proceeding (EB-2013-0321) the OEB disallowed $200 million over two years largely because of excessive compensation costs.

6.6.4 Total Direct Compensation

OPG retained Willis Towers Watson (WTW) to conduct a benchmarking study on its compensation levels (i.e. employee remuneration). The WTW study of 2015 compensation is divided into two sections: total direct compensation, and pensions and benefits. OEB staff's submission will also review these two categories separately.

Total direct compensation (TDC), as defined and benchmarked by WTW, includes average salary, target bonus, and other applicable allowances.[325] It does not include overtime, nor does it include the lump-sum payment or share performance plan that were part of the most recent collective agreements (discussed in further detail below).[326] It also does not include benefits for existing employees, which is covered in the report under pensions and benefits. If compared to OPG's nuclear compensation chart (Figure 3, shown on page 100 of this submission), total direct compensation would include most of, but not all of, the third line – "base salaries & incentives".[327] Further, WTW benchmarked regular employees only. [328]

The WTW study shows that OPG has made some improvement with respect to the competitiveness of its total direct compensation when compared to the evidence filed in previous proceedings. Overall the WTW study shows OPG's TDC to be "at market" (i.e., +/- 10% of target) for the positions surveyed.

However, there are some important caveats to this conclusion. As observed above, the WTW study excludes several material components of compensation: most importantly overtime, the lump sum payment, and the share performance plan.[329] Overtime costs for the nuclear business average approximately $107 million per year over the test period.[330] OEB staff accepts that many or all of the comparator organizations will also have some level of overtime costs; however the WTW study does not benchmark this.

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[324] 3 S.C.R. 147
[325] Exh F4-3-1 Attachment 2 page 8
[326] Tr Vol 16 pages 52-53
[327] Tr Vol 16 pages 53-54
[328] Tr Vol 16 page 50
[329] Tr Vol 16 page 52
[330] Exh F4-3-1 Attachment 1

Perhaps more concerning is the exclusion of the lump sum payment and the share performance plan. These are direct incentives that will be paid out to most OPG employees during the test period. The total cost of these incentives is $92 million over the test period.[331] It is unlikely that OPG's comparators have similar incentives that have been excluded from their total direct compensation. While OEB staff understands that these incentives were the *quid pro quo* for some concessions that were obtained with respect to pension funding, they are still part of employee compensation, and as discussed further below pensions and benefits costs remain well above market. It is OEB staff's view that excluding these incentives tends to understate OPG's total direct compensation.

The overall WTW report results for total direct compensation were as follows: 8% above target market for the PWU positions surveyed, 8% above the target market for the Society positions surveyed, and 13% below market for the management group positions surveyed. Overall the result was 5% above market for all the positions surveyed. As WTW considers a result that falls within +/- 10% to be at market, OPG overall is at market.[332] Although it is not known what OPG's benchmarking results would have been had the share performance plan and lump sum payments been included, given how close the PWU and SEP were to the +10% threshold, it seems very possible that inclusion of these incentives would have pushed them into the "above market" category.

In spite of these overall results, OPG remains significantly above market in certain areas. This issue is most pronounced regarding the "general industry" group. General industry includes roles that may require formal education, but do not require in-depth knowledge specific to energy generation.[333] The general industry group for both the Society and the PWU are significantly above market for total direct compensation at 27% above for both.[334] Clearly there are areas where OPG is compensating its employees much more than industry norms.

This issue may be exacerbated by the fact that WTW appears to have had difficulty in finding appropriate "matches" for many general industry positions. Although WTW was able to benchmark 81% of PWU positions overall, it was only able to benchmark 69% of PWU general industry positions. It was similarly able to benchmark 74% of all Society positions, but only 51% of Society general industry positions. This suggests that general

[331] Exh L-6.1-Staff-147, page 3
[332] Exh F4-3-1 Attachment 2 page 11
[333] Exh F4-3-1 Attachment 2, page 5
[334] Exh F4-3-1 Attachment 2 page 11. OPG overall is 19% above market for general industry.

industry positions have less relative weight in the survey than utility positions and (for the PWU) nuclear authorized positions.[335]

OPG has also chosen, with WTW's support, to consider the 75th percentile to be "at market" for the nuclear authorized segment. The WTW report states that this is to reflect the "role complexity" of the nuclear authorized positions.[336] OPG further observed that its personnel faced additional challenges because Darlington has four operating units and Pickering has six operating units, whereas most of the comparators have only two operating units. OPG further stated in its testimony that CANDU technology could also be a driver for higher compensation for its nuclear authorized group.[337]

OEB staff submits that these arguments are not convincing and that the appropriate benchmark is the 50th percentile for all groups, including nuclear authorized. The comparator positions in the nuclear authorized group are all from nuclear generating stations – that is the very reason they were selected as appropriate comparators. As in any benchmarking study there will be a number of differences between the comparator organizations. However, the arguments in favour of using the 75th percentile as the point of comparison are not convincing. It is not obvious why having four units instead of two would automatically make a job more complex, and therefore deserving of significantly higher compensation.

The impact of paying TDC above the 50th percentile has been estimated by OPG to be $29.6 million.[338] SEC's analysis, which includes extrapolation of benchmarked incumbents to all incumbents, and includes the nuclear authorized group at the 50th percentile, results in an impact of $46.7 million.[339]

The conclusions with respect to compensation are in section 6.7.4.

6.7 Pension and Benefits

Issue 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?

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[335] Exh F4-3-1 Attachment 2 page 3. For management the total positions surveyed (71%) and the general industry positions surveyed (74%) are similar.
[336] Exh F4-3-1 Attachment 2 page 3
[337] Tr Vol 16, pages 55-56
[338] Undertaking JT3.2
[339] Exh K17.1 page 19

Issue 6.8 (Oral Hearing) - Are the centrally held costs allocated to the nuclear business appropriate?

6.7.1 Background

OPG's total pension and other retirement benefit costs are comprised of the registered pension plan, other post-employment benefits (OPEBs), and the supplemental pension plan. The benefits received by current employees are also discussed in this section, as the WTW report grouped all benefits together (i.e. benefits for both current employees and retired employees) as part of its analysis of pension and benefits costs.

An analysis of OPG's total costs for pensions and benefits is complicated to some extent by accounting considerations. Pension and benefit costs can be determined (or recovered in rates) on either a cash basis or an accrual accounting basis. The accrual accounting basis represents the method used for financial statement reporting purposes and is based on the underlying accounting standard for pension and OPEB costs. Generally, under this approach the estimated cost of the benefits that were earned by employees in a given year are recognized as an expense. The cash basis represents the employer cash contributions made to the pension plan(s) and the actual benefit payments made in respect to OPEBs for a given year.[340] There can be significant differences between the cash number and the accrual number, as indeed there are for OPG.

Historically OPG has sought to recover its pension and benefit expenses on an accrual basis. However, in EB 2013-0321, the OEB ordered OPG to recover its pension and OPEB costs on a cash basis pending the completion of a generic consultation on the recovery methodology for pension and OPEB costs. As part of that decision, the OEB further authorized the creation of a variance account to record the difference between the cash amounts and the accrual amounts.[341] As this generic consultation was still in progress during the course of this hearing, OPG proposed to continue recovering its pension and OPEB costs on a cash basis and to record the difference between cash and accrual in the variance account.

[340] Tr Vol 16, page 72
[341] EB-2013-0321 Decision with Reasons, pages 87-89. The OEB did not make a generic finding that cash would always be preferred to accrual. The OEB was concerned about what was happening to the accrual amounts that were being recovered (the accrual number at that time was significantly higher than the cash number) and determined that the cash method (with a variance account) would be used until a generic proceeding was held.

Although OPG is seeking to recover its pensions and benefits costs on a cash basis, it has also provided the forecast costs on an accrual basis in order to present an estimate of the amounts that are expected to flow into the cash vs. accrual variance account over the test period. The table below present the total test period pension and OPEB costs for the nuclear business (excludes current benefits) on both a cash and accrual basis.[342]

Table 26

Test Period Pension and OPEB Costs $ Millions	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan	Total
Pension and OPEB Costs - Cash Basis						
Pensions	200.0	202.9	243.5	247.9	250.6	**1,144.9**
OPEBs	91.1	95.7	99.9	104.3	108.5	**499.5**
Total Cash	**291.1**	**298.6**	**343.4**	**352.2**	**359.1**	**1,644.4**
Pension and OPEB Costs - Accrual Basis						
Pensions	214.4	174.0	166.2	163.5	163.8	**881.9**
OPEBs	169.8	174.5	178.5	182.7	187.0	**892.5**
Total Accrual	**384.2**	**348.5**	**344.7**	**346.2**	**350.8**	**1,774.4**
Difference - Cash vs. Accrual	**-93.1**	**-49.9**	**-1.3**	**6.0**	**8.3**	**-130.0**

Pensions and OPEBs are clearly a very significant component of OPG's total compensation package. The annual numbers over the test period range from $291 million to $359 million on a cash basis and from $345 million to $384 million on an accrual basis. OPG's total compensation costs average $1,605 billion per year over that same period.[343]

What is also apparent is that OPEBs form a large component of the total pensions and benefits costs. On an accrual basis OPEBs cost essentially the same amount as the registered pension plan from 2017-2021.

The high cost of OPG's pension plan has been an area of concern for several years. In the previous cost of service application (EB-2013-0321) the OEB disallowed $100

[342] Test period pension and OPEB cash amounts are taken from Exh N1-1-1, page 7, Chart 3.1.1A, test period pension and OPEB accrual amounts are taken from Exh N1-1-1, page 10, Chart 3.1.2.
[343] Exh F4-3-1 page 6 Figure 3. Note that OPG uses the accrual numbers in calculating its pension and benefits components of total compensation in this Figure.

million in each of the two test years largely on account of excessive compensation, including pension costs. The OEB observed that “OPG’s pension plan is very generous”, and that the evidence showed that OPG’s pensions as a percentage of base pay was approximately 33% more generous than its comparator group. The OEB also expressed concern over the high employer-employee contribution ratio, which ranged between 3:1 to 5:1 depending on the year and the method of calculation.[344]

The *Report on the Sustainability of Electricity Sector Pension Plans* (better known as the Leech Report), which was released in August 2014, also highlighted a number concerns regarding the sustainability and affordability of OPG’s registered pension plan. Among its many findings were:

- Compared to private sector plans, OPG’s defined benefit plan was “generous, expensive and inflexible.
- OPG bears all of the risks related to plan performance, which increases both the amount and volatility of pension costs, which are ultimately born by ratepayers.[345]
- It does not appear that high pension costs have been offset by lower salaries.[346]
- The plans are far from sustainable.[347]

Amongst other recommendations, the Leech Report recommended that OPG move to a 50:50 (i.e. 1:1) employer-employee contribution ratio over a period of 5 years (the report was released in 2014).[348]

The Auditor General of Ontario was also critical of the level of OPG’s spending on pensions in its 2013 report. The Auditor General observed that OPG’s pension plan was much more generous than that of the public service at large. In particular the Auditor General was critical of OPG’s employer-employee contribution ratio, which tended to range from 4:1 to 5:1 at OPG, but was 1:1 in the public service.[349]

OPG was itself becoming quite concerned about the costs of its pensions and OPEBs by at least 2011. In that year it retained Towers Watson (now Wilson Towers Watson) to prepare a report outlining the challenges OPG would face in continuing to fund pensions and OPEBs. The report’s conclusions included: “OPG’s [pension and benefits] plans are

[344] EB 2013-0321, Decision with reasons, pages 77-80
[345] Leech Report, Exh K16.2, page 35
[346] Ibid., page 37
[347] Ibid., page 38
[348] Ibid. page 39
[349] 2013 Annual Report of the Office of the Auditor General of Ontario, page 166

unsustainable" and "the risks of costs escalating far beyond an affordable level is very plausible".[350] OPG testified in the hearing that the sustainability of its pension and benefits programs had materially improved since Towers Watson report was prepared.[351]

6.7.2 Pensions and Benefits Benchmarking

NOTE: This section has been redacted as it contains confidential information. An un-redacted copy is provided in Schedule B, which is available only to those who have been granted access to that information by the OEB

OPG's costs for pensions and retirement benefits are significantly above market. The WTW Report includes a section on pensions and benefits. Unfortunately for the purposes of this analysis, "benefits" in the WTW Report includes both benefits for retirees (OPEBs) and for current employees. Regardless, the WTW Report concludes that overall OPG's pensions and benefits are approximately 32% more generous than the market median.[352]

A confidential Benefit Index Report prepared for OPG by AON Hewitt in 2013 came to similar conclusions. The Benefit Index Report assessed the value of OPG's salaried employee benefits program for the PWU compared to the benefit programs of 16 other companies, which had been selected by OPG.[353] The report covers benefits for both current and former employees, and pensions.

With respect to pensions and post-retirement benefits, the Benefit Index Report found that OPG's plans were significantly more generous than those of its peers. [redacted]

[350] Exh K16.2 pages 106 and 115
[351] Tr Vol. 16 pages 132-134
[352] Exh F4-3-1 Attachment 2, page 27. The numbers vary slightly as between the three OPG groups: PWU, the Society, and management.
[353] Exh L-6.6 Schedule 1 Staff 157 Attachment 2 p. 3 (confidential).
[354] Ibid., p. 35.
[355] Ibid., p. 49.
[356] Ibid., p. 67.

[redacted]

[redacted] When considering all of OPG's benefits together (pre and post-retirement), AON concluded that OPG fell between the second and third most generous companies, and was 11% above market.[358]

OPG was asked to calculate what the revenue requirement impact would be if its overall benefits package was at market. OPG responded that neither it nor its consultant were able to perform such a calculation.[359]

Taken together, the WTW Report and the AON Benefit Index Report clearly demonstrate that OPG is significantly above market respecting its pensions, OPEBs, and benefits for existing employees.

6.7.3 Employer-Employee Contribution Ratio[360]

As observed by the OEB, the Leech Report and the Auditor General, one of the reasons that OPG's pension and OPEB costs are so high is the relatively low level of contributions made to the RPP by OPG's employees.

The exact ratio varies somewhat depending on the year and the method of calculation. In OPG's view, the contribution ratio as of 2015 was about 3:1, and they expect that the ratio will be about 2:1 in 2017.[361] The improved ratio is the result of its most recent collective agreements with the PWU and the Society, which included increased employee contributions (in exchange for the lump sum payment and the share performance plan).

Although it is certainly encouraging that the employer-employee contribution ratio is getting closer to 1:1, OEB staff has concerns regarding the method that OPG uses to

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[357] Ibid., p. 77.

[358] Ibid., p. 31.

[359] Technical conference, volume 3, pp. 117-118.

[360] Please note that in section 6.7.3 the numbers used by OEB staff to calculate the employer-employee contribution ratio are on a company wide basis, and not just for nuclear. This is because OEB staff does not know the employee contribution past 2018. OPG also presents the ratio on a company wide basis in its application. OEB staff understands that the ratio for the nuclear business only would be essentially the same as the company wide ratio, as it is based on the same unions and the same collective agreements.

[361] Exh F4-3-1 page 16 Figure 10.

calculate the ratio. OPG's method is to take the cash amount it contributes to the RPP and measure that against the total contributions of its employees.[362]

In OEB staff's view, this creates a misleading picture of the amounts actually being contributed by OPG compared to the amounts being contributed by OPG's employees. OPG's calculation excludes the additional special payments (contributions) that OPG is required to make into the RPP when the Plan is in an underfunded position. Special payments amount to $55 million in 2017 and 2018[363], and were as high as $131 million as recently as 2015.[364]

OPG states that it does not include this as part of its contribution ratio calculation since by law the Company is required to fully fund the special payments[365] (the costs and risks related to fund performance, as observed by the Leech Report, rest entirely with OPG). OEB staff submits that it is not appropriate to exclude special payments from the calculation of the contribution ratio. The overall purpose of such a ratio is to effectively compare OPG's annual cash obligations for the provision of its retirement benefits to that of the employees. Special payments are a part of OPG's contribution directly into the RPP. The fact that employees are not responsible for similar payments is not a reason to ignore these costs for the purpose of the calculation; indeed the very purpose of the contribution ratio is to measure the relative amounts contributed by the employer and the employee. Further, the Auditor General of Ontario included deficit payments when it calculated the contribution ratio in its 2013 Report.[366] If special payments are included in the calculation, the ratio for 2017 and 2018 moves to approximately 2.7:1.[367]

OPG also does not include the annual cash payments it makes in respect to its OPEBs in the calculation of its contribution ratio. OPG's rationale is that there is no requirement to make contributions to (or pre-fund) OPEB Plans, Payments are only made as these benefits are drawn by retirees (these payments are entirely employer funded).[368] However, as observed above OPEBs are a very significant portion of OPG's total costs for its retired employees, both on a cash and accrual basis. By focusing only on the

[362] Employee contributions can only be measured on a cash basis as it is derived from the actual cash payments they make into the RPP, there is no accrual alternative to calculating this.
[363] AON Actuarial Valuation as at January 1, 2016 for OPG Inc. Pension Plan, p. 22 that was provided in the response to Staff IR #156. The forecast amounts of special payments for 2019-2021 have not been broken out.
[364] 2015 Report to Members, page 2.
[365] Tr Vol. 16 page 103
[366] 2013 Annual Report of the Office of the Auditor General of Ontario, p. 166. The AG states that the employer contribution in 2012 was $370M. This includes current service costs of $225M, a deficit payment of $65M, and a voluntary payment of $80M.
[367] K16.2 OEB Staff Compendium, page 50, Table 3 and Table 4
[368] Tr Vol 16 pages 104-105.

RPP, OPG's presentation of its total contribution ratio ignores a sizeable portion of its annual cash spending on the retirement benefits that ratepayers are being asked to pay for.

Further, the Ontario public sector in general is moving towards requiring a 1:1 contribution from employees for OPEBs. OPG has no immediate plans to do the same, or to require any employee contribution to OPEBs at all, noting that post-retirement benefits are part of the collective agreements.[369] If OPEBs were added to the contribution ratio (on a cash basis) the contribution ratio for 2017 and 2018 would be approximately 3.8:1.[370]

The contribution ratio for 2019-2021 is confidential. OPG's contribution to the registered pension plan (which is not confidential) is forecast to be $198 million (plus a special payment of $101 million) in 2019, $204 million (plus a special payment of $101 million) in 2020, and $210 million (plus a special payment of $98 million) in 2021.[371] [redacted]

OPG's calculation of its contribution ratio for 2019-2021 again excludes special payments. If special payments were included (as Board staff submits they should be), the contribution ratio would be approximately [redacted]. Payments made in respect to OPEBs would also add an additional approximately $100 million (cash basis) or $200 million (accrual basis) to OPG's costs for retirement benefits. These amounts are also not included in its calculation of the contribution ratio. [redacted]

[redacted]

369 Tr Vol 16 page 108.
370 Exh K16.2 Table 3 and Table 4. Note that the ratio is calculated by necessity using the cash amounts, as there is no accrual "number" for the employee contribution. However, the accrual number for OPG's contribution (i.e. the amount of the liability that actually arises in the year) is higher than the cash number.
371 J 16.6
372 Exh F4-3-1 page 16, Table 10.
373 Exh L-6.6-Staff-147(h) (confidential).

[redacted]

OPG was able to negotiate increased employee contributions for its most recent collective agreements with the Society and the PWU. These agreements will be in place until March 31, 2018 and December 31, 2018 respectively. [redacted]

[redacted]

6.7.4 Conclusion – Compensation and Pensions

OPG has made progress in controlling its overall compensation costs. In particular, FTE numbers and total direct compensation appear to be close to or marginally above market. Although the exact level by which OPG is above market for total direct compensation is still open to debate – for example OEB staff do not support the exclusion of the share performance plan and the lump sum payment from the calculation and the use of the 75th percentile for nuclear jobs - this is an improvement over recent applications.

However, OPG's overall requested recovery for compensation costs remains unreasonably high. The chief driver of this is OPG's extremely generous pensions and benefits programs. As described in the evidence, the costs of these programs are well above what is typical in the market. OEB staff appreciates that OPG cannot unilaterally

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[374] Exh L-6.6-Staff-157, Attachment 1, pages 12 and 15.
[375] Tr Vol 16 pages 164 and 166 (confidential).
[376] Tr Vol 16 page 165 (confidential).
[377]Exh L-6.6-Staff-147(h) (confidential).

change the terms of its collective agreements, and that indeed it was able to secure somewhat higher employee pension contributions in its latest round of collective bargaining in exchange for the lump sum payment and share performance plan. OEB staff further understands that differing circumstances between different companies can sometimes account for some of the differing benchmarking results. However, it is not reasonable to pass these excessive costs on to ratepayers. OPG has persistently compensated its employees at a materially higher level than its comparators, as selected by several expert consultants.

In addition, OPG's overall nuclear performance benchmarking results as prepared by ScottMadden and discussed in section 6.2 reveal that OPG is not an efficiently run operation. If OPG and its workforce were producing above benchmark results on TGC, for example, one might be able to justify higher compensation. In fact, the opposite is true: OPG both pays its employees above market, and performs poorly on its overall efficiency metrics.

It is difficult to calculate an exact number to account for excessive compensation and poor overall efficiency. There is no clear dollar number that can be derived to account for OPG's overall poor efficiency as measured by, for example, TGC. The costs of paying its employees above the 50th percentile (as opposed to using the +/-10% threshold identified by WTW) for total direct compensation (which excludes pensions and benefits) has been calculated as between $29.6 million and 46.7million annually. With respect to pension and benefit costs, OPG was unable to provide information on what the cost savings would be if it were at market instead of significantly above market.[378] [redacted]

Considering all factors, OEB staff is recommending an annual disallowance of $50 million specifically on account of excessive employee compensation which is in addition to the $40 million reduction suggested by OEB staff for base OM&A. However, this incremental reduction for excessive compensation is less than the disallowance by the OEB in the previous cost of service proceeding, which was $100 million per year, almost all of which was based on excessive compensation.

6.8 Corporate and Centrally Held Costs

[378] Technical conference transcript, vol. 3, pp. 117-118.

Issue 6.7 (Oral Hearing) - Are the corporate costs allocated to the nuclear business appropriate?
Issue 6.8 (Oral Hearing) - Are the centrally held costs allocated to the nuclear business appropriate?

6.6.1 Corporate Costs

Support service groups (Business and Administrative Services, Finance, People & Culture, Commercial Operations & Environment and Corporate Centre) provide services and incur costs in support of the nuclear business. The allocation methodology was reviewed in the second cost of service proceeding (EB-2010-0008), including a report prepared by Black and Veatch. The methodology was reviewed again in the third cost of service proceeding (EB-2013-0321), including a report prepared by HSG Group.

From 2011 to 2015, OPG implemented Business Transformation to improve its cost structure and create a more efficient and effective organization. Business Transformation led to the creation of a centre-led organization structure. In the EB-2013-0321 decision, the OEB directed OPG to undertake an independent benchmarking study of corporate support functions and costs, and to show the results in a manner that enabled comparison before and after Business Transformation.

OPG filed a study conducted by the Hackett Group on OPG regulated corporate costs (i.e., not just the nuclear allocation).[379] The peer group was 19 North American companies. Hackett found that OPG's regulated corporate function costs declined 10 per cent from 2010 to 2014 while total regulated OPG headcount declined 11 per cent. Hackett also found that OPG's overall cost benchmark performance at the functional level improved between 2010 and 2014.

The corporate support groups benchmarked were IT (cost/end user), HR (cost/employee), Finance (cost/revenue) and Executive and Corporate Service (ECS) (cost/revenue). The costs of the functions benchmarked represent 58% of OPG's total corporate costs.[380] The quartile benchmark results were provided in response to an interrogatory.[381] Hackett concluded that OPG's IT function was a Q1 performer, finance and HR were Q3 and ECS was Q4. OPG's ECS results were the worst of the peer group. If OPG's corporate wide ECS costs had been at median in 2014, expenses would have been reduced by $81 million.

[379] Exh F3-1-1 Attachment 1
[380] For 2014: $318.2 million (Exh F3-1-1 Attachment 1 page 11)/$549.2 million (Exh F3-1-1 Table 1)
[381] Exh L-6.7-Staff-169 Attachment 1

During cross-examination, CME requested a calculation of the test period revenue requirement impact of median performance of the finance, and a similar calculation for the ECS function.[382] In response, OPG filed calculations that included all the functions benchmarked by Hackett, not just finance and ECS. The analysis, for all functions combined, indicated that forecast revenue requirement is $15 million to $25 million lower than median per year for the test period. OPG noted that the calculation and estimates had not been vetted against Hackett's taxonomy and that use of a static median did not represent a valid comparison for the test period.

The corporate support service costs allocated to the nuclear business for the historical and test period are provided in the table below. OPG states that the costs are relatively flat over the IR term,[383] however, OEB staff notes that there is a significant change from 2015 (the end of Business Transformation) and the 2016 budget and the test period. OEB staff has coded the 2014 cost with benchmarking quartile results. The coding is not exact as certain functions within each group were excluded from the Hackett benchmarking.[384]

Table 27
Corporate Support Service Costs

	$million	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	55.9	54.6	52.7	46.8	45.3	43.7	43.7	42.1	40.8
3	IT Support Cost	35.9	36.6	37.3	41.8	43.7	42.6	42.3	42.7	43.2
4	Total IT Costs*	91.8	91.2	90.0	88.6	89.0	86.3	86.0	84.8	84.0
5	Supply Chain*	48.6	42.5	41.1	47.6	47.3	46.7	47.8	49.2	50.3
6	Real Estate*	88.4	83.3	82.5	89.9	94.5	92.8	95.0	95.5	98.7
7	OM&A Project Costs	17.9	10.2	17.4	18.9	15.3	13.3	12.2	12.8	13.1
8	Total Business and Admin Service	246.7	227.2	231.0	245.0	246.1	239.1	241.0	242.3	246.1
9	Finance*	46.3	44.4	35.6	40.2	41.5	39.4	39.0	38.8	39.9
10	People and Culture*	91.6	98.2	95.8	92.4	96.2	95.3	97.8	98.5	100.5
11	Commercial Ops and Environment	14.7	19.5	16.8	20.4	20.2	18.9	19.9	19.6	21.8
12	Corporate Centre*	29.2	26.9	39.6	44.3	44.9	44.5	45.0	45.8	45.8
13	**TOTAL (lines 8-12)**	**428.5**	**416.2**	**418.8**	**442.3**	**448.9**	**437.2**	**442.7**	**445.0**	**454.1**
14	2016 Actual				426.2					
15	1% CAGR on 2014 Actual			420.4	424.6	428.8	433.1	437.4	441.8	446.2
16	Nuclear FTEs	8593.7	8431.7	8119.7	8729.7	8808.4	8768.6	8672.0	8437.1	8299.2
	* "Benchmarked" by the Hackett Group									
	Source: Exh F3-1-1 Table 3 and 7, Undertaking J14.2, Exh F4-3-1 Attachment 1									
										Q1
										Q2
										Q3
										Q4

[382] Undertaking J20.3, Undertaking J20.4
[383] AIC page 6
[384] Exh F3-1-1 Attachment 1 page 7

Several parties questioned Hackett's methodology for IT benchmarking and the use of LAN ID for end user equivalents. There were 12,267 end user equivalents in 2014, while the regular OPG wide regular head count was 9,292.[385] The difference of 2,975 indicates a very large number of non-regular staff and contractors who have been issued LAN ID. In cross-examination, OPG stated that it had reviewed the definition of LAN ID with Hackett,[386] however, it is not clear whether "doing at least 10 percent of efforts using and accessing systems" is a consistent definition applied to all peers. OEB staff does note that nuclear FTEs (line 16 of the table above) in 2021 are lower than in 2014, and that the forecast total IT costs (line 4) follow this trend.

The nuclear business allocation of People and Culture expenses increase from $98.2 million in 2014 to $100.5 million in 2021. While the increase is small, OEB staff expected the expenses to be lower as forecast FTEs are lower.

ECS costs benchmarked very poorly in 2014, and this is indicated in Supply Chain, Real Estate and, to some extent, Corporate Centre costs in the table above. The compound annual growth rate from 2014 to 2021 for Supply Chain and Real Estate is above inflation at 2.5%. The compound annual growth rate for Corporate Centre for the same period is well above inflation at 7.9%. The Supply Chain increases are related to an equipment reliability initiative and inflation. The Real Estate increases are related to lease costs for 700 University and inflation. The Corporate Centre increases are related to a transfer of staff from other areas, e.g. finance. The historical and forecast variances for all corporate costs are characterized as stable.[387] OEB staff submits that these compound annual growth rates would continue to result in ECS performance in the fourth quartile. OEB staff submits that OPG's responses in cross-examination[388] and in undertaking J20.3 indicate that there are no plans to address this performance.

Similar to nuclear operations OM&A, OPG's 2016 nuclear corporate support service budget for the nuclear business was a step increase over 2015. Again, similar to nuclear operations, the 2016 actual nuclear corporate support service OM&A was lower than budget (line 14 of the table above). OEB staff has included a 1% increase on the 2014 total nuclear corporate support service costs at line 15 of the table above. The 2015 and 2016 actuals are close to the costs projected by the 1% increase. In the test period, the 1% limit would reduce revenue requirement by $3.2 million to $20.1 million per year, for a total test period reduction of $40.5 million. OEB staff submits that this

[385] Exh F3-1-1Attachment 1, page 6
[386] Tr Vol 20 pages 18-19
[387] Exh F3-1-2
[388] Tr Vol 21 pages 127 -130

overall approach on nuclear corporate support services costs is similar to the approach taken in OPG's response to undertaking J20.3.

As noted in the Custom IR section 11.2, OPG proposes to apply a stretch factor to nuclear corporate support service costs in the test period. OEB staff supports the application of a stretch factor to these costs.

6.8.2 Centrally Held Costs

The nuclear business is allocated company-wide costs that are held centrally, including certain pension and OPEB costs, insurance, performance incentives and IESO non-energy charges.

The application presents compensation related cost information on an accrual basis, consistent with OPG's business plan. A negative adjustment reflecting the forecast differential between pension and OPEB accrual costs and cash amounts is included as a separate entry in centrally-held costs. The OEB staff submission regarding pensions is in section 6.7.

6.9 Depreciation

Issue 6.9 (Primary) - Is the proposed test period nuclear depreciation expense appropriate?

OPG seeks approval for depreciation and amortization expense of:

Table 28
Depreciation and Amortization Expense

$ millions	2017	2018	2019	2020	2021
	367.0	395.0	400.3	541.5	316.7

Source: AIC page 121

OPG indicated that there have been no changes in asset service lives for OPG's regulated business compared to those recommended by the Gannett Fleming Depreciation Study which the OEB accepted in the EB-2013-0321 proceeding except for the end-of-life (EOL) dates for the nuclear stations. The changes in EOL are as follows:

Table 29
Nuclear Station End of Life

	Effective Jan 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 Darlington EOL date was revised based on the refurbishment schedule of the Darlington Refurbishment Plan. The Bruce units EOL's were revised as a result of the Amended and Restated Bruce Power Refurbishment Implementation Agreement. OPG extended the Pickering Units 5-8 EOL to December 31, 2020 due to the confidence achieved through work on the Fuel Channel Life Extension Project and execution of inspection and technical work programs.[389] OPG is undertaking initiatives to extend Pickering EOL beyond 2020. OPG indicated that they will apply for an accounting order related to any future changes to the Pickering EOL date.

Furthermore, OPG indicated that if material changes to service life estimates are required by generally accepted accounting principles to be implemented in advance of OPG's next IR term, OPG would apply for an accounting order in accordance with the requirements set out in EB-2012-0002 and EB-2013-0321 decision and orders. In particular, this would be for a change in the EOL dates for OPG's prescribed nuclear facilities and an accounting change impacting the calculation of OPG's nuclear liabilities other than as a result of an ONFA Reference Plan update. The impact of the change is subject to a $10 million annualized revenue requirement materiality threshold and is not reflected in any approved deferral and variance account.

OEB staff notes that even though the initiatives to extend Pickering operations beyond 2020 are underway and OPG is seeking to recover the associated costs, OPG has chosen not to incorporate the extension for depreciation purposes. Instead OPG has proposed to request a deferral and variance account to capture the impact of an EOL date revision, if it should occur. OEB staff does not take issue with this approach as there is uncertainty surrounding the extension. OPG has indicated the EOL date is

[389] Exh F4-1-1, page 6

expected to be reassessed in the future when further technical work confirms at a high confidence that Pickering would be fit for operations beyond 2020. As such, OEB staff does not take issue with the revised EOL of the prescribed facilities.

OEB staff also supports OPG's proposal to request an accounting order should the criteria as indicated by OPG be met. This methodology has been approved in past decisions of the OEB.

OPG is proposing not to perform an independent review of service life estimates five years from the last review, which would be scheduled for 2018 based on 2017 year end asset net book values. Instead, OPG is planning to conduct the independent study after the refurbished Darlington Unit 2 is scheduled to return to service in 2021 based on 2020 year end asset net book values. The results of the study will be considered for implementation effective January 1, 2022, which coincides with OPG's next rate-making term. OPG believes this approach to be more meaningful and efficient.[390] OEB staff takes no issue with OPG's proposal. OEB staff notes that OPG's Depreciation Review Committee (DRC) performs regular reviews of service lives of generating stations and a selection of asset classes over a five year cycle. OEB staff is of the view that the DRC's review combined with the requirement to request a deferral and variance account should there be a material change in service life, is sufficient to delay the performance of an independent review of service lives until Darlington Unit 2 is returned to service in 2020.

6.10 Income and Property Taxes

Issue 6.13 (Primary) - Are the amounts proposed to be included in the test period nuclear revenue requirement for income and property taxes appropriate?

6.10.1 Background

OPG is seeking approval of the following income tax expense and property tax expense:

[390] Exh L-6.9-Staff-175

Table 30
Income and Property Tax Expense

($million)	2017	2018	2019	2020	2021	Total
Income tax expense	(6.7)	(18.4)	(18.4)	59.2	(5.0)	10.7
Property tax expense	14.6	14.9	15.3	15.7	17.0	77.5
Source: AIC pages 125 and 127						

OPG indicated that it has applied the same principles and methodologies to income tax expense and property tax expense as in EB-2013-0321. OPG projects regulatory tax losses in 2018 and 2019 and regulatory taxable income in 2017, 2020 and 2021.The regulatory tax losses in 2018 and 2019 are carried back to reduce regulatory taxable income in 2017. Taxes are then further reduced by Scientific Research and Experimental Development (SR&ED) investment tax credits (ITCs), resulting in negative tax expense for 2017 to 2019 and 2021. OEB staff has no concerns with the cumulative taxes for the entire Custom IR period except for the treatment of SR&ED ITCs as below.

6.10.2 Utilization of SR&ED ITCs

OPG claims non-refundable SR&ED ITCs, which are used to reduce OPG's overall statutory corporate taxes. OPG forecasted $18.4 million of SR&ED ITCs for regulatory purposes annually over the test period to reduce regulatory tax expenses.[391] These SR&ED ITCs can be carried forward if unused in a particular year.

From 2013 to 2015, where taxes for the nuclear and hydroelectricity businesses were calculated on a combined basis, OPG used SR&ED ITCs to reduce its nuclear income taxes. The SR&ED ITCs used included the ITCs earned by the nuclear business in the year plus previously unrecognized nuclear ITCs upon the resolution of tax audits.[392] However, OEB staff noted that from 2013 to 2015, the nuclear business has been attributed nuclear losses every year.[393] In the technical conference, when questioned about how OPG was able to use the nuclear ITCs when it had no tax expense, OPG's witness stated that the ITCs utilized "represents the regulated portion of the SR&ED ITCs utilized to reduce OPG's corporate income taxes payable".[394]

OEB staff submits that even though the ITCs were used in OPG's corporate tax return, regulatory taxes are different from corporate taxes. For the most part, regulatory taxes

[391] Exh N2-1-1, Table 2
[392] Exh L-6.10-Staff-188 – 2013 $37 million, 2014 $44.5 million, 2015 $37.7 million
[393] JT3.13, Attachment 1 – 2013 ($358.9 million), 2014 ($286.7 million), 2015 ($162.2 million),
[394] Technical Conference Tr Vol 3, page 70

simulate what a utility would incur for actual corporate tax expenses. However, there are certain areas where the OEB has required specific regulatory treatment that differ from that required for corporate tax purposes. For example, regulatory assets and liabilities are to be excluded from regulatory taxes regardless of the corporate tax treatment.[395] Therefore, the treatment of certain items for corporate tax purposes may be different than for regulatory tax purposes.

In the oral hearing, OPG's witness stated the following regarding the treatment of tax losses:

> … we then used to attribute our combined regulatory taxes between technologies, such that the – and our approach has been if there is a loss in one business that is calculated like you see here, it really is first applied to reduce the positive taxable income that may be attributed to our hydroelectric operations. That's an approach that we have applied consistently through our filings.[396]

Furthermore, when asked for their comments on the scenario where ITCs that were earned by the nuclear business would only be used to reduce taxes related to the nuclear business, OPG's witness stated the following:

> I don't think that would be appropriate because, as I've stated, the ROE's set on a combined basis for the company, and so to look at a nuclear taxable position or tax loss position, which is what you would need to do when you're applying the SR&ED ITCs, would not be appropriate. It's appropriate to say that the nuclear business generated, you know, X amount of ITCs. That's something that's easily traced and determinable and ascertainable, because the work was done…[397]

OPG had nuclear tax losses from 2014 to 2016 and therefore, was not able to use the nuclear ITCs against nuclear taxes during this period. Instead, OPG used the nuclear ITCs against hydroelectric taxes during this period, similar to OPG's treatment of business losses. However, as the hydroelectric facilities payment amounts in this proceeding are being set through an IRM using a mechanistic approach instead of a cost-based application, where taxes would be forecasted and included in the revenue requirement, the benefits of reduced tax expenses from the usage of ITCs against hydroelectric taxes will not flow to rate payers. If OPG had carried forward the nuclear ITCs, the benefits of the ITCs would flow to rate payers in this application as the ITCs would be used in the test period to reduce the cumulative nuclear taxes OPG is forecasting over the 2017 to 2021 period. Therefore, OEB staff submits that going forward, SR&ED ITCs should be utilized by the business segment that earned the ITCs. If the business segment does not have any income taxes available to be reduced by the

[395] Example of this in the 2006 Electricity Distribution Handbook (RP-2004-0188) page 61
[396] Tr Vol 21, page 135
[397] Tr Vol 21, page 139

ITCs, then the ITCs should be carried forward until there are income taxes generated so that the ITCs can be used in the future. Nuclear ITCs should not be used to reduce hydroelectric tax expense, as OPG has done in 2014 and 2015, instead of carrying the nuclear ITCs forward to be used in the future. The ITCs of each business segment are directly derived based on the underlying expenditure giving rise to the ITCs. Therefore, ITCs that result from expenditures of a nuclear nature would be attributed to the nuclear business. The regulatory principle of cost causation with respect to OPG's technologies suggests that ITCs (or other benefits or credits) earned by a business segment should be used by the business segment that generated the benefit (or cost). OEB staff notes that OPG indicated certain adjustments will have to be made in calculating nuclear taxable income or loss in order to determine how much nuclear ITCs can be used by the nuclear business in a particular year.[398] However, OEB staff is of the view that for this application, OPG has already calculated taxes for the nuclear business separately on a stand-alone basis and these adjustments are not administratively burdensome to OPG's ability to align with the principle of cost causation with respect to the technologies.

In addition, the nuclear and hydroelectric business segments are under different rate setting regimes in this rate application. At this point, OEB staff does not know whether or not the rate-setting regimes for nuclear and hydroelectric prescribed facilities will be the same in 2022. In this application, the nuclear payment amounts are being set under a Custom IR application while the hydroelectric payment amounts are being set under an incentive rate mechanism. As such, the nuclear and hydroelectric ROEs are no longer determined contemporaneously on a combined basis as in past proceedings and cost-based payment amounts may no longer align to the same timeframe in future applications. The same is true for the nuclear and hydroelectric regulatory taxes. The risk is that the ITCs would continue be used interchangeably between business segments prior to any regulatory review through a cost-based application. OEB staff submits that the utilization of ITCs should no longer be on a combined basis going forward and that any unutilized amounts applicable to a particular business segment should be carried forward. Doing so on a combined basis may lead to ratepayers losing the benefit of ITCs when the payment amounts determined through cost-based rate applications are determined at different times.

SR&ED ITCs Recorded in Variance Account

OEB staff notes that the OEB accepted the settlement proposal filed on March 6, 2017.[399] The settlement proposal included issue 9.6, where OPG sought approval for

398 Tr Vol 21, pages 138
399 Tr Vol 9, page 1

the continuation of its existing deferral and variance accounts as described in Exh H1-1-1 and the Parties agreed that the proposed continuation of deferral and variance accounts is appropriate on the basis of OPG's evidence. The settlement proposal also included issue 9.1, where the Parties agreed 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. OEB staff acknowledges that this would encompass the Income and Other Taxes Variance Account, however, OEB staff is of the view that the OEB may wish to clarify the nature and type of costs included in the scope of this account on a prospective basis and so OEB staff is making this submission to assist the OEB in this regard.

OPG has the Income and Other Taxes Variance Account approved since EB-2007-0905. This account includes, among other things, the financial impact on the revenue requirement from the differences in payments in lieu of income or capital taxes that result from assessments or reassessments. With regards to SR&ED ITCs, OPG recognizes 75% of the estimated ITCs for taxation years that are subject to a tax audit. The final percentage of recognition per the tax audit results may differ from the 75% that was reflected in approved payment amounts. The revenue requirement difference between 75% of approved ITCs and the percentage as per the tax audit multiplied by the approved ITCs is recorded in the Income and Other Taxes Variance Account.[400] OPG confirmed that the true up from the 75% of ITCs to the percentage of recognition resulting from the audit is not equivalent to a true up to the actual ITC claimed.[401] There can be differences between forecasted ITCs approved in payment amounts and actual ITCs earned, not just differences in the percentage of recognition in approved ITCs. The scope of the Income and other Taxes Variance Account includes results from tax reassessments, OEB staff is of the view that this should include a true up to the actual ITCs claimed per the tax audit and not just a true up of the percentage of recognition per the tax audit for the reasons given in the sections below.

From 2013 to 2015, the difference between actual ITCs earned and forecasted ITCs included in payment amounts are as follows:

[400] Exh F4-1-2 page 10
[401] Exh L-6.10-Staff-189 re-filed Dec. 22, 2016

Table 31
Historical ITCs

Year	Forecasted ITCs ($million)	Actual ITCs ($million)	Difference ($millions)	Difference %
2013	14.1	35.5	21.4	32%
2014	9.4	33.0	23.6	35%
2015	9.4	31.9	22.5	33%
Total	**32.9**	**100.4**	**67.5**	**100%**

Source: L-6.10-Staff-189 re-filed Dec. 22, 2016

OEB staff notes that OPG has historically excluded the impact to income tax expense from these variances in the Income and Other Taxes Variance Account as they are not differences pertaining to the percentage of ITC recognized but are differences between actual and forecast underlying qualifying expenditure levels.

OPG has forecasted SR&ED ITCs to be $18.4 million for each year from 2017 to 2021 and included this amount as part of its income tax expense calculation. In an update of interrogatory responses filed along with the first impact statement, OPG identified the ITCs reflected in its 2017 to 2019 Business Plans as shown in the table below:

Table 32
Forecast ITCs

	2017	2018	2019	2020	2021	Total
2017-2019 Business Plan	26.3	26.5	26.9	27.5	25.3	132.5
Included in Current Application	18.4	18.4	18.4	18.4	18.4	92.0
Difference	**7.9**	**8.1**	**8.5**	**9.1**	**6.9**	**40.5**

Source: L-6.10-Staff-189 re-filed Dec. 22, 2016 and Exh N2-1-1, Table 2

OPG has not included the updated ITCs in its updated application as it is below the materiality threshold of an average of $10 million per year over the IR period. However, OEB staff notes that from 2013 to 2015, OPG has a trend of underestimating its nuclear ITCs and this pattern has continued in this five-year application. Combining this historical trend in underestimation and the fact that OPG's most updated information already shows an underestimation of ITCs included in the current application, OEB staff submits that the Income and Other Tax Variance Account should include income tax expense impacts from the true up to actual SR&ED ITCs claimed resulting from tax audits and not just to the ultimate percentage of recognition as per the results of tax audits. Including this within the scope of the variance account will keep ratepayers and OPG whole. Furthermore, it would be unfair to ratepayers if they were to not receive this benefit when OPG has indicated it has better up to date information at this time. OEB staff is of the view that the ITCs in the application should be updated to reflect the most current information available.

7. ASSET SERVICE FEES AND OTHER REVENUES

7.1 Asset Service Fees

Issue 6.11 (Secondary) – Are the asset service fee amounts charged to the nuclear business appropriate?

The nuclear business is charged asset service fees for commonly held assets. The matter was settled by the parties.

7.2 Nuclear Other Revenues

Issue 7.1 (Secondary) – Are the forecasts of nuclear business non-energy revenues appropriate?

Other revenues include isotope sales and revenue from services. These revenues are an offset to the calculation of nuclear revenue requirement. The matter was settled by the parties, and the revised offset amounts are noted in the table at section 11.4.

7.3 Bruce Nuclear Generating Station

Issue 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?

The net of the Bruce lease revenues and costs, calculated in accordance with the OEB approved methodology and generally accepted accounting principles, is used to offset the test period nuclear payment amounts. The application reflects the December 4, 2015 amended Bruce Lease agreement that extended the lease period in line with the Bruce refurbishment. The lease amended rent, fees for services and other provisions to limit OPG's exposure to financial risk over the lease term.[402]

[402] Exh G2-2-1 page 2

In the period 2010-2015, net revenues were positive except for one year. However, over the test period, net revenues are forecast to be negative in each year. The test period net revenues reflect the 2017 Ontario Nuclear Funds Agreement (ONFA) Reference Plan update and the accounting impact of extending the life of the Bruce units. OPG notes in the AIC that net revenues of the lease term to the early 2060s could be positive or negative.

As noted in section 8.2, OEB staff submits that the impact of the provincial approval of a new ONFA contribution schedule (approved on February 28, 2017) and a year-end adjustment to its asset retirement obligation should be reflected in the test period revenue requirement and reduce the negative net revenues related to Bruce.

8. NUCLEAR WASTE MANAGEMENT AND DECOMMISSIONING LIABILITIES

Issue 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?
Issue 8.2 (Primary) - Is the revenue requirement impact of the nuclear liabilities appropriately determined?

8.1 Background

OPG is responsible for the ongoing and long-term management and safe disposition of the radioactive wastes that are generated from the operations of its nuclear facilities and also the decommissioning of its nuclear generating and waste management facilities once their operations cease. For accounting purposes OPG recognizes these costs over the operating life of its nuclear facilities even though the actual cash outlays associated with these costs will not take place until well into the future, for the most part, after the operations of these facilities have ceased.

In recognition that these liabilities will be settled many years after the nuclear generating stations have closed and the nuclear fuel bundles are used, the Province of Ontario and OPG entered into the ONFA to ensure that the required funding will be in place once these liabilities become due. The ONFA sets out OPG’s funding requirements for the nuclear liability costs based on a predetermined set of contributions to two segregated Funds, the Decommissioning Fund and the Used Fuel Fund. The contributions are derived from an ONFA reference plan that calculates OPG's estimated funding liability based on underlying cost estimates and assumptions such as discount rates. ONFA reference plans are required to be updated at least every five-years. The current approved plan is the 2017 ONFA reference plan, which was approved by the province in December 2016 and covers the period 2017-2021. The ONFA Agreement is applicable to the nuclear liabilities of both the prescribed facilities (i.e., Pickering and Darlington) and the Bruce Nuclear Generating Stations (Bruce).

As part of OPG's first payment amount proceeding (EB 2017-0905), the OEB reviewed various methodologies to determine the recovery of OPG's nuclear liability costs. The OEB ultimately approved separate recovery mechanisms for the prescribed facilities and Bruce. The table below summarizes the key components of each OEB approved cost recovery method:

Table 33

Components of the Nuclear Liability Cost Recovery Methodology	
Prescribed Facilities	Bruce Facilities
Depreciation of Asset Retirement Costs	Depreciation of Asset Retirement Costs
Used Fuel Storage and Disposal Variable Expenses	Used Fuel Storage and Disposal Variable Expenses
Low & Intermediate Level Waste Management Expenses	Low & Intermediate Level Waste Management Expenses
Return on ARC in rate base	Accretion Expense
	Less Segregated Fund Earnings/(Losses)

The recovery methodologies are quite similar, the key distinction being that the Bruce operations are not subject to rate regulation. On this basis, the OEB concluded that it would not be appropriate for OPG to recover its nuclear liability costs associated with the Bruce facilities in accordance with principles applicable to a regulated business. Accordingly, the approved methodology for the prescribed facilities includes a Return on rate base (i.e., asset retirement cost – ARC), a concept that is only applicable to regulated utilities, whereas the Bruce recovery is entirely derived from costs calculated in accordance with US Generally Accepted Accounting Principles. In lieu of a return on ARC in rate base, the Bruce recovery methodology uses a GAAP based accretion (interest) expense, less the segregated Fund earnings. These methodologies have been applied in all OPG rate applications since the OEB's EB-2007-0905 decision.

8.2 Test Period Revenue Requirement

As presented in Exhibit C2-1-2, Chart 1, OPG is seeking recovery of the following test period revenue requirement with respect to its nuclear liabilities:

Table 34
Nuclear Liabilities – Revenue Requirement

$ million	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan	Total
Prescribed Facilities	178.4	169.4	193.8	167.1	77.7	**786.4**
Bruce Facilities	208.6	200.5	204.1	210.3	198.1	**1,021.6**
Total	**387.0**	**369.9**	**397.9**	**377.4**	**275.8**	**1,808.0**

OEB staff notes that on December 20, 2016, OPG filed an Impact Statement as Exh N1-1-1 which adjusted its test period nuclear liability revenue requirement for certain material changes that had occurred since OPG submitted its May 27, 2016 pre-filed evidence. This included the projected revenue requirement impact from changes in the nuclear liabilities as a result of the provincial approval of the 2017 ONFA reference plan, which occurred in December 2016. The revenue requirement in the pre-filed evidence had been derived using the approved 2012 ONFA reference plan, which was the reference plan in effect at the time OPG filed its Custom IR application. OEB staff notes that the impact of the Exh N1-1-1 update (i.e., a $396 million reduction in test period revenue requirement) is included within the test period payment amounts presented in the above table.

On March 22, 2017, OPG submitted Exh C2-1-2 to the OEB, which was a second update to its nuclear liabilities primarily as a result of provincial approval of a new ONFA contribution schedule (approved on February 28, 2017) and a year-end adjustment to its asset retirement obligation as reflected in their 2016 audited consolidated financial statements. However, OEB staff notes that unlike the Exh N1-1-1 update noted above, OPG has not proposed to include the impact of this second update in its test period nuclear payment amounts. Instead, OPG has calculated the estimated test period revenue requirement impact associated with this second update, but has proposed to capture it in the Nuclear Liability Deferral Account and the Bruce Lease Net Revenues Variance Account over the test period for consideration in a future rate application. The estimated test period revenue requirement impact that will be captured in the deferral and variance accounts is expected to result in a net credit (refund to ratepayers) of $294.6 million.[403]

OEB staff submits that the intention of the aforementioned variance accounts is to capture the revenue requirement impacts of certain events or transactions that occur after the payment amounts have been set. In this case these are known adjustments to the test period revenue requirement that OPG has proposed to exclude from the payment amounts irrespective of the fact that these payment amounts have not been set. It would not be appropriate to require ratepayers to pay amounts for nuclear liability costs if the underlying estimates are known to be materially inaccurate prior to approving the payment amounts. OEB staff submits that the payment amounts should reflect the best estimates and therefore these impacts should be recognized as a net reduction to the test period revenue requirement.

As part of undertaking J21.2, OPG was asked to provide an updated nuclear liability revenue requirement that takes into account all amounts that OPG has proposed to capture within the Nuclear Liability Deferral Account and the Bruce Lease Net Revenue Variance Account. OEB staff submits that the information provided in Chart 1 of the response to undertaking J21.2 should form the basis of the nuclear liability revenue requirement for the test period, as presented in the following table:

Table 35
Nuclear Liabilities – Revenue Requirement (Revised)

$ million	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan	Total
Prescribed Facilities	124.2	115.6	137.2	114.3	29.8	**521.1**
Bruce Facilities	193.1	187.4	195.1	205.3	201.2	**982.1**
Total	**317.3**	**303.0**	**332.3**	**319.6**	**231.0**	**1,503.2**

8.3 Recovery Methodology Implications due to Zero Contributions to the Segregated Funds

[403] Exh C2-1-2, pages. 4-5 indicates that the estimated revenue requirement impact of the new approved ONFA contribution schedule is a reduction of $170.8M and an increase of $51.2M for the prescribed facilities and Bruce facilities respectively. The estimated revenue requirement impact associated with the adjustment to the asset retirement obligation and discount rate used to determine variable expenses is a reduction of $95M and $80M for the prescribed facilities and Bruce facilities respectively. Therefore the net revenue requirement of all these amounts is a net reduction of $294.6M (or $170.8-$51.2+$95+$80)

The costs that are expected to be incurred after the nuclear facilities are shut down are referred to as OPG's long-term nuclear liability programs and represent the costs that will actually be funded through ONFA (via the segregated Funds).[404] This excludes any costs associated with OPG's shorter-term nuclear programs, which are referred to as their "internally funded" costs, and include costs incurred to manage and store used fuel waste during the operations of the facilities[405] These "short-term" costs are not included in the ONFA and therefore cannot be drawn from the Funds.

At a high level, an ONFA reference plan estimates the total lifecycle costs associated with OPG's long-term nuclear liability programs and then discounts the expected stream of payments to today's dollars, representing the ONFA funding liability. This calculated liability is then compared to the present balance in the segregated Funds. Any resulting difference, or the excess of the liability over the Fund balances, is to be contributed to the Funds by OPG over the remaining life of the stations.[406] This calculation is performed as part of every new ONFA reference plan and forms the basis of OPG's contribution requirements until the next reference plan is established and approved (typically every five years).

Some of the cross-examination by SEC on the nuclear liabilities focused on gaining an understanding as to how OPG's annual cash expense with respect to its nuclear liabilities compared to what was being sought in the payment amounts.[407] This line of questioning was based on the fact that under the 2017 ONFA reference plan, OPG is not required to make any funding contribution payments to the segregated Funds over the test period (zero net contributions). This represents the first time that a reference plan did not require any contributions from OPG to either of the Funds (the Decommissioning Fund has previously been fully funded and therefore did not require contribution from OPG). To put this into perspective, between the years of 2008-2016 (nine years), OPG had contributed a total of approximately $1.992 billion to the segregated Funds for the purpose of funding its long-term nuclear liabilities (an average of approximately $221.3 million per year).[408] The 2017 ONFA reference plan does not require any contributions from OPG because the segregated Funds were determined to be in an overfunded position based on the calculation described earlier. This means that when this plan was established, the cash in the segregated Funds (market value) exceeded the ONFA funding liability.

[404] Tr Vol 20, page 105
[405] Tr Vol 20, page 104
[406] Exh C2-1-1, pages 5-6
[407] Tr Vol 21, pages 47-53
[408] Exh C2-1-2, Chart 3, page 25

In its response during the cross-examination on nuclear liabilities, OPG indicated that the amounts collected from ratepayers in a given year under the approved cost recovery methodologies cannot be compared to its annual cash expense outlay in respect to nuclear liabilities because the underlying recovery methodologies are largely based on accounting principles. The accounting tries to properly match the nuclear generation output of a given year with the total costs that are expected to be incurred as a result of that generation. These total costs for accounting purposes actually represent amounts that will be settled in cash for decades to come.[409]

OEB staff agrees that the accrual accounting based costs of nuclear generation for a given year cannot equate to the related annual cash expense outlay and therefore performing such an analysis does not provide an "apples to apples" comparison. OEB staff submits however that OPG's actual cost exposure to its long-term nuclear liabilities is ultimately determined by how much it has to contribute to the segregated Funds based on the ONFA reference plans. The lack of contributions (zero contributions) from OPG is a significant change from the previous proceedings and is a scenario that may not have been contemplated when the recovery methodologies were initially approved.

OEB staff understands that the future status of the Funds cannot be predicted with certainty since it would depend on variables such as market performance of the assets and the impact that technical innovations and efficiencies can have on the level of cost incurred. Given the complexity of nuclear liabilities, OEB staff is not advocating the use of a particular recovery method at this time, but rather is raising concerns that new risks exist that may not have been contemplated at the time the original recovery methodologies were determined. Therefore OEB staff is suggesting that a more comprehensive review of the current recovery methods is required in order to determine whether they continue to be appropriate and fair under the existing circumstances. One consideration is whether a funding-based approach is more appropriate, one that is directly correlated to OPG's level of contribution to the segregated Funds, as it will align more closely with what OPG's true cost for these liabilities will be. For example, the OEB may want to consider a recovery methodology that distinguishes between OPG's long-term and short-term nuclear liabilities. The long-term costs can be recovered in relation to OPG's contributions to the segregated Funds, and the short-term costs can be recovered in accordance with accrual accounting principles. In this manner the recovery of the long-term costs will be underpinned by OPG's legal requirements under ONFA and the related contribution payment schedules in the ONFA reference plans, and the short-term costs would be treated similarly to operating and maintenance expenses.

[409] Tr Vol 21, page 52

OEB staff submits that the OEB should require OPG, in its next cost-based nuclear payment amounts application, to provide a comprehensive study of the various cost recovery methodologies for nuclear liabilities including the provision of the underlying estimates and assumptions used. The study should also include a review of the various cost recovery methods used in other regulatory jurisdictions and whether or not these can be adopted by the OEB. OEB staff notes that although several options have been provided and reviewed for the cost recovery methodologies of nuclear liabilities since the first payments proceeding, these options were never presented in a comprehensive manner in the form of a detailed study with sufficient details and consideration of their associated strengths and weaknesses in order for the OEB to have a complete evaluation and understanding of the various recovery options on this complex issue.

8.4 Discount Rate

During cross-examination on the ONFA funding liability and OPG's asset retirement obligation (ARO), further clarification was sought in regard to why there was such a significant difference between these balances when they are largely derived from the same set of cost estimates as set out in the ONFA reference plan. The overall difference in the balances was quantified to be approximately $3.1 billion per the December 31, 2016 audited financial statements, meaning that the ARO was $3.1 billion higher than the ONFA funding liability. In its response, OPG explained that there are certain differences pertaining to the calculation of each, specifically referencing OPG's internally funded nuclear liability costs, which are included in the ARO but not in the ONFA funding liability. OPG further indicated that a portion of the difference was also attributed to the fact that the ARO and the ONFA funding liability are calculated using a different discount rate. Through undertaking J21.3, OPG was asked to quantify what portion of the overall $3.1 billion difference was as a result of the different discount rates[410] In this undertaking response, OPG prepared a reconciliation which indicated that approximately $2.2 billion of the overall difference between the ARO and the ONFA funding liability at December 31, 2016 related to the impact of using a different discount rate in the calculation of each of the balances.[411].

OEB staff notes that the discount rate used in the calculation of the ONFA funding liability represents the long-term target rate of return on the ONFA segregated Funds, which is set at 5.15%, and is prescribed by ONFA. On the other hand, the calculation of the ARO liability is dictated by the underlying accounting standards, in this case US

[410] Tr Vol 21, pages 75-80
[411] Undertaking J21.3, page 1, Chart 1

GAAP, which requires the use of a credit adjusted risk-free rate. For OPG, this rate is based on the Province of Ontario long-term bond yield rate. The overall weighted average discount rate associated with OPG's ARO is approximately 4.95%[412]

OEB staff submits that both the ARO and the ONFA funding liability represent base numbers that underpin significant portions of the overall calculation of the nuclear liability revenue requirement. Therefore for purposes of determining the payment amounts, these numbers should be calculated on a consistent basis to ensure their consistent and fair application across the revenue requirement. Based on the undertaking response noted above, OEB Staff notes that at December 31, 2016, a $2.2 billion discrepancy exists between the accounting based ARO and the ONFA derived funding liability due to different discount rates that underpin each calculation (holding all else equal). As a result, over the lifecycle of the accounting for the ARO, this "excess" amount of $2.2 billion will be recovered in the payment amounts over time through the amortization of the related asset retirement cost. From a revenue requirement perspective, this is significant because it means that ratepayers are being asked to pay for an amount that they otherwise would not have been responsible for had a different discount rate been used (or had the discount rate been aligned with the ONFA discount rate). OEB staff further notes that the calculation of other components of the nuclear liability revenue requirement may be impacted as well, such as the level of ONFA earnings that get recognized as part the Bruce nuclear liability payment amounts calculation, the level of contributions required to the segregated Funds (which are a tax deduction), and the calculation of the return on rate base (ARC) for the prescribed facilities, all of which are dependent on the balance of the ARO or ONFA funding liability.

OEB staff submits that a more thorough review of this issue should be conducted as part of the overall comprehensive study on the recovery methodologies that OEB staff has proposed in section 8.3 above.

9. DEFERRAL AND VARIANCE ACCOUNTS

9.1 Background

Issue 9.1 (Secondary) - Is the nature or type of costs recorded in the deferral and variance accounts appropriate?

[412] J21.3, p. 2, line 28. The individual discount rates associated with each of the seven tranches can also be found J21.3, Attachment 1, lines 1-7

OPG proposes to recover the audited December 31, 2015 balances in DVAs, less 2016 amortization amounts approved in EB-2014-0370, except for the Pension and 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.

The proposed clearance is $86.8 million for regulated hydroelectric facilities and $217.9 million for nuclear facilities for the January 2017 to December 2018 period. A hydroelectric payment rider of $1.44/MWh and a nuclear payment rider of $2.85/MWh are proposed to come into effect on January 1, 2017 and expire on December 31, 2018.

In OPG's settlement proposal for deferral and variance accounts, the parties settled issue 9.6 regarding the continuation of deferral and variance accounts. Partial settlement was reached for issues 9.1 regarding the nature or type of costs recorded in the deferral and variance accounts, 9.2 regarding the methodologies for recording costs in the deferral and variance accounts and 9.3 regarding the balances for recovery in each of the deferral and variance accounts. Note that issue 9.3 excluded the Pension & OPEB Cash Versus Accrual Differential Deferral Account as the account is not proposed for disposition in this proceeding. The partial settlement of these three issues excluded the Capacity Refurbishment Variance Account (CRVA) for nuclear and hydroelectric, the Nuclear Liability Deferral Account and the Bruce Lease Net Revenues Variance Account. Please see section 11.1.8 for OEB staff's submission on the hydroelectric CRVA and section 8.2 for OEB's staff submission on the Nuclear Liability Deferral Account and the Bruce Lease Net Revenues Variance Account. OEB staff's submission on issue 9.5 (is the disposition methodology appropriate?) is found in section 11.4.

9.2 Pension & OPEB Cash Versus Accrual Differential Deferral Account

OPG is not proposing to dispose the Pension & OPEB Cash Versus Accrual Differential Deferral Account (which had a balance as at December 31, 2015 of $315.2 million) in this application. Clearance of the account is subject to the results of the OEB's consultation on pension and OPEB costs (EB-2015-0040). OPG has proposed that the future consideration of recovery of the difference between cash and accrual amounts for the test period be limited to the outcome of the consultation and not be subject to a future prudence review beyond this application. OEB staff agrees with OPG's proposal in that the forecasted cash and forecasted accrual amounts for pension and OPEB costs included in this application will have gone through a prudence review and received approval as part of its total compensation levels. The Pension & OPEB Cash Versus Accrual Differential Deferral Account combined with the Pension & OPEB Cash Payment Variance Account will allow OPG to potentially recover pension and OPEB costs based on actual costs incurred under the accrual method of accounting. The amounts recorded in these accounts will need to be reviewed at the time they are requested for disposition.

OEB staff also notes that on May 18, 2017, the OEB issued its report on this consultation[413] with an opportunity for parties to comment on implementation matters. The report established the accrual method as the default rate-setting method to recover approved pension and OPEB costs, but this must be confirmed in a utility's next cost-based rate application. In addition, three of the implementation matters that are outstanding are the timing of the OEB's consideration of a utility's transition to accrual (if currently on cash), the manner in which carrying charges are applied to previously approved variance accounts and the timing of the disposition of these accounts. OEB staff makes two submissions with respect to this matter.

First, OEB staff is of the view that the account balance noted above should remain open for any adjustments that may result from the report, and for any further amounts recorded into the account during the test period.

Second, subject to the final determination of the implementation matters identified in the report, the OEB may wish to consider OPG's circumstances, including the timing of this report (and the fact that it is unknown at this time when the report will be finalized), and that it may be another five years before the OEB considers OPG's next cost-based application. OEB staff submits that the OEB's consideration of OPG's transition back to accrual and the disposition of the accounts may be considered as part of OPG's mid-term review, should the OEB approve a mid-term review as part of OPG's Custom IR plan.

9.3 Newly Requested Deferral and Variance Accounts

OPG has proposed four new accounts to be established in this application:

- the Rate Smoothing Deferral Account,
- the Mid-term Nuclear Production Variance Account,
- the Nuclear ROE Variance Account

[413] Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs

- the Hydroelectric Capital Structure Variance Account.

Please see section 11.4 for discussion of the Rate Smoothing Deferral Account and section 11.3.1 for discussion of the Mid-term Nuclear Production Variance Account.

In a response to an interrogatory[414] requesting draft accounting orders for the four new deferral and variance accounts that OPG proposes to establish, OPG indicated that it has never filed an accounting order as a part of a rate application. It has only done so as a part of an independent application. OPG did not provide a draft accounting order as requested, but provided the journal entries that would be required to record additions in the proposed accounts. OEB staff submits that OPG should provide a draft accounting order for each of the requested accounts in this application during the draft rate order process so that parties have an opportunity to comment fully on the mechanics of any accounts that may be approved by the OEB. The OEB requires electricity distributors, gas distributors and transmitters[415] that request new accounts to include a draft accounting order which must include a description of the mechanics of the account, including providing examples of general ledger entries, and the manner in which the applicant proposes to dispose of the account at the appropriate time. Whether the request for an accounting order is in a rate application or stand-alone application does not matter. OPG should adhere to this expectation in future applications.

The Nuclear ROE Variance Account is proposed to record the nuclear revenue requirement impact of the difference between the ROE approved for the nuclear business in 2018 to 2021 in this proceeding and the actual ROE as specified by the OEB that is updated annually.[416]

OEB staff notes that the proposed Nuclear ROE Variance Account appears to be inconsistent with the OEB's recently issued Handbook for Utility Rate Applications, which states:

> 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

[414] Exh L-9.8-Staff-218
[415] As noted in the OEB's Filing Requirements rate applications for electricity distributors dated July 14, 2016 (page 35), gas distributors dated Feb. 16, 2016 (page 70) and transmitters dated Feb. 11, 2016 (page 35).
[416] OPG has not proposed a corresponding deferral and variance account for the prescribed hydroelectric generation assets. Under the concept of the hydroelectric IRM "price cap" form of regulation, the inflation index (Input Price Index) implicitly includes changes in the cost of capital in the market generation over time, as the OEB has previously determined. See *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* (RP-2006-0089), December 20, 2006, pages. 29-30.

> 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. [417]

Nevertheless, OPG's application was filed prior to the issuance of the Handbook. OEB staff does not object to the proposed account.

OEB staff notes that the OEB has approved settlement agreements of certain electricity distributors[418] that included updating ROE annually based on the OEB prescribed ROE. As OPG has proposed that the ROE updates be captured in a variance account, there will not be an annual update to the application, although the proposed variance account would have the same effect.

If the OEB was inclined to grant this account, OEB staff submits that it does not take issue with the causation and prudence [419] of the proposed account. The additions proposed to the account are outside the base upon which rates were derived. The additions are incurred as a result of the ROE as set by the methodology established by the OEB in EB-2009-0084 and used to update the cost of capital parameters annually.

With respect to materiality, OEB staff notes that the OEB's ROE has fluctuated in a range of 0.58 percentage points in the last five years from 2013 to 2017. OPG indicated that a 0.1% change in the OEB's prescribed ROE in a year would have an annual impact of approximately $2.2 million and would cumulatively exceed OPG's materiality threshold over the 2017 to 2021 period.[420]

OEB staff agrees with OPG that cumulatively, over the five year term, the impact of a 0.1% change to the ROE would exceed OPG's $10 million threshold; but only by a slim margin. And as noted by OPG in response to OEB staff interrogatory #216, a 1.0% change in the OEB prescribed ROE would have an annual impact of over $20 million on OPG's nuclear revenue requirement. It is also true however, that year over year changes could offset. It is difficult to estimate the amount that would be recorded in this account as the calculation depends heavily on the percentage of ROE change in a given year as well as which year(s) the change(s) occurs in during the five year period. Therefore, OEB staff submits that the OEB could approve this account subject to the

[417] Handbook to Utility Rate Applications, October 13, 2016, page 26
[418] Horizon Utilities Corporation (EB-2014-0002), Hydro Ottawa Limited (EB-2015-0004)
[419] The three eligibility criteria are required to be met in the establishment of a new deferral and variance account and is noted for electricity distributors, gas distributors and transmitters in the OEB's Filing Requirements for rate applications for these utilities dated July 14, 2016, Feb. 16, 2017 and Feb. 11, 2016, respectively
[420] Exh L9.8-Staff-216

amounts booked in the account passing the three standard tests of causation, prudence and materiality when the account is reviewed for disposition.

The Hydroelectric Capital Structure Variance Account is proposed to record the hydroelectric revenue requirement impact of the difference between the capital structure approved by the OEB in this proceeding and the capital structure approved by the OEB in EB-2013-0321 that is underpinning the hydroelectric payment amounts in this proceeding for 2017 to 2021. In the EB-2013-0321 proceeding, OPG was approved a capital structure of 45% equity and 55% debt. In this application, OPG is proposing a capital structure of 49% equity and 51% debt. OPG is proposing that the balance in this account as at the end of 2018 be proposed for disposition during the mid-term review in 2019.

OEB staff does not take issue with the nature of this account. OPG was directed to set nuclear and hydroelectric payment amounts under two different rate-setting mechanisms, which resulted in a misalignment in the nuclear and hydroelectric cost of capital. In addition, while the methodology to the equity thickness proposal is not based on a technology-specific proposal, the fact that the OEB has considered different equity thicknesses in the past but has not approved this concept also supports the continued alignment of the two businesses with respect to capital structure.

In addition, OEB staff has no concerns with the causation, prudence and materiality[421] of the proposed account. The additions proposed to the account are outside the base upon which rates were derived. The additions are incurred to more accurately reflect the approved capital structure in the 2017 to 2021 hydroelectric payment amounts. With respect to materiality, if OPG's requested capital structure is approved, OPG will record $114.3[422] million in the variance account for the 2017 to 2021 period. If OEB staff's proposal for equity thickness is approved, OPG will record approximately $57 million in the account. In either scenario, the amounts are material both cumulatively over the term of the plan and on an annual basis.

The amount ultimately recorded in the account will vary depending on the equity thickness the OEB determines is appropriate. Therefore, OEB staff does not oppose the establishment of this variance account.

[421] The three eligibility criteria are required to be met in the establishment of a new deferral and variance account and is noted for electricity distributors, gas distributors and transmitters in the OEB's Filing Requirements for rate applications for these utilities dated July 14, 2016, Feb. 16, 2017 and Feb. 11, 2016, respectively
[422] Exh L-9.8-Staff-217

10. REPORTING AND RECORD KEEPING REQUIREMENTS

10.1 Reporting - General

Issue 10.1 (Secondary) – Are the proposed reporting and record keeping requirements appropriate?

The EB-2010-0008 decision set out financial and operating reports that OPG would file beginning in 2011.[423] Those reports are:

- Unaudited balances of deferral and variance accounts within 60 days after calendar quarter end
- The MD&A and financial statements as filed with the OSC within 60 days for the first three quarters, and within 120 days for December year-end statements as long as the OSC requires these documents to be filed
- Nuclear unit capability factors and hydroelectric availability for the regulated facilities within 60 days for the first three quarters and within 120 days for December year end as reported in OPG's quarterly and annual MD&A
- FTE information, similar to the presentation in Exhibit F4, tab 3, schedule 1, chart 1 by April 30th
- Capital in-service additions and construction work in progress by April 30th
- An analysis of the actual annual regulatory return, after tax on rate base, both dollars and percentages, for the regulated business and a comparison with the regulatory return included in the payment amounts by June 30th of each year

The EB-2010-0008 decision also noted that:

> Regular reporting of financial and operating data is an important component of the overall regulatory structure. The data allows the Board to monitor the performance of utilities in years when they are not before the Board and provides consistent data over time for purposes of various analyses. Ongoing reporting will be particularly important as OPG migrates to an IRM regime.[424]

Electricity distributors file financial and operating reports with the OEB on a regular basis in accordance with Reporting and Record Keeping Requirements (RRR) and as a condition of their licences. The current requirements include performance results for an annual scorecard that is underpinned by the Renewed Regulatory Framework (RRF). The scorecards are posted on the OEB website.

[423] EB-2010-0008, Decision with Reasons, March 10, 2011, page 150
[424] EB-2010-0008, Decision with Reasons, March 10, 2011, page 149

In the current proceeding, OPG has proposed annual filing to the OEB, additional to the EB-2010-0008 requirements, relating to DRP (section 4.3.12), hydroelectric performance (section 10.2) and nuclear filing (section 10.3). OPG states that its proposed benchmarking reporting measures are consistent with the RRF outcomes of operational effectiveness, cost performance and service quality. OPG does not have a performance measure that is analogous to the distributors' CDM targets and renewable generation connections.[425]

OEB staff has no concerns with the general structure outlined above. The Handbook for Utility Rate Applications 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 expects that OPG will supplement (or summarize) its reporting with a proposal for a detailed scorecard as part of their next cost-based application.

10.2 Hydroelectric Performance Reporting

Issue 10.2 (Primary) – Is the monitoring and reporting of performance proposed by OPG for the regulated hydroelectric facilities appropriate?

OPG proposes to file the following hydroelectric performance measures on an annual basis. These performance measures are the same as those filed with OPG's previous cost of service applications, EB-2010-0008 and EB-2013-0321. OPG proposes that the annual filing consist of the prior year's actual performance and the targets for the next year.

[425] Exh A1-3-2 page 40

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 submits that the proposed hydroelectric safety and reliability performance measures are appropriate. However, OEB staff submits that reporting the measures for a single year and the targets for the following year is not sufficiently informative. As a minimum, OEB staff submits that OPG should file the measures for the year and the targets for that year. In addition, it would be informative to provide the measures for the historical period, five years in total. This would be consistent with the Electricity Distributor Scorecards.

In cross-examination, OPG confirmed that it intended to continue to the OM&A metric that it has been using for many years.[426] The OM&A Unit Energy Cost performance measure was reviewed in the previous cost of service proceeding, EB-2013-0321. OEB staff and several parties commented on the limited scope of the OM&A costs reviewed.

At the technical conference for the current proceeding, OPG confirmed that lines 3 and 4 of the table below (from EB-2013-0321) are not included in the proposed cost effectiveness metric.[427] Further, during the oral hearing, OPG confirmed that it does not propose to provide any quartile analysis for the OM&A Unit Energy Cost.

[426] Tr Vol 9 page 88
[427] Technical Conference Tr November 15, 2016 page 212

Table 36

OperatingCostsSummary-PreviouslyRegulatedHydroelectric($M)

Line No.	Cost Item	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
	OM&A:						
1	**Base OM&A[1]**	59.4	50.1	60.2	61.6	74.6	68.6
2	**Project OM&A**	5.4	6.6	13.6	14.7	13.5	17.9
3	**Allocation of Corporate Costs**	22.4	22.0	24.5	26.1	29.8	26.9
4	**Allocation of Centrally Held Costs**	19.6	15.9	19.6	20.7	26.1	26.0
5	**Asset Service Fee**	2.1	1.6	1.8	1.6	1.5	1.7
6	**Total OM&A**	108.8	96.3	119.7	124.7	145.5	141.1
7	**Gross Revenue Charge**	252.2	259.4	244.5	249.5	253.3	269.5
	Other Operating Cost Items:						
8	**Depreciation and Amortization[2]**	63.5	65.6	70.0	80.5	82.1	81.9
9	**Income Tax**	29.9	33.4	32.3	(0.1)	48.5	61.5
10	**Capital Tax**	2.8	N/A	N/A	N/A	N/A	N/A
11	**Property Tax**	0.1	0.2	0.2	0.2	0.3	0.3
12	**Total Operating Costs**	457.4	454.9	466.6	454.7	529.5	554.4

On December 20, 2016, OPG filed the first impact statement, Exh N1-1-1. That impact statement included the 2017-2019 Business Plan. The business plan states, “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.”[428]

In cross-examination, OPG confirmed that the hydroelectric TGC was an “all-in number”, including GRC.[429] OPG noted that the TGC is a new metric for OPG and that the metric is determined on a total business basis, i.e., there is no TGC determination by each of the regulated hydroelectric and unregulated hydroelectric businesses.

OPG determines nuclear performance annually and this includes benchmark quartile analysis for all aspects of the reporting, including costs. OEB staff submits that OPG’s regulated hydroelectric business should move towards this type of reporting and monitoring as well.

As a minimum, OEB staff submits that OPG should report OM&A Unit Energy Cost and TGC for the regulated hydroelectric business in the test period. This would be consistent with the business unit reporting that OPG will be producing internally. The filing should include the measures for the year and the targets for that year. As noted for

[428] Exh N1-1-1 Attachment 1 page 4
[429] Tr Vol 9 page 90.

safety and reliability measures, in addition, it would be informative to provide the measures for the historical period, five years in total.

10.3 Nuclear Performance Reporting

Issue 10.3 (Primary) – Is the monitoring and reporting of performance proposed by OPG for the nuclear facilities appropriate?

OPG proposes to file the following nuclear performance measures on an annual basis.[430] The 20 performance measures are the same as those used in the annual benchmarking reports filed in cost of service proceedings. OPG proposes that the annual filing consist of the prior year's actual performance and the targets for the next year.

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)

[430] Exh A1-3-2 page 42

In cross-examination by OEB staff, the proposed filing and the annual nuclear benchmarking report were compared.[431] OEB staff's summary of the annual benchmarking report is in section 6.2 of this submission. In response to cross-examination, OPG stated that it did not object to filing annual reports that provided further detail than proposed. That detailed reporting included:

- Quartile benchmarking
- OPG nuclear performance on TGC, NPI and UCF
- Normalized and non-normalized performance
- Performance metrics for the year and targets for that year

OPG noted that benchmark data could only be provided later in the year, but agreed to provide raw data earlier in the year.

OEB staff submits that it would be informative to provide the measures for the historical period, five years in total. This would be consistent with the Electricity Distributor Scorecards.

11. METHODOLOGIES FOR SETTING PAYMENT AMOUNTS

11.1 Hydroelectric Payment Amount Setting

Issue 11.1 (Oral Hearing) – Is OPG's approach to incentive rate-setting for establishing the regulated hydroelectric payment amounts appropriate?
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?
Issue 11.7 (Primary) – Is OPG's proposed off-ramp appropriate?

11.1.1 Background

In its application, OPG has filed the first ever proposal for a five-year hydroelectric Incentive Rate-setting Mechanism (IRM) plan. Under this plan, hydroelectric payments would be adjusted annually by an inflation less expected productivity improvements (I – X) formula:

$$P_t = P_{t-1} \times \left(1 + (I_t - X \pm Z)\right)$$

431 Tr Vol 6 pages 143-147

Where P_t is the price (hydroelectric payment amount) at time t, I_t is the inflation measured at time t, X is the expected productivity target, consisting of a base X and a stretch factor, and Z is a factor for exogenous events that may require accommodation for recovery, but which are beyond OPG's ability to predict or control for the most part. This form of IRM plan is called a price cap, as price increases are capped by the I – X formula over the term of the plan.

This is a common form of IRM plan, and has been the standard form of IRM mechanism adopted by the OEB in IRM rate regulation of electric and natural gas distributors. OPG's proposal is very closely derived from the (current) Price Cap IR plan for electricity distributors in Ontario (per the Report of the Board EB-2010-0379).

While this is the general design of the plan, there are some additional elements, which OPG has documented in the evidence and where Chart 1[432] provides a useful summary of the various factors as OPG has proposed them, along with the analogous measures of the Price Cap IR plan for electricity distributors.

OEB staff does not take issue with the following items listed in Chart 1 as they are part of the established Price Cap IR methodology that the OEB applies to electricity distributors:

- "Going-in" rates
- Price cap form of payment adjustment
- Comprehensive (Capital and OM&A) IRM plan
- 5-year term of IRM plan (2017 to 2021)
- Incremental Capital Module
- Treatment of unforeseen events – Z-factor
- Sharing of Benefits – no Earnings Sharing Mechanism
- Treatment of Deferral and Variance Accounts, with the exception of the CRVA under the hydroelectric IRM plan

OEB staff deals with Performance Reporting and Monitoring in section 10.2. Off-ramps are discussed in section 11.2.

OEB staff makes additional submissions on the following elements:

[432] Exh A1-3-2 pages 6-7

- Formulation of the Inflation Factor (the Input Price Index or IPI), including the Treatment of Gross Revenue Charge
- Calculation of the 2017 IPI
- The base X-factor as derived from a historical TFP study
- The stretch factor
- The treatment of the CRVA

11.1.2 Formulation of the IPI

OPG has proposed a 2-factor IPI, composed of labour and non-labour components:

- Input price inflation for labour would be represented by the annual percentage change of the most recent historical calendar year published by Statistics Canada for the Average Weekly Earnings (AWE), including overtime, for Ontario and all business categories excluding unclassified, compared to the immediately preceding historical year
- Input price inflation for non-labour (capital and materials) would be represented by the Implicit Price Index for national Gross Domestic Product (Final Domestic Demand) [GDP-IPI (FDD)] for the most recent historical calendar published by Statistics Canada, compared to the immediately preceding historical year.

These are the same data that are used for electricity distributors under Price Cap IR. OPG, based on London Economics International. (LEI's) analysis, proposed different weights for the labour and non-labour components than are used for electricity distributors. Specifically, it has proposed a labour weight of 12% and a non-labour weight of 88%, representing the fact that its hydroelectric generation business is heavily capital-intensive, and with much less labour, particularly reflecting technological improvements for hydroelectric dams and generators once constructed and in operation.

OEB staff considers that, subject to comments below regarding the treatment of the Gross Revenue Charge, OPG's proposed methodology is reasonable. The changes to weights are appropriate given the proportion of inputs that labour and non-labour components represent, and reliance on the same Statistics Canada data for the inflation indices of labour and non-labour eases transparency, understanding, and ease of calculation of the measure. OEB staff also discusses issues regarding the exact calculation for the 2017 IPI later in this submission.

11.1.3 Treatment of Gross Revenue Charge

During cross-examination, SEC questioned OPG regarding the treatment of the Gross Revenue Charge (GRC) in the construction of the IPI.[433,434] GRC costs are not subject to inflation. Variability in GRC from one rate period to another is solely due to volume variation. Further, GRC constitutes a significant portion of the hydroelectric revenue requirement, approximately 27%.

SEC's point was that GRC, as a material fraction of the revenue requirement, has a 0% annual inflation growth rate, so that the two-factor (labour and non-labour (capital and materials)) IPI would overstate the inflation drivers of hydroelectric payments.

OEB staff concurs with SEC that few businesses or industries would have as great a proportion of costs that are essentially "inflation-less", but it is not to say that "inflation-less" costs do not occur in other businesses. Payments for land or water rights that natural resource firms (mining or forestry) or water bottlers pay may also not be subject to inflation.

Further, the non-labour component of the IPI is GDP-IPI. This is the implicit price deflation of GDP, which is a measure of output. However, it is commonly used as a proxy for input price inflation, and for two reasons:

1. There are few, if any, good direct measures of inflation in business prices on a macroeconomic scale.
2. There are many outputs of one firm or sector which serve as inputs for another firm. In the case of OPG, it relies on the outputs of firms for steel, concrete, vehicles, turbines, copper, computer hardware and software, etc. as "inputs" for hydroelectric generation.

[433] Tr Vol 10 pages 79-84 and 89-95
[434] The hydroelectric operating costs include the GRC, which is governed by legislation and refers to taxes and charges that are required to be paid by owners of hydroelectric generating stations. The GRC consists of a property tax component and a water rental component and is a significant component of total operating costs.

Details pertaining to GRC are noted under Section 92.1 of the Electricity Act, 1998 and Ontario Regulation 124/02, and are unchanged from the 2011-2012 payment amounts proceeding, EB-2010-0008. As noted in the EB-2013-0321 proceeding: previously regulated hydroelectric GRC was forecast to be $267.3M in 2014 and $280.8M in 2015. The newly regulated hydroelectric GRC was forecast to be $75.6M in 2014 and $77.5M in 2015.

Thus, output price inflation, such as is represented by GDP-IPI, is an accepted proxy for input price inflation.[435]

OEB staff has no reason to believe that “inflation-less” costs are not appropriately reflected in a well-established Government-published statistic such as GDP-IPI, but does accept that OPG’s situation is significantly different from most firms and business sectors.

OEB staff submits that a reasonable approach would be not to use the whole weight of GRC (about 25% of the hydroelectric revenue requirement),[436] as some portion of “inflation-less” costs for all businesses is likely factored into the GDP-IPI. A compromise would be to use half of the weight, so that the IPI would become a 3-factor IPI composed as follows:

- Labour – 12% weight as proposed by OPG, using the annual percentage change in Ontario Average Weekly Earnings (including overtime)
- Non-Labour (capital and materials) – 75.5% weight, using the annual percentage change in GDP-IPI (FDD)
- GRC – 12.5% weight, using a 0% (“inflation-less”) growth rate

Using the methodology that OEB staff has documented in Exh L-11.1-Staff-227 and Exh K9.1, this would give a 2017 IPI of 1.5%, as shown in the following Table. This is in contrast to a 2017 IPI of 1.3% if the full GRC weight of 25%, as suggested by SEC during cross-examination, was used (and as opposed to the 1.8% IPI proposed by OPG).

[435] And is generally advantageous to a consumer-based measure of inflation such as the Consumer Price Index (CPI), which does not correspond to the kind and mix of capital and expensed costs that businesses rely on as inputs to production. This particularly holds for network infrastructure businesses, such as gas distributors and electricity transmitters, distributors and generators, which are all capital-intensive.
[436] Tr Vol 10 page 80.

Table 37
2017 IPI Calculation per OEB Methodology
(with half of GRC revenue requirement (12.5%) subject to 0% inflation)

GRC inflation set to 0% (12.5% of hydroelectric revenue requirement)

	Inputs and Assumptions													
Year	Non-Labour GDP-IPI (FDD) - National							Labour AWE - All Employees - Ontario			GRC		Resultant Values - Annual Growth for the 2-factor IPI based on OPG's	
	Q1	Q2	Q3	Q4	Annual	Annual % Change	Weight	Annual	Annual % Change	Weight	Inflation	Weight	Annual	Annual % Change
2014	112 5	113 2	113.7	114.1	113.375			$ 938.27					103.7	
2015	114.4	114 8	115.6	116.1	115.225	1.619%	75.5%	$ 962.73	2.574%	12%	0%	12.5%	105.2997	1.5309%
							1.220%			0.310%				1.53%
														1.50%

In OEB staff's submission, this would be a preferred approach for calculating the IPI and reflecting the significant proportion of the hydroelectric revenue requirement represented by the "inflation-less" GRC costs, beyond what is already reflected in the GDP-IPI for "inflation-less" costs generally in the economy.

OEB staff also notes that the OEB has taken a similar approach to its estimation of the impacts of annual general tax changes reflected in the IPI as it applies to gas and electricity distributors. The exact impact of general tax changes is not known but it is accepted that the applicable indices do reflect some changes in economic output due to taxes as well as other components such as the cost of capital. The OEB's approach to this uncertainty was to assume a 50/50 split between what is subsumed in the annual IPI for tax changes and what should be deemed as an incremental adjustment to base rates.[437] OEB staff suggests that a similar approach with respect to the assumptions used to determine the portion of "inflation-less" GRC costs can be made.

11.1.4 Calculation of the 2017 IPI

Using the proposed IPI formula LEI, on behalf of OPG, calculated a value of 1.8% for the IPI for 2017, based on 2015 annual data available at the time that OPG filed its application.[438] Through an interrogatory, OEB staff asked OPG to confirm that the IPI for 2017, based on annual data as of the StatsCan's 2016 Q2 data release at the end of August 2016 was 1.7%.[439] This StatsCan release is used for rate decisions for the next

[437] Decision EB-2007-0606/0615, July 31, 2008, pages 8-9, *Supplemental Report of the Board on on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*, September 17, 2008, page 35.
[438] Exh A1-3-2 pages 11-15, section 2.3.1
[439] Exh L-11.1-Staff-227

calendar year, and this approach has been used for calculating the IPI for electricity distributors since the issuance of the Report of the Board in EB-2010-0379.

While agreeing generally with the approach, OPG disagreed with staff's calculation and submitted that the 2017 IPI calculation remained at 1.8%.[440] OPG was further questioned during the oral hearing about this, and with respect to the differences between OEB staff's calculations and those done by OPG.[441] The differences boil down to two factors, based on OEB staff's analysis shown in Exh K9.1:

1. Use of the natural logarithmic (ln) function instead of the arithmetic formula to calculate annual growth rates
2. Use of rounding for intermediate calculations as opposed to rounding final numbers only

While acknowledging the differences, OPG submitted that they were alternative approaches but that its approach was consistent with the RRFE, referencing the source for its approach as "Appendix B" of an OEB document issued on October 4, 2012.[442]

OEB staff submits that OPG is incorrect. The RRFE Report was issued on October 18, 2012, and Appendix B of that report is a "Summary of Planned Consultations".[443] The only OEB "document" issued on October 4, 2012, was the IPI for 2013 under the then-current 3rd Generation IRM, which is unrelated to the RRFE. At that time, the IPI was a single factor inflation index, using only GDP-IPI (FDD) for input price inflation. The arithmetic approach to calculating the annual growth rate was used consistent with StatsCan's own methodology for published statistics such as the GDP-IPI. There was no rounding until the final stage, although this was not material.

The two-factor IPI for electricity distributors that forms the starting point for OPG's proposal was not issued until November 21, 2013 (updated December 4, 2013), when it was documented in the *Report of the Board on Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors* (EB-2010-0379). The methodology was described in section 2.1 of that report, and the calculation was shown for historical periods in Appendix B and for the 2014 IPI in Appendix C. The change to the natural log function for calculating the annual growth rate was made at that time, although it would not be apparent in the

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[440] Technical Conference Tr Vol 2 pages 200-203
[441] Tr Vol 9 pages 32-37
[442] Tr Vol 9 page 35
[443] *Report of the Board on the Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, October 18, 2012

document.[444] However, this change was done because Pacific Economics Group (PEG) used the same two-factor IPI as a price deflator in its TFP analysis of Ontario electricity distributors for setting the base X-factor in the new Price Cap IR (originally referred to as 4th Generation IRM). PEG used the natural log function in the calculation of the IPI for use in the historical TFP analysis; it made sense to remain consistent in calculating the two-factor IPI the same way going forward for the price cap rate adjustments.

As LEI has acknowledged, the use of the natural log function for calculating the annual growth rate is a common and valid econometric technique and used by LEI in its analysis.[445] PEG also used the same approach. As LEI has pointed out, the use of the natural log function for growth rates introduces no material or systematic bias.

The use of rounding for intermediate calculation is also unnecessary. Neither LEI nor PEG use it in their TFP models,[446] and even OPG does not use rounding in its Revenue Requirement Work Form.[447]

OEB staff submits that, subject to the discussion on the GRC above, the two-factor IPI as calculated by OEB staff in Exh L-11.1-Staff-227 and in the table in Version 1 of Exh K9.1 should be used. Adoption of the same methodology would facilitate calculation of the IPI for OPG's hydroelectric Price Cap adjustment based on the same data and approach as is used for electricity distributors, a concept that OPG has agreed as being efficient.[448] This would result in an IPI of 1.7% for 2017. Further, this same methodology for calculating the IPI for OPG's hydroelectric payment price cap adjustment should also be used for the remaining years (i.e., 2018 through 2021) of the IRM plan.

11.1.5 Base X-factor and TFP Analysis

The first aspect of developing the X-factor is to look at the level of productivity expected from the sector, and is based on observed actual productivity performance. A Total Factor Productivity (TFP) study is the common, and most preferred, approach to estimating the X-factor. A TFP study is a detailed econometric model that examines the rate of change of outputs (the products and services produced by the sector or firms in it) relative to the rate of change of inputs (inputs to production, typically categorized as

[444] While the exact methodology is not shown in the static PDF report, the methodology for calculating the IPI would have been in worksheet models used by PEG in that consultative process.
[445] Tr Vol 9 pages 36-37
[446] For LEI, the excel version of their models are filed in Exh L-11.1-Staff-246, while PEG's model is filed in response to Exh-M2-11.1-OPG-1.
[447] Exh N3-1-1 Attachment 3
[448] Exh L-11.1-Staff-227 a), Technical Conference Tr Vol 2 pages 202-203

labour, material and capital (assets and equipment) used in producing the products and services).

OPG retained LEI to perform a TFP analysis based on a sample of firms, including OPG and a sample of U.S. utilities with significant nuclear and hydroelectric generation. LEI's report is provided in Exh A1-3-2 Attachment 1. LEI calculated a historical TFP of -1.01% per annum; OPG proposed a base X-factor of 0%, largely on the basis that the OEB has not accepted a negative X-factor in any previous IRM plans.

OEB staff retained PEG to review OPG's hydroelectric IRM proposal and LEI's TFP study and to conduct an independent study, as necessary. PEG's review and independent TFP study is documented in Exh M2.

PEG used an alternative specification for its TFP analysis, and used financial data as opposed to the physical quantity method employed by LEI. PEG also used a slightly different time period. PEG summarized the differences and similarities with LEI's analysis in the Examination in Chief.[449] LEI also provided a similar comparison during its Examination-in-Chief.[450] The chief attributes are summarized in the following table:

Table 38
Summary of Methodologies (LEI and PEG)

	LEI's Methodology	PEG's Methodology
Approach	Index-based TFP	Index-based TFP
Output Measure	MWh (production)	MW (capacity)
Capital Measure	Physical capacity (MW)	Monetary measure of capital assets
Depreciation	No depreciation assumed for physical assets (analogous to "one hoss shay" depreciation)	Geometric depreciation
Operating costs	Monetary	Monetary
Sample	Sample of U.S. firms and OPG	Sample of U.S. firms
Study period	2002 to 2014	1996 to 2014
Outcome	-1.01% annual TFP for sample	+0.29% annual TFP for sample

449 Tr Vol 11 pages 7-17
450 Tr Vol 9 pages 18-30

PEG estimated a historical TFP of 0.29% for its sample over the period 2002-2014. To this would be added the stretch factor of 0.3% (see section 11.1.6), resulting in a total X-factor (i.e. X-factor plus stretch factor) of 0.59% for OPG's price cap formula.

OEB staff supports PEG's analysis and its estimate of a base X-factor of 0.29%. As PEG noted in its evidence and testimony the monetary approach used is more common, particularly in North America. The OEB has only relied on the results of TFP studies using financial methods, and did not adopt LEI's physical approach that was filed in the consultative process that resulted in the 3rd Generation IRM plan for electricity distributors.[451] PEG explained that the physical method is commonly used where financial data is not available or not of adequate quality.[452] Under cross-examination, PEG acknowledged that the Australian Energy Regulator (AER) adopted an X-factor that was influenced by a physical data-based study, as opposed to a financial data-based approach used by PEG. PEG explained that the AER had concerns about the availability and quality of financial data.[453] OEB staff submits that PEG's explanations are corroborated by the following excerpt from the AER's report which is found in this proceeding on page 13 of Exh K11.3:

> In relation the possible use of alternative capital input methodologies, we consider RAB [Regulatory Asset Base = rate base] depreciation may be a useful starting point for measuring the annual capital input.[footnote omitted] Economic Insights considered RAB depreciation could produce a series similar to a one hoss shay proxy in principle, but that it also identified the issues raised in submisslons and recommended further investigating using RAB depreciation.[footnote omitted]
> We consider the RAB straight line depreciation proxy may provide a similar result to the one hoss shay physical capital measure in principle. Further, the depreciated RAB proxy is relatively simple to calculate. However, in practice these two methods may not produce results that are consistent with the use of physical capital measures. We agree with Economic Insight's recommendation that these two proxies warrant further investigation.

OEB staff does not support LEI's TFP study nor OPG's proposed base X-factor of 0%. LEI's study estimates a long-run TFP of -1% for OPG and a sample of comparator firms. LEI's approach uses a physical measurement of capital, in contrast to the monetary approach employed by PEG. LEI's physical approach is similar to a monetary approach using a "one hoss shay" depreciation profile, whereby it is assumed that there is no depreciation in the utility of an asset until it reaches end-of-life, at which time total failure occurs.

[451] *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* (EB-2007-0673), September 17, 2008, pages 11-12.
[452] Tr Vol 11 pages 96-97, page 99
[453] Exh K11.3 page 12.

A standard incandescent light bulb is often used as a simple example of this type of asset that works from the start and has no (or very little) decline in its utility until it fails completely. However, a hydroelectric generating station is a very different beast, both in terms of size, cost and complexity, as was pointed out by PEG.[454]

A physical approach was also used by LEI, engaged by a coalition of distributors, for a similar productivity analysis in conjunction with the consultative process to develop the 3rd Generation IRM plan. As has been pointed out, the OEB did not accept the physical approach there, but relied on the results advanced by PEG and other experts based on monetary approaches.[455]

Further, as PEG pointed out, even if a single hydroelectric generating station follows a “one hoss shay” depreciation schedule, the “one hoss shay” approach only applies to a portfolio of generating stations if all follow exactly the same ”one hoss shay” and for the same useful economic life. This is unlikely for a large number of hydroelectric stations built at different times, using different technologies available at the time of construction and subsequently for periodic refurbishment, and built and operated under different conditions. As has been pointed out, some generating facilities are over a century old, while some are newer. Further, even OPG has an example of one station – Big Chute – which was rebuilt in 1993 after its initial construction in the 1909-1919 period.[456]

PEG pointed out during cross-examination that a portfolio of assets that have different lives, even if individually they follow the “one hoss shay” approach, will deviate from this, and sometimes substantially.[457] All econometric models are simplifications of the real world phenomena that we wish to understand, but in this case, the monetary method is better at accommodating real world factors such as the complexity of hydroelectric generating plants and associated assets.

OEB staff also considers that there is another shortcoming of LEI’s approach. While the amount generated (i.e., MWh) is the ideal output measure in theory, we are generally faced with another problem. There is an additional input – water power – for which good data on the quantity and on the “price” is not readily available. Water (either in flowing from a higher point to a lower point (e.g., Niagara Falls) or as a river or tidal flow of water, is the “fuel” that powers the turbines at hydroelectric generating stations. Water

[454] Tr Vol. 11, pages. 9-14.
[455] Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario’s Electricity Distributors (EB-2007-0673), September 17, 2008, pages 10-13.
[456] Exh A1-4-2 page 2 Chart 1
[457] Tr Vol 11 page 84. This is also made in a quote from another paper at the top of page 27 of Exh K11.3, taken from a paper on TFP filed by another PEG consultant in a proceeding down in Australia.

flow may or may not be measured; more importantly for econometric analyses such as TFP, the “cost” of water is not well defined. And it is evident from the record, both for OPG and for other hydroelectric generating utilities used in LEI’s and PEG’s samples, that hydroelectric generating stations do not run flat out all of the time, both because of hydrological considerations but also because demand for electricity fluctuates depending on day and hour and weather considerations.

In essence, LEI’s approach is more akin to a partial factor productivity approach, in that one significant input is missing which can have a significant impact on the results. OEB staff submits that it is the omission of water (i.e., hydrology) which has contributed to the -1.01% TFP result of LEI’s study. That the result may be negative may in part be due to the drought conditions in the latter part of the sample time period, and which affected the production of some of utilities in LEI’s sample from the southwestern United States and on which LEI was cross-examined by OEB staff.[458] However, OPG has not been affected to the same extent by volatile hydrological situations, not does it expect any significant variation of these during the IRM plan period.[459]

In the absence of data on which to model water conditions and costs, the best alternative is to model capacity (MW), as PEG did.[460] While not ideal, the presumption is that the firm will build and operate stations appropriate for the conditions (i.e., size of water source, other geological factors) to meet demand and to take best advantage of variability of water flow to “fuel” generation, for which the utility may have only limited control over the water conditions.

OPG should be given credit for proposing a base X-factor of 0%, from the starting point of LEI’s study estimate of -1%. That said, OEB staff considers a 0% X-factor as not being realistic either. OPG does maintain and refurbish its hydroelectric generating plants on a routine basis. Improvements in technology for both capital assets and operating activities (e.g., such as remote monitoring and control) are ways that OPG has and should continue to improve operations. Now with the Niagara Tunnel completed and in service, OPG is entering a more stable environment, which should facilitate OPG’s opportunities to innovate and to realize gains that will benefit OPG, its shareholder and also Ontario electricity consumers.

OEB staff considers that PEG’s estimate of a +0.29% base X-factor from its study is more reasonable and is, in the end, based on a sounder methodology. As a result, OEB

[458] Tr Vol 9 pages 53-59
[459] Exh A1-3-2 Attachment 1 page 19 Figure 8, Tr Vol 10 pages. 52-53
[460] Tr., Vol. 11 (March 23, 2017), p. 31/ll. 1-15.

staff submits that the base X-factor should be 0.29% for the term of this first ever IR period.

11.1.6 The Stretch Factor

The stretch factor is a separate adjustment added on to the base X-factor to reflect what is believed to be additional opportunities and incentives to increase productivity beyond what the firm and the sector have been able to realize in the past. The general premise is that, by "loosening" the relationship between costs and revenues under IRM, relative to traditional cost of service rate-setting – and in particular not tying rates to a specific budget of capital and operating plans and costs – the firm has more flexibility to adjust cost outlays to changes in demand and other operating and environmental parameters, and to take advantages of opportunities for cost efficiencies.

The stretch factor is set separately from the base X-factor. There is no standard methodology for establishing a stretch factor, and it is generally set based on informed and qualitative judgement of what should be feasible and reasonable.

OPG has proposed a stretch-factor of 0.3%. This is based on two components:

1. The results of the Navigant benchmarking study that OPG commissioned (as a result of OEB direction in the EB-2013-0321 decision)
2. The approach used in the Price Cap IR for electricity distributors, whereby each utility's stretch factor is set annually based on an updated econometric benchmarking analysis to assess its performance relative to where it should be, based on its operational characteristics, and performance of other firms in the sector.

Navigant's study is classified as a partial cost function approach.[461] This refers not only to the fact that not all costs were employed in the analysis, but also, in OEB staff's view, that most of the comparisons presented were on specific cost categories without controlling for all other elements.[462] OEB staff makes its submissions on the hydroelectric benchmarking in section 11.1.9, but for purposes of the stretch factor, OEB staff notes that this is the best information available of the record.

[461] Exh L-11.1-Staff-229
[462] As a hypothetical example, a firm that has reduced its expensed labour through substitution by capital may show improved performance on labour productivity, but this hides the fact that capital expenditures have increased and overall productivity may have increased, decreased or remained unchanged.

Navigant's results show that, in general, OPG's performance relative to the comparator group would put it around the middle of the pack.

Based on this, OPG has proposed to also use the median stretch factor of 0.3% as is used for electricity distributors.

During the Technical Conference, OPG noted that, based on a Total Cost Approach from the Navigant study, OPG would be scored a stretch factor of 0.45% (i.e., worse than average performance).[463] However, OEB staff considers that the partial cost function benchmarking analysis (i.e., by individual cost categories) of the Navigant study is more complete given the data and other limitations of the study, and takes no issue with OPG's proposed stretch factor of 0.3%. OEB staff's expert, PEG, also reached the same conclusion.[464]

OPG has proposed that the stretch factor be fixed for the five-year term of the plan. OEB staff notes that OPG is unique in Ontario, as it is the only rate-regulated generator. Also, its prescribed hydroelectric generation facilities constitute the majority of total hydroelectric generation in Ontario. As has been discussed both with respect to benchmarking and TFP analyses, it is also difficult to obtain complete and comparable statistics on hydroelectric generation for utilities in most other provinces, due to their structure, government ownership and different regulatory frameworks that they operate under. Similarly, most generators in the United States (and elsewhere in the world) operate with different sizes, ownership, and business models and regulatory frameworks, such that obtaining comparable data is difficult.

In such circumstances, it would be difficult to do annual benchmarking to determine how OPG is performing relative to a set of comparable firms and thus adjust the stretch factor for each annual IRM rate adjustment as is done for Ontario electricity distributors. Assuming the fixed 0.3% is probably the best that can be done for now. Improvements in benchmarking should still be explored by OPG, as is discussed elsewhere in this submission.

OEB staff believes that the base X-factor of 0.29% as calculated by PEG in its analysis, combined with a stretch factor of 0.3%, will suitably incentivize OPG to strive for improved performance in hydroelectric generation, have a reasonable opportunity to realize and even exceed this during a stable operating environment, and to ensure a sharing of the benefits between OPG and its shareholder, on the one hand, and Ontario

[463] Exh L-11.1-CME-6, Technical Conference Tr Vol 2 pages 165-166
[464] Exh M2 pages 60-61

electricity users, on the other. OEB staff notes that this is what is ideally desired as an outcome for the design of an IRM plan.

11.1.7 Summary of Impacts of OEB Staff Submission

The following table summarizes hydroelectric payment amounts and revenues under:

1. OPG's proposal: 2017 IPI of 1.8%, X-factor of 0%, stretch factor of 0.3%
2. OEB staff's submission with respect to calculation of the IPI (1.7% for 2017), X-factor of 0.29% and stretch factor of 0.3%
3. OEB staff's submission as above, but with a 12.5% weighting for GRC with 0% inflation (i.e., 2017 IPI of 1.5%)

Table 39

1 ***OPG's Proposal***

2017 IPI	1.80%
X-factor	0.00%
Stretch factor	0.30%
Price Cap Index (PCI)	1.50%

		2016	2017	2018	2019	2020	2021
Price Index		100	101.5	103.02	104.57	106.14	107.73
Hydroelectric Payment Amount	$/MWh	"going-in" Rate 41.09	41.71	42.34	42.98	43.62	44.27
Source: Exh. I1/2/1/Table 1a							
Annual Production Forecast	TWh	32.98	32.98	32.98	32.98	32.98	32.98
Source: N3/1/1/Attachment 1/Sheet 11/Cell J49							
Hydroelectric Revenues		$ 1,355,148,200	$ 1,375,595,800	$ 1,396,373,200	$ 1,417,480,400	$ 1,438,587,600	$ 1,460,024,600

2 ***OEB IPI calculation methodology, PEG's estimate of X = 0.29%, stretch-factor = 0.3%***

2017 IPI	1.70%
X-factor	0.29%
Stretch factor	0.30%
Price Cap Index (PCI)	1.11%

		2016	2017	2018	2019	2020	2021
Price Index		100	101.11	102.23	103.36	104.51	105.67
Hydroelectric Payment Amount	$/MWh	"going-in" Rate 41.09	41.55	42.01	42.48	42.95	43.43
Annual Production Forecast	TWh	32.98	32.98	32.98	32.98	32.98	32.98
Hydroelectric Revenues		$ 1,355,148,200	$ 1,370,319,000	$ 1,385,489,800	$ 1,400,990,400	$ 1,416,491,000	$ 1,432,321,400

Difference from OPG proposal

		2017	2018	2019	2020	2021
Payment amounts	$/MWh	-0.16	-0.33	-0.50	-0.67	-0.84
Hydroelectric Revenues		-$ 5,276,800	-$ 10,883,400	-$ 16,490,000	-$ 22,096,600	-$ 27,703,200

3 ***OEB staff's submission as 2 above, but with a 12.5% weighting for GRC with 0% inflation (i.e., 2017 IPI of 1.5%)***

2017 IPI	1.50%
X-factor	0%
Stretch factor	0.30%
Price Cap Index (PCI)	0.91%

		2016	2017	2018	2019	2020	2021
Price Index		100	100.91	101.83	102.76	103.7	104.64
Hydroelectric Payment Amount	$/MWh	"going-in" Rate 41.09	41.46	41.84	42.22	42.6	42.99
Annual Production Forecast	TWh	32.98	32.98	32.98	32.98	32.98	32.98
Hydroelectric Revenues		$ 1,355,148,200	$ 1,367,350,800	$ 1,379,883,200	$ 1,392,415,600	$ 1,404,948,000	$ 1,417,810,200

Difference from OPG proposal

		2017	2018	2019	2020	2021
Payment amounts	$/MWh	-0.25	-0 5	-0.76	-1.02	-1.28
Hydroelectric Revenues		-$ 8,245,000	-$ 16,490,000	-$ 25,064,800	-$ 33,639,600	-$ 42,214,400

11.1.8 Operation of the CRVA under Hydroelectric IRM

Background

The Capacity Refurbishment Variance Account (CRVA) was established in conformance with section 6(2)4 of O. Reg. 53/05.[465] As noted in the evidence of the first payment amounts proceeding[466], the CRVA was established for the interim period (i.e. April 1, 2005 to the date of the OEB's first order) to record costs to increase output of, refurbish or add capacity. In the EB-2007-0905 decision, the OEB approved the continuation of the CRVA.[467] The account applies to both nuclear and regulated hydroelectric generation assets, and the regulation was amended in 2015 to specifically include costs related to the DRP. This submission focuses on OPG's proposal for the hydroelectric CRVA under the hydroelectric IRM.

The continued use of the CRVA has been approved by the OEB in previous payment amount applications to allow for recovery of prudently incurred costs to enhance or expand capacity or to refurbish existing facilities to maintain capacity. No more, no less. OPG confirmed that this is the intention of the CRVA.[468]

Operation of the CRVA is relatively straightforward under traditional (annual) cost of service, where the costs and revenues are exactly known. However, the situation becomes more complicated under IRM. OPG has claimed that the IRM mechanism decouples revenues and costs.[469] However, OEB staff submits that the IRM mechanism only loosens the linkage between costs and revenues. The existence of many DVAs for OPG that deal with costs and revenues is a clear demonstration that there is not a complete "decoupling" of costs and revenues, even under IRM. Further, the existence of these DVAs reduces the "power" of IRM in terms of incentivizing OPG to reduce costs. It does not eliminate these incentives entirely, but it does compress the gap from the traditional cost of service approach in terms of providing adequate incentives for efficiency gains.

OPG's original proposal for variances to be recorded in the CRVA compared actual CRVA in-service additions to a "reference" amount, the average approved annual revenue requirement amount corresponding to CRVA-qualifying projects for 2014-2015

[465] O.Reg. 53/05 s. 6(2)4. See also Exh H1-1-1 pages 12-14
[466] EB-2007-0905, Exh J1-1-1 page 7
[467] Decision with Reasons, EB-2007-0905, November 3, 2008, page 122
[468] Tr Vol 20, pages 68-69, Tr Vol 21 pages 24-25
[469] Exh L-11.1-SEC-95.

that was factored into the hydroelectric payment amounts in EB-2013-0321. The $0.9 million reference amount would be held unchanged throughout the 2017 to 2021 period, as proposed in OPG's original application.[470]

During the course of the proceeding, one issue that emerged was the potential of double-recovery of the CRVA – hydroelectric under an IRM. As requested by the OEB,[471] OPG subsequently amended its evidence on how the hydroelectric CRVA would work and filed Exh H1-1-2 on April 4, 2017. With the amendment, OPG proposed an additional CRVA Recoverability Threshold test, which compared total sustaining and CRVA in-service additions to the level of in-service additions factored into the EB-2013-0321 payment amounts. OPG proposed that the latter is the average 2014-2015 depreciation included in the approved EB-2013-0321 payment amounts ($143.3 million) escalated by the I –X price cap adjustment.[472] The amount recorded in the CRVA would be the lower of the threshold test and the CRVA Recoverability Threshold test.

Another issue arises because, under IRM there is not an explicit updating of the revenue requirement each year; however, just as the rates (payment amounts) are adjusted under the I –X price cap formula as proposed by OPG, so too implicitly is the revenue requirement adjusted. Therefore the amount of CRVA-related revenue requirement is also subject to this I – X adjustment. Starting from the $0.9 million annual amount as approved in EB-2013-0321, this will increase annually by the I –X adjustment, and will accumulate over time. Price-cap adjusted payments implicitly will recover some amount greater than the $0.9 million in each year of the IRM period, and the amount will increase over time, under the (reasonable) assumption that I – X > 0 in each year.[473] Using the $0.9 million as a fixed threshold will understate the amount being recovered in the payments, resulting in a double recovery – through payments and also through the CRVA of this incremental amount.

Concerns About Double Counting

OEB staff submits that OPG's revised proposal in Exh H1-1-2 with respect to in-service additions related to sustaining capital and CRVA eligible capital, and the CRVA

[470] Exh H1-1-2 page 3
[471] Tr Vol 15 pages 83-85
[472] Exh H1-1-2 Table 3
[473] This has been the case for all IRM plans approved by the OEB to date, generally. One exception was under 3 Generation IRM for electricity distributors where the poorest performing utilities, with the largest stretch factors, had a small negative I – X adjustment (-0.02%) in 2010 and 2011 when the GDP-IPI inflation factor was 1.3%.

Recoverability Threshold test is appropriate. The recording of supporting information for the disposition of the CRVA should be as detailed as the evidence in Exh H1-1-2.

However, OPG did not propose any change to the reference amount of $0.9 million described above.[474]

All else being equal, the price cap adjustment is applied equally to all components of the revenue requirement (expensed costs and capital-related costs), and the impacts accumulate over time in a multiplicative manner. And within the capital-related component of the revenue requirement, the price cap adjustment applies to both CRVA and non-CRVA eligible capital during the IRM period.[475]

There does need to be recognition of the cumulative and multiplicative impacts of adjustments over time under IRM, as PEG explained in testimony,[476] and as the OEB recognized in the revision to the formula for the materiality threshold for the ICM and ACM in the supplemental report on capital funding issued in January 2016.[477] OEB staff agrees with PEG and submits that a similar formulation needs to be applied to the CRVA as well as to the level of CRVA-qualifying capital funded through the price cap-adjusted payment amounts. OPG's CRVA Recoverability Threshold includes an element of inflation adjustment on capital. However, OEB staff submits that the I – X adjustment should also apply to the CRVA reference amount (i.e. the $0.9 million) presumed to be recovered through the payment amounts adjusted for price cap IRM formula over the term of the plan. The adjustment would address PEG's concern and would put the hydroelectric CRVA methodology on the same footing as exists for the ICM and ACM.

There is not a direct linkage between the CRVA and the X-factor, and any adjustment would be largely subjective. This is the first hydroelectric IRM plan for OPG, and there have been no precedents for it identified elsewhere. OEB staff submits that 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 is concerned about the possibility of unintended

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[474] Tr Vol 20 pages 68-80, Tr Vol 21 pages 22-40
[475] The CRVA also includes non-capital (i.e., expensed) costs. In Undertaking J20.6, OPG confirmed that the CRVA amount from EB-2013-0321 includes an annual average amount of $0.1M of expensed OM&A costs for CRVA-eligible projects. Expenses are recovered on a 1:1 basis as they are "current period" costs fully recoverable in the rate period that they are incurred in. As the mathematical formula shows, the I – X adjustment applies equally to OM&A expensed costs.
[476] Tr Vol 11 pages 25-27, pages 61-68, pages 127-134
[477] Report of the OEB on New Policy Options for the Funding of Capital Investments: Supplemental Report, January 22, 2016, pages 13-14

consequences of a subjective and likely arbitrary adjustment. Further, OEB staff submits that, with OPG's proposal in Exh H1-1-2 and with the adjustment for I – X escalation of the threshold amount of $0.9 million, the CRVA will properly be designed to meet the purposes as intended in the regulation and in which it has served its function under prior payments applications and decisions. No further adjustment to the X-factor to compensate for the CRVA is suggested at this time.

11.1.9 Hydroelectric Benchmarking

In the previous cost of service proceedings, OPG provided cost benchmarking based on raw database data from Navigant Consulting's Hydroelectric Generation Benchmarking Program and the Electricity Utility Cost Group annual OM&A benchmarking program. The analysis and reporting was completed by OPG. The EB-2013-0321 decision (pages 17-18) commented on the hydroelectric benchmarking filed in that proceeding and on expectations regarding future benchmarking.

> 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 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.

In the current proceeding, OPG filed a hydroelectric benchmarking study completed by Navigant Consulting, Inc. (Navigant). The study was based on 2013 data. Navigant found that OPG performed in the second quartile for reliability metrics (availability factor and forced outage rate). Navigant provided nine cost performance metrics in its report.

The summary[478] below lists the data in $million and not $/MWh or $/MW, however, the colour coding provides the benchmark performance for each cost metric.

CAD in Millions	OPG Adjusted Cost	1st Quartile Reference Cost	Median Reference Cost	3rd Quartile Reference Cost
1.Operations	23	21	28	47
2. Plant Maintenance	56	43	62	98
3. Waterways & Dams	9	10	18	39
4. Buildings & Grounds	16	6	13	35
5. Support	97	35	83	189
6. Partial Function	***201***	***114***	***203***	***408***
7. PA&R	326	28	115	218
8.Total Function	***527***	***142***	***318***	***625***
9. Investment	140	64	146	444
Total Costs Benchmarked	***666***	***206***	***463***	***1,069***

Top Quartile
Second Quartile
Third Quartile
Bottom Quartile

The costs at line 7 consist of Public Affairs and Regulatory (PA&R) costs. Navigant reported that OPG's PA&R costs are significantly higher than median at most locations. Navigant stated that the largest component of OPG's PA&R costs was the Gross Revenue Charge ($325 million of the total $326 million), which is not controllable by OPG and prescribed by regulation.[479]

OPG's performance on a Total Function Cost basis was third quartile (line 8). However, as a large part of total cost is the Gross Revenue Charge, Navigant concluded that Partial Function Cost (line 6), which includes functions that are regularly performed by all hydroelectric plants, was the key cost performance indicator for OPG's regulated hydroelectric facilities. As OPG's performance on Partial Function Cost was in the second quartile, OPG has proposed an IRM stretch factor of 0.3% for the five year application term.[480]

[478] Exh A1-3-2 Attachment 1 page 5
[479] Exh A1-3-2 Attachment 1 page 6
[480] Exh A1-3-2 page 6

In cross-examination,[481] OEB staff questioned the differences between the 2013 data used by Navigant[482] and the actual 2013 regulated hydroelectric data filed in the previous cost of service proceeding.[483] Based on OEB staff's review, the starting point total operating costs for 2013 should have been $786.0 million, while Navigant listed total costs of $733.4 million. OPG witnesses replied that Navigant did not always use accounting costs for the benchmarking. OM&A was based on FTEs plus labour burden, and investment cost was a five year average of the project OM&A and capital expenditures.

OPG provided a reconciliation in undertaking J9.2 of actual 2013 total regulated hydroelectric operating costs and actual 2013 total regulated hydroelectric OM&A with the Partial Function Cost determined by Navigant. OEB staff submits that the data at lines 4 to 6 and lines 21 to 27 of the undertaking were either not apparent or insufficiently explained in the initially filed evidence. There was minimal explanation provided for data excluded from the Partial Function Cost benchmarking, in particular the investment cost. There was minimal explanation of methodology and of when accounting data (i.e., 2013 actuals) were used or not used. OEB staff submits that the Navigant benchmarking is only marginally responsive to the OEB's EB-2013-0321 decision. However, for this application, OEB staff does not disagree with the use of Partial Function Cost benchmarking to underpin the stretch factor in the absence of better information; this is also discussed under the hydroelectric IRM proposal.

The summary above indicates that there is a significant difference between Partial Function Cost median ($203 million) and third quartile ($408 million). OEB staff submits that, despite lack of clarity on starting point total costs and exclusions, it is reasonable to conclude that OPG's Partial Function Cost performance ($201 million) is at or close to the median.

There is no standard methodology for determining the stretch factor; it is informed by both quantitative and qualitative analysis and considerations. Under the Price Cap IR method, the OEB assigns a 0.3% stretch factor to electricity distributors with average performance. An econometric model of total cost is used to determine distributor performance, and the stretch factor assignment is undertaken annually. The Navigant benchmarking filed by OPG relies on unit cost indices, and OPG proposes a 0.3% stretch factor for the entire five year term. As this is OPG's first IRM application, OEB staff submits that the benchmarking and stretch factor proposal are adequate, but that

[481] Tr Vol 9 pages 78-83
[482] Exh A1-3-2 Attachment 2 page 5
[483] EB-2013-0321 Exh L-1-Staff-2 Attachment 1

the OEB should set higher expectations for benchmarking in future hydroelectric IRM plans.

11.2 Nuclear Payment Amount Setting

Issue 11.3 (Oral Hearing) – Is OPG's approach to incentive rate-setting for establishing the nuclear payment amounts appropriate?
Issue 11.4 (Oral Hearing) – Does the Custom IR application adequately include expectations for productivity and efficiency gains relative to benchmarks and establish and appropriately structured incentive-based rate framework?
Issue 11.7 (Primary) – Is OPG's proposed off-ramp appropriate?

11.2.1 Nuclear Custom IR Form

Section 6(1) of O. Reg. 53/05 states that the OEB may establish, the form, methodology, assumptions and calculations used in determining OPG payment amounts. The OEB has commented on methodologies for setting payment amounts in the decisions of previous cost of service proceedings. In 2012, the OEB commissioned a report[484] on IR options for OPG, and the Report of the Board, *Incentive Rate-making for Ontario Power Generation's Prescribed Generation Assets*, EB-2012-0340 was issued on March 28, 2013. The report referred to the OEB's performance based approach, the renewed regulatory framework for electricity (RRFE),[485] and stated that:

> The Board remains of the view that a move to IR for the purposes of setting payment amounts for OPG's prescribed generation assets is appropriate. IR can further the Board's statutory objectives of protecting the interests of consumers and promoting economic efficiency while providing a stable planning environment for OPG. It is also consistent with the approach and objectives underlying the Board's renewed regulatory framework for electricity, including the promotion of cost-effective planning and operations and a longer-term view.

The form of OPG's 2017-2021 nuclear payment amounts application is in response to the OEB's letter of February 17, 2015 that stated, "The Board expects OPG to develop an IR framework for its hydroelectric assets, and a Custom IR framework for its nuclear assets based on the principles outlined in the RRFE."

[484] Incentive Rate Making Options for Ontario Power Generation's Prescribed Generation Asses, Power Advisory LLC, April 12, 2012
[485] Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach, October 18, 2012

OPG's nuclear Custom IR proposal includes a benchmark based stretch factor on base and allocated corporate OM&A, which OPG states will drive continuous improvement in its operations.[486] OPG stated that its proposal is consistent with the OEB's letter and compatible with the state of OPG's nuclear business during 2017-2021, referring to the significant changes related to DRP and PEO.[487] The OPG proposal does not include a nuclear industry productivity adjustment due the extent of OPG capital work in the test period. Moreover, OEB staff submits that it would be challenging to determine a nuclear industry productivity adjustment.

The proposal includes annual update of ROE to the OEB's prescribed ROE through a new account, the Nuclear ROE Variance Account. The OEB staff submission on this account is at section 9.3. OPG reports financial information to the OEB annually. OPG proposes that this reporting requirement be the basis for determining whether the proposed off ramp of +/-300 basis points for its ROE has been met.

The evidence at Exh A1-3-2 summarizes OPG's proposal with respect to the outcomes of the RRF. OPG stated that operational effectiveness would be achieved through its performance based business planning process, annual benchmarking, staffing and compensation strategies and extensive planning for DRP and Pickering Extended Operations. OPG does not have measurable performance objectives that are analogous to distributor CDM targets, but OPG is required to support the Long Term Energy Plan and other public policy objectives. Similarly, OPG does not have a direct relationship with electricity consumers, but every consumer in the province pays OPG's costs. OPG provided a summary of its work within communities and advisory groups.

On October 13, 2016, the OEB issued the *Handbook for Utility Rate Applications* (Rate Handbook). As noted on page 26, "The test for the adequacy of the application is the extent to which its features contribute to the achievement of the OEB's RRF goals and whether it meets the following standards …" Those standards are term, index for annual rate adjustment, benchmarking, performance metrics, updates and protecting customers. OPG's application was filed before the Rate Handbook was issued. With that in mind, OEB staff submits that the form of the nuclear Custom IR application generally meets the standards. OEB staff has further submissions on term and stretch factor below.

11.2.2 Nuclear Custom IR Term

[486] Exh A1-3-2 page 3
[487] Exh A1-3-2 page 23

A Custom IR application must have a minimum term of five years, and OPG has applied for the five year period 2017-2021.

OEB staff is satisfied that a five year term is appropriate and also accepts the off ramp proposed. However, OEB staff supports a mid-term review with a slightly different scope to the one proposed by OPG. This is discussed in section 11.3.2.

11.2.3 Stretch Factor

OPG proposes to apply a stretch factor to base OM&A and allocated corporate service OM&A. The determination of OPG's proposed stretch factor is set out at Chart 9 of Exh A1-3-2. OPG relied on the 2015 Nuclear Benchmarking Report, which summarizes performance for the 2014 year.[488] The performance metric relied on was three year rolling average Total Generating Cost (TGC). As Darlington is a top quartile performer on the basis of TGC, a stretch factor of 0% was assumed. As Pickering is a bottom quartile performer for TGC, a 0.6% stretch factor was assumed. On the basis of 2015 production, OPG determined that a 0.3% stretch factor was appropriate.

In cross-examination, OEB staff reviewed the OPG overall (i.e. not station specific) three year rolling average TGC. In 2014, OPG placed 10th out of a comparator group of 13 for TGC. Based on the 2016 Nuclear Benchmarking Report[489] filed in response to interrogatories, and which summarizes performance for the 2015 year, OPG's TGC had increased, and OPG placed 12th out of a comparator group of 13 for TGC. OPG replied that 2015 was a unique year due to the vacuum building outage, and that OPG did not plan to revise its application with respect to the stretch factor.[490]

OEB staff supports the use of three year rolling average TGC to determine the stretch factor. OEB staff submits that on the basis of the overall OPG TGC for 2014 and 2015, the stretch factor should be higher than 0.3%, and could be as high as 0.6%. While OPG provided reasons for the declines in TGC performance in 2015, OEB staff notes that the comparator group is subject to planned and forced outages as well, and that the TGC is determined on a three year rolling average to minimize the impact of single year events. In cross-examination, OPG stated that it had calculated the stretch factor using the 2015 data and stations specific TGC for Darlington and Pickering. OPG determined a stretch of 0.43% using these data.[491] Overall TGC performance of 12th out of a

[488] Exh F2-1-1 Attachment 1
[489] Exh L-6.2-SEC-63 Attachment 3
[490] Tr Vol 6 page 129
[491] Tr Vol 6 page 129

comparator group of 13 supports a 0.6% stretch factor. OEB staff submits that a 0.6% stretch is appropriate.

11.2.4 Application of the Stretch Factor

OPG proposes to apply the benchmark based stretch factor to nuclear base OM&A and corporate support OM&A allocated to nuclear, which according to OPG is 75% of the total nuclear OM&A. OPG proposes that the prior year's stretch reductions are carried forward to subsequent years. OPG states that this reduction would be in addition to the improvements reflected in its business plan.

In OPG's view, base OM&A and corporate support OM&A are areas where it is reasonable to drive efficiencies. The impact of OPG's proposed stretch is summarized at line 12 of the following table. Note that the impact has been subsequently updated through the impact statement Exh N1-1-1. For example, the 2021 impact is forecast to be $20.6 million instead of $20.4 million.

Table 40
Nuclear OM&A – Stretch Factor

	$million	2016 Budget	2016 Actual	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
1	Base	1,201.8	1,182.4	1,210.6	1,226.0	1,248.4	1,264.7	1,276.3
2	Project	98.2	89.3	113.7	109.1	100.1	100.2	86.6
3	Outage	321.2	306.7	394.6	393.8	415.3	394.4	308.5
4	SubTotal Operations	1,621.2	1,578.4	1,718.9	1,728.9	1,763.8	1,759.3	1,671.4
5	Darlington Refurbishment	1.3	3.1	41.5	13.8	3.5	48.4	19.7
6	Darlington New Nuclear	1.2	0.6	1.2	1.2	1.2	1.3	1.3
7	Corporate Costs	442.3	426.2	448.9	437.2	442.7	445.0	454.1
8	Centrally Held Costs	331.9	329.3	80.2	118.2	108.3	91.1	81.3
9	Asset Service Fee	28.4	34.1	27.9	27.9	28.3	22.9	20.7
10	SubTotal Other	805.1	793.3	599.7	598.3	584.0	608.7	577.1
11	**Total OM&A**	**2,426.3**	**2,371.7**	**2,318.6**	**2,327.2**	**2,347.8**	**2,368.0**	**2,248.5**
12	0.3% Stretch on Base & Corporate, Exh A1-3-2				5.0	10.1	15.2	20.4
13	0.6% Stretch on OM&A except DRP				13.9	27.9	41.9	55.2
	Source: Exh F2-1-1 Table 1, Undertaking J14.2 Attachment 1							

OEB staff notes that under normal IRM rate setting, the productivity and stretch factors effectively apply to all OM&A and capital. In cross-examination, OPG stated that its capital project process is different from distributors.[492] OPG employs a portfolio

[492] Tr Vol 6 page 138

management approach, and there are always more projects than budget. This in OPG's view means that it is inherently incented to become as efficient as possible on capital. Further, much of the work is related to safety and regulatory requirements. OEB staff notes that these conditions, relatively speaking, apply to the largest electricity distributors as well.

Under Custom IR, there are examples of plans for which the OEB applied a stretch factor to capital (for example, Toronto Hydro-Electric System Ltd.),[493] and where it did not (Hydro Ottawa Limited).[494] OEB staff is not proposing a stretch factor on capital for OPG's current Custom IR plan, in part because the compatibility with the CRVA was not sufficiently tested in this proceeding. OEB staff does not concede at a broader level that a stretch factor should never apply to capital under Custom IR for OPG.

OPG's proposal applies the stretch factor to nuclear base OM&A and corporate support OM&A allocated to nuclear, lines 1 and 7 in the table above. In response to cross-examination regarding project and outage OM&A, OPG stated that discrete projects are funded by project OM&A, and that there is little repetition. Regarding outage OM&A, OPG stated that each outage is a unique endeavour. In response to cross examination by the PWU, OPG stated that it will be challenged to achieve the stretch factor it has proposed (i.e. line 12 of the above table).

OEB staff does not accept that the stretch factor should apply only to nuclear base OM&A and corporate support OM&A allocated to nuclear. OEB staff submits that the stretch factor should also apply to nuclear project and outage OM&A. OEB staff sees no reason why OPG should not be incentivized to find additional efficiencies under these categories.

OEB staff notes that in 2017, OPG proposes a step increase in both project and outage OM&A vs 2016 budget, a total of $89 million or 21%. OEB staff submits that there is some element of repetition in project OM&A work (e.g. project management and administration), and in outage OM&A work. Darlington units are on a 3 year outage cycle and Pickering units are on a 2 year outage cycle. While there may be some unique work in each outage, there will be work that has been done before, in some cases, many times before. Further, staff notes that 2016 actuals for each of base, project, outage and allocated corporate OM&A was lower than 2016 budget, a total of $58.9 million.

[493] EB-2014-0116
[494] EB-2015-0004

Under IRM and Custom IR, the stretch factor is applied to all OM&A, with the expectation of efficiency improvements in all aspects of OM&A. OEB staff notes that Darlington Refurbishment OM&A would be subject to CRVA treatment, but submits that the rest of nuclear OM&A should be subject to a stretch factor. The impact is noted on line 13 of the table above.

11.3 Mid-Term Review

Issue 11.5 (Primary) – Is OPG's proposed mid-term review appropriate?
Issue 9.8 (Primary) – Should any newly proposed deferral and variance accounts be approved by the OEB?

11.3.1 Background

OPG seeks approval of a mid-term review of production forecast to reflect the 2019-2021 business plan. An application would be filed in the first quarter of 2019 to review production forecast for the period from July 1, 2019 to December 31, 2021, related nuclear fuel cost, and disposition of audited 2018 year end deferral and variance account balances. The impacts of the production forecast review would be recorded in the proposed Mid-term Nuclear Production Variance Account.

11.3.2 OEB Staff Submission

OPG's proposal to review production forecast only at the mid-term review is based on its interpretation of O. Reg. 53/05 is provided at page 12 of Exh A1-3-3:

> Subject to the OEB concluding that rates are no longer just and reasonable pursuant to Section 78.1 of the Act, the regulation does not entitle the OEB to revisit those approved revenue requirement amounts during the five years. However, while the revenue requirement must be determined on a five-year basis, no such limitation exists for the determination of production.

Despite this interpretation, OPG's proposal would adjust revenue requirement related to nuclear fuel as it is a direct marginal cost. OEB staff notes that on the basis of the 2016 Nuclear Benchmarking Report, the fuel cost for Pickering is $5.71 million per TWh, and for Darlington is $5.18 million per TWh. An illustrative example for a 1 TWh variance in 2020 is provided at Exh L-11.5-Staff-259.

OPG's evidence at Exh E2-1-1 Chart 2 summarizes historical planned and historical actual production forecast. The actual production has been lower than planned for every year. OPG proposes to continue with its production forecast for the first half of the test period. However, there is uncertainty related to the production forecast for the latter half of the test period and contributing factors are listed on pages 11 and 12 of Exh A1-3-3.

The norm for distributors on five year Custom IR is no load forecast adjustments in the term. This is also consistent with the expectations set out in the Rate Handbook.[495] Utilities are expected to live within their means during the Custom IR term. OPG states that its circumstances are different from distributors as payment amounts are fully variable. OEB staff notes, however, that OPG has a suite of deferral and variance accounts that guarantee recovery of significant costs, e.g. Nuclear Liability Variance Account, Bruce Lease Net Revenue Variance Account, Capacity Refurbishment Variance Account, and the Rate Smoothing Deferral Account.

In cross-examination, OPG agreed that the most significant production forecast risks are DRP and Pickering Extended Operations.[496] OEB staff has prepared the following list of some potential scenarios relating to DRP and PEO in the test period. All of these scenarios would have a significant impact on test period production forecast.

Scenario	Test Period Production Forecast Impact
Darlington Unit 2 refurbishment is completed later than February 2020. Unit 3 refurbishment is delayed and Unit 1 refurbishment does not start in the test period.	Increase
Darlington Unit 2 refurbishment is completed earlier than February 2020. Unit 3 refurbishment is advanced and Unit 1 refurbishment is advanced.	Decrease
Pickering licence is not extended beyond August 2018 by CNSC	Decrease
Pickering operation beyond 2020 is not approved by CNSC	Decrease
Pickering operation beyond 2020 is not provided for in 2017 LTEP	Decrease

Given the significant investment in planning of the DRP and PEO, there is an argument to be made that the production forecast should hold for the entire five year Custom IR term. OEB staff submits that any event requiring Pickering to shut down sooner than

[495] Handbook for Utility Rate Applications page 26
[496] Tr Vol 6 pages 149-153

OPG plans would result in an application to the OEB at the time of the event. This was confirmed by OPG in cross-examination.[497] It is staff's view that, should the OEB approve a mid-term review, the mid-term review should only consider matters related to the DRP, subject to staff's recommendation that the OEB may wish to allow OPG to also bring forth a request to transition back to accrual account as the rate-setting mechanism for pension and OPEBs. Given that a new proceeding would be required if Pickering were to shut down early, OEB staff sees no reason for any further protections relating to Pickering's production forecast.

Should the OEB approve a mid-term review as proposed by OPG, OEB staff submits that the review consider only the last two years of the term. There have been three proceedings that considered two year cost of service applications. In every instance, there has been a one year lag between those test periods.

Should the OEB not approve a mid-term review, OPG proposes to file an application to clear the balances in deferral and variance accounts. OEB staff notes that the EB-2013-0321 decision discouraged standalone deferral and variance account applications.

11.3.1 Mid-term Nuclear Production Variance Account

OPG has requested that the OEB establish the Mid-term Nuclear Production Variance Account in this proceeding. OPG proposes this account to be effective July 1, 2019. The proposed account would record the impact of the production variance from July 1, 2019 to December 31, 2021. The additions proposed to the account are outside the base upon which rates were derived. The entries into the account will be calculated based on the monthly production variance multiplied by the approved smoothed nuclear payment amount and then reduced by the monthly production variance multiplied by the average fuel cost in the approved revenue requirement for the applicable year. The additions proposed to the account are to mitigate the production risk in setting nuclear payment amounts over a five year term.

OEB staff submits that the account does not need to be created until the mid-term review application is filed and processed. A determination regarding causation, prudence and materiality of the proposed account should be made at that time.

[497] Tr Vol 6 page 157

11.4 Payment Amount Smoothing

Issue 1.3 (Oral Hearing) – Is the overall increase in nuclear payment amounts including rate riders reasonable given the overall bill impact on customers?
Issue 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?
Issue 11.6 (Oral Hearing) – Is OPG's proposal for smoothing nuclear payment amounts consistent with O. Reg. 53/05 and appropriate?

11.4.1 OPG's Proposal

In its pre-filed evidence, pursuant to s. 5.5 of O. Reg. 53/05, OPG proposed a rate smoothing mechanism whereby annual nuclear base payment amounts would increase at a constant 11% per year during the 2017 to 2021 test period.[498] The proposal would have resulted in an average increase of approximately $1.05 on the typical residential customer's monthly bill each year.[499]

On March 2, 2017, O. Reg. 53/05 was amended. Six days later, OPG filed a revised rate smoothing proposal.[500] Under the revised proposal, the weighted average payment amount (WAPA) (which, as per the amended regulation, includes both the hydroelectric and nuclear payment amounts, as well as riders) would increase by a constant 2.5% per year during the test period. The result would be that collection of approximately $1 billion of revenue requirement would be deferred beyond that period.

OPG explained that the bill impact for a typical residential customer would be an average annual increase of $0.65 on the monthly bill during the test period.[501]

11.4.2 The Legislative Context

"Smoothing" is required under O. Reg. 53/05. The regulation stipulates that the OEB must determine how much of the nuclear revenue requirement should be deferred, "with a view to making more stable the year-over-year changes in the OPG weighted average payment amount over each calculation period".[502] The deferred amounts are recorded

[498] Exh A1-3-3 page 1.
[499] Exh A1-3-3 page 2.
[500] Exh N3-1-1.
[501] Exh N3-1-1 page 2.
[502] O. Reg. 53/05, s. 6(2)12 (Exh A1-6-1 Attachment 1). The regulation defines the deferral period in s. 0.1(1) as "the period beginning on January 1, 2017, and ending when the Darlington Refurbishment Project ends."

in a rate smoothing deferral account (RSDA) which earns compound interest at the OEB-approved long-term debt rate for OPG.[503] The regulation also establishes that the balance in the RSDA is be recovered over a period of not more than 10 years, which begins when the DRP is completed.[504]

The mechanics of smoothing, including the determination of how much of the nuclear revenue requirement should be deferred, are left largely to the OEB's discretion. As OPG acknowledged in cross-examination, there are any number of smoothing scenarios that might comply with the regulation.[505]

11.4.3 OEB Staff's Concerns with OPG's Proposal

OPG explains in its application that its smoothing proposal was guided by a number of principles, namely:

1. Financial viability
2. Rate stability
3. Long-term perspective
4. Post-recovery transition
5. Intergenerational equity
6. Customer bill impact[506]

OEB staff does not dispute that these are appropriate considerations. However, OEB staff submits that, in evaluating these factors, the OEB should not lose sight of the overarching principle that smoothing must strike an appropriate balance between costs and benefits for both customers and OPG. Put another way, the OEB should strive to ensure proportionality between the solution and the problem it is meant to address.

For customers, OPG's proposal would be expensive. About $1 billion of revenue requirement would be deferred to future generations. As required by the regulation, this deferred amount would earn compound interest at the approved long-term debt rate. That is more than OPG earns on other deferral and variance accounts.[507] OPG calculates that $116 million in cumulative interest would accrue during the test period.[508] Over the entire time horizon for OPG's proposal (i.e., the forecast 10-year deferral

[503] O. Reg. 53/05, s. 5.5(1) (Exh A1-6-1 Attachment 1 page 4).
[504] O. Reg. 53/05, s. 6(2)12 (Exh A1-6-1 Attachment 1).
[505] Tr Vol 22 pages 44 and 49.
[506] Exh N3-1-1 pages 5-6.
[507] Tr Vol 22 page 46.
[508] Tr Vol 22 page 40.

period plus the 10-year recovery period), the cumulative interest would amount to $1.4 billion.[509]

Customers might reasonably ask what they would get in exchange for the $116 million they would need to pay OPG for smoothing during the test period. For residential customers, the pocketbook implications of rate smoothing might be barely perceptible. As shown in in the table in Schedule A at lines 14 and 15, if there were no smoothing at all, the average monthly bill impact of the OEB's approval of OPG's revenue requirement as proposed would be $0.82 per year; with OPG's proposed WAPA smoothing, the impact would be $0.65. The unsmoothed impact of $0.82 represents an average increase of about 0.5% on the typical consumer's bill of $150.[510] That is well below the 10% threshold the OEB normally uses when assessing whether to require mitigation in the distribution context.[511] It is true that in the no-smoothing scenario, there would be variability in the bill impacts, with the biggest increases coming in 2017 and 2020 ($2.06 and $3.67, respectively). Still, even those increases fall well below the 10% threshold.

The net effect of OPG's smoothing proposal for the typical residential customer is a saving of only 17 cents per month ($0.82 minus $0.65) on a bill of about $150. And that is before the impact of any rate reductions that may be implemented by way of the Province's recently announced Fair Hydro Plan. The Province has indicated that electricity bills will be reduced by 25% for residential customers as well as many small businesses and farms, and that bills will not increase beyond the rate of inflation for at least four years.[512] Legislation to that effect was tabled on May 11, 2017, after the oral hearing ended, but has not yet been passed, and many of the details would be left to regulations which have not yet been released.[513] Assuming the Fair Hydro Plan is implemented along those lines, the rationale for smoothing of OPG's payment amounts, at least in respect of residential customers and any other customers protected under the plan, would seem to be attenuated. The Fair Hydro Plan appears to be a form of rate smoothing in its own right. OPG's proposal for a constant 2.5% WAPA increase would amount to smoothing on top of smoothing. It would be unnecessary..

[509] Tr Vol 22 page 50. In cross-examination, OPG explained that its revised smoothing proposal was built on the assumption that there would be $1.4 billion in total interest, because that is the amount of interest that would have accrued under its initial proposal: Tr Vol. 22 pages 50-51. OEB staff submits that OPG put the cart before the horse. It would have been more reasonable to first consider what an appropriate level of WAPA smoothing would look like, and then to calculate the total interest.
[510] OPG assumed an average residential bill of $150. OEB staff notes that, as a result of the Province's decision to rebate the provincial portion of the HST on electricity bills as of January 1, 2017, the typical bill is now closer to $140.
[511] OEB Handbook for Utility Rate Applications, October 13, 2016 (Exh K22.2 page 16)
[512] Ontario's Fair Hydro Plan (Exh K22.2 page 18)
[513] Bill 132, the *Fair Hydro Act, 2017*

In designing its smoothing proposal, OPG did not take the Fair Hydro Plan into account.[514] Although the details were not (and still are not) known, OEB staff submits that it would be appropriate for the OEB to consider whether the plan alleviates some of the concerns that might otherwise justify a significant smoothing of OPG's WAPA.

Much of OPG's application in respect of smoothing – and much of the discussion in cross-examination – focused on the bill impacts of various smoothing scenarios for residential consumers. But the impact on other classes should also be considered, some of which may not see the full 25% reduction promised in the Fair Hydro Plan.

For customers, WAPA smoothing is roughly analogous to choosing a longer amortization period when taking out a home mortgage. It might result in slightly lower monthly payments, but over the long term it costs more than paying the loan off sooner. The analogy is imperfect though. For one thing, it does not account for the bill impacts of the Fair Hydro Plan. Another difference is that in the mortgage example, questions of intergenerational equity do not arise.

For OPG too, smoothing has a cost. OPG is guaranteed recovery of any amounts placed in the smoothing deferral account.[515] Nevertheless, the more revenue collection is deferred, the more of an impact on OPG's cash flow (and, accordingly, on OPG's credit metrics and ultimately on its cost of borrowing) there would be.[516]

In summary, OEB staff submits that the negligible benefits of OPG's smoothing proposal do not warrant the significant costs for customers – both current and future generations – as well as for OPG itself.

Three other points are worth making. First, the case for OPG's smoothing proposal would be further weakened if the OEB were to find that OPG's revenue requirement request is too high. In other words, if the OEB were to disallow some of OPG's costs or to approve a higher nuclear stretch factor – as OEB staff has suggested above – then the bill impact on customers of all classes would be lessened and there would be a less compelling argument for smoothing.

Second, there is another way for the OEB to smooth bill impacts without adding to the RSDA. That is through the disposition of OPG's various deferral and variance accounts.

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[514] Tr Vol 22 pages 12-14 and 52-53.
[515] O. Reg. 53/05, s. 6(2)12iv. says "the Board shall ensure that Ontario Power Generation Inc. recovers the balance recorded in the deferral account…"
[516] Tr Vol 22 pages 40-41; Tr Vol 18 page 9.

OPG has proposed clearance of the 2015 year-end balances in certain deferral and variance accounts in two year riders in this proceeding. OPG also proposes to request disposition of deferral and variance accounts in a mid-term review in 2019. In both circumstances, the OEB could take into consideration the goal of reducing bill volatility for customers, and adjust the timing of disposition accordingly. The OEB could also consider different disposition weightings to reduce bill volatility. In the EB-2012-0002 OPG deferral and variance account proceeding, the OEB approved a settlement proposal that weighted disposition into 60% in 2013 and 40% in 2014. OEB staff proposes that the 2015 year-end balances be disposed of over three years, instead of the two proposed by OPG, on the following basis: 25% in 2017, 25% in 2018 and 50% in 2019. Another option for the OEB to consider is two year riders that are effective on July 1, 2017 and end on June 30, 2019. This would also smooth WAPA.

Third, if in this proceeding the OEB pre-approves less than the full amount of DRP contingency requested by OPG, the benefits of significant revenue deferral would be reduced. Approving DRP spending at a P37 confidence level, as OEB staff has recommended, would create a natural smoothing effect. As explained in section 4.3.8, if OPG actually spent more on Unit 2 than what was approved, it would recover the revenue requirement impact of the difference through the CRVA in a future proceeding, presumably after 2021. The CRVA would act as a cheaper (for ratepayers) smoothing mechanism than the RSDA, as the effective interest rate on the CRVA is lower.

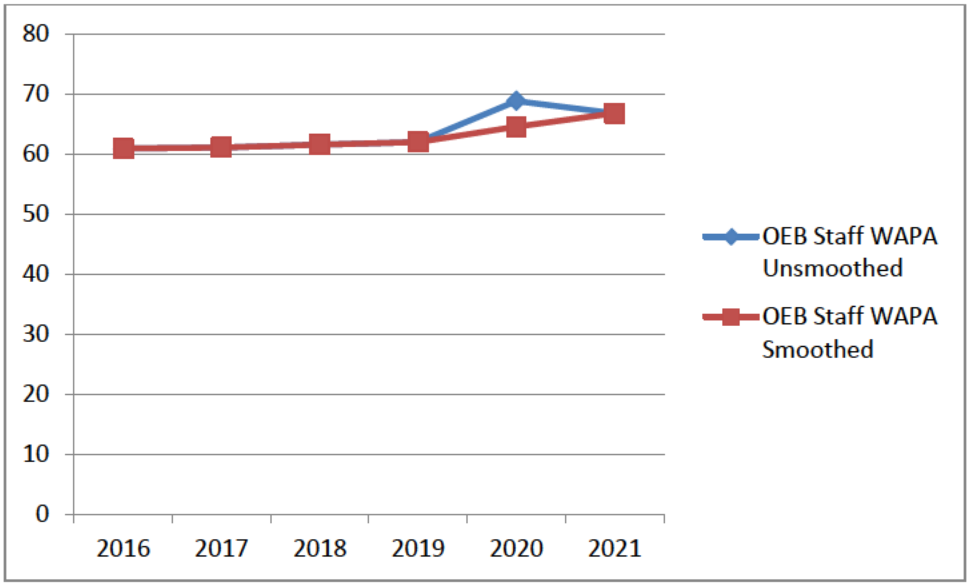
11.4.4 An Alternative Smoothing Proposal

For the reasons above, OEB staff submits that OPG's proposal for a constant 2.5% WAPA increase would result in too much revenue deferred to future generations and carrying costs that are too high.

Zero smoothing is not an option; the regulation requires that the WAPA be made "more stable".

OEB staff proposes a middle ground approach. Rather than aiming for a constant rate of increase for the WAPA, the OEB should focus on what OEB staff called in cross-examination "rounding off the edges".[517] In other words, the OEB should only defer revenue collection in years where there would otherwise be an especially high peak or deep trough in the WAPA. This is illustrated in the figure below.

[517] Tr. Vol 22 page 43.



This figure is based on the WAPA that would result if the OEB adopted OEB staff's recommendations set out earlier in these submissions, for example, the approval of DRP spending at the P37 confidence level, the application of a 0.29% TFP on the hydroelectric side, and the disposition of the 2015 year-end deferral and variance account balances over three years.

The figure shows that, even absent any smoothing, the WAPA would be quite flat. It is only in 2020, when Unit 2 comes back into service, that the WAPA would see a relatively sharp increase. It is therefore only in 2020 that, in OEB staff's view, smoothing should be applied. Under staff's proposal, instead of spiking in 2020 and then declining in 2021, the WAPA would increase gradually.[518]

OEB staff calculates that its smoothing proposal would result in the deferral of approximately $300 million during the test period, much less than the roughly $1 billion under OPG's proposal. The total interest during the test period would be $21 million, compared to $116 million under OPG's proposal. The monthly bill impact for residential customers would average $0.47 per year, with the largest increase, of $1.03, occurring in 2020.[519]

[518] OEB staff arrived at the 2020 smoothed WAPA of $64.59 by reducing the nuclear payment amount from $92.11 to $84.00, as shown in Schedule A.
[519] This is shown in lines 28-30 of Schedule A

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 -

SCHEDULE A – Summary of OEB Staff Submission

		2016	2017	2018	2019	2020	2021	Total/Ave	Notes
1	**OPG Proposed (Exh N3 Mar 8, 2017)**								
2	Hydroelectric Payment Amount ($/MWh)	40.72	41.71	42 33	42.97	43.61	44.27		
3	Hydroelectric DVA Rider ($/MWh)	3.83	1.44	1.44					
4	Nuclear Revenue Requirement ($M)		3161.4	3185.7	3273.2	3783.5	3397 8		
5	Production Forecast (TWh)	46.8	38.1	38.47	39.03	37.36	35.38		
6	Unsmoothed Nuclear Payment ($/MWh)	59.29	82.98	82 81	83.86	101.27	96.04		
7	Smoothed Nuclear Payment ($/MWh)	59.29	76.39	78.60	84.83	88.21	92.02		
8	Nuclear DVA Rider ($/MWh)	13.01	2.85	2 85					
9	Equity Thickness	45%	49%	49%	49%	49%	49%		
10	WAPA Smoothed ($/MWh)	60.97	62.49	64 06	65.66	67.30	68.98		
11	Bill Impact WAPA Smoothed ($/month)		0.62	0.64	0.66	0.66	0.66	0.65	
12	RSDA Additions - Smoothed ($M)		251	162	-38	488	142	1005	
13	RSDA Interest ($M)		6	16	19	30	45	116	
14	WAPA Unsmoothed ($/MWh)	60.97	66.03	66 33	65.14	74.24	71.06		As calculated by OEB staff and confirmed by
15	Bill Impact WAPA Unsmoothed ($/month)		2.06	0.13	-0.49	3.67	-1.25	0.82	OPG - Tr Vol 22 (no additions to RSDA)
16	**OEB Staff Submission**								
17	Hydroelectric Payment Amount ($/MWh)	40.72	41.46	41 84	42.22	42.60	42.99		
18	Hydroelectric DVA Rider ($/MWh)	3.83	0.66	0.66	1.32				3 year disposition (25%,25%,50%)
19	Nuclear Revenue Requirement ($M)		2932.5	2975.0	2953.2	3441.3	3150.1		See table below
20	Production Forecast (TWh)	46.8	38.6	38 97	39.53	37.36	35.38		
21	Unsmoothed Nuclear Payment ($/MWh)	59.29	75.97	76 34	74.71	92.11	89.04		
22	Smoothed Nuclear Payment ($/MWh)	59.29	75.97	76 34	74.71	84.00	89.04		
23	Nuclear DVA Rider ($/MWh)	13.01	1.41	1.40	2.76				3 year disposition (25%,25%,50%)
24	Equity Thickness	45%	47%	47%	47%	47%	47%		
25	WAPA Unsmoothed ($/MWh)	60.97	61.13	61 59	62.03	68.90	66.82		
26	Bill Impact WAPA Unsmoothed ($/month)		0.07	0.19	0.19	2.77	-0.81	0.48	
27	WAPA Smoothed ($/MWh)	60.97	61.13	61 59	62.03	64.59	66.82		
28	Bill Impact WAPA Smoothed ($/month)		0.07	0.19	0.19	1.03	0.88	0.47	
29	RSDA Additions - Smoothed ($M)					303		303	
30	RSDA Interest ($M)					7	14	21	
31	Initial Nuclear Revenue Requirement		3161.4	3185.7	3273.2	3783.5	3397 8	16,802	
32	Base OM&A		40.0	40.0	40.0	40.0	40 0		Section 6.1.1
33	Outage OM&A		19.7	19.7	20 8	19.7	15.4		Section 6.1.2
34	Corporate OM&A		20.1	4.1	5.3	3.2	7 9		Section 6.8
35	Compensation		50.0	50.0	50.0	50.0	50 0		Section 6.7.4
36	PEO - Enabling Costs				107.0	104.0			Secton 6.5.6, CRVA Eligible
37	Nuclear Fuel Bundles		3.3	3.2	3.2	3.3	3 0		2% reduction per settlement
38	Nuclear Fuel (increased TWh)		-2.9	-2.9	-2.9				Section 5.2 and 6.4
	Stretch Factor			13.3	26.5	39.7	53 0		Section 11.2.4
				5.0	10.2	15.3	20.6		EB-2016-0152 application
39				8.3	16.3	24.4	32.4		Net additional stretch
40	DRP Rate Base Additions		2.5	2.5	2.5	22.0	26 9		Section 4.3.2
41	Nuclear Op. Rate Base Additions		19.7	14.1	8.7	10.7	19 8		Section 4.1.2
42	Equity Thickness		3.8	4.0	2.8	6.2	6.6		Section 3.3
43	Nuclear Liability		69.7	66.9	65.6	57.8	44 8		Section 8.2
44	Other Revenue		3.1	0.7	0.8	0.8	0 9		Per settlement
45									
46	Final Nuclear Revenue Requirement		2932.5	2975.0	2953.2	3441.3	3150.1	15,452	