Saba Zadeh
Director

Ontario Regulatory Affairs

700 University Avenue, Toronto, Ontario M5G 1X6

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

June 19, 2017

VIA RESS AND COURIER

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

Dear Ms. Walli:

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

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

Best Regards,

[Original signed by]

Saba Zadeh

Attach

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

EB-2016-0152

OEB Application

for

Payment Amounts for OPG’s Prescribed Facilities

Reply Argument

Ontario Power Generation Inc.

June 19, 2017

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1.0 OVERVIEW

In the sections that follow, OPG responds to the submissions of OEB staff and the intervenors in detail, issue by issue. Here, OPG moves beyond the specifics of the arguments to discuss this proceeding in terms of what it means for customers and for the implementation of public policy.

The outcomes of this proceeding will affect Ontarians for years to come. In its decision the OEB will determine the appropriate regulatory treatment for billions of dollars of investment in the Darlington Refurbishment Program ("DRP" or "Program"). The OEB will resolve requests that it decide the "need" for Pickering to operate before establishing its reasonable costs. It will move OPG from cost of service to incentive regulation ("IR"). Ultimately, it will determine the funds OPG will have to operate and invest in the regulated facilities over the 2017-2021 period; the return it will earn on investment; and how much households and businesses will pay for OPG's share of the electricity they consume and how much will be deferred for future recovery. Put simply, this is an important application for Ontario.

Darlington Refurbishment

As set out in the 2013 Long-term Energy Plan ("LTEP"), "The government is committed to nuclear power. It will continue to be the backbone of our electricity system, supplying about half of Ontario's electricity generation." Consistent with this public policy, the Government has authorized the DRP, a $12.8B investment in Ontario's future. In this Application, OPG seeks approval to recover the capital expenditures made for the first parts of this effort – planning the Program, refurbishing Darlington Unit 2 and completing other projects that are necessary to allow OPG to execute refurbishment or to enable Darlington to operate safely and reliably for an additional 30 years, once refurbished.

The Government has been and remains engaged with the DRP. As the OEB heard, the Ministry of Energy, supported by experts, is providing ongoing oversight. OPG's Board of Directors also has retained experts to assist in their oversight role and OPG's CEO has convened an expert review board that works with senior management to evaluate the Program's progress and suggest ways to improve it. Beyond oversight, OPG is committed to transparent reporting for DRP. To keep the public informed about the Program, OPG's website (www.opg.com) has a tab for the DRP on its homepage with a variety of information, including a monthly progress report. To keep the OEB informed on the DRP's progress, OPG has proposed detailed annual reporting.

Pickering Extended Operations

This Application also seeks approval of the funds necessary to allow Pickering to operate to 2024, four years after its previously planned shutdown. Pickering has been and remains a cost-effective source of electricity for the Province of Ontario ("Province"). OPG's plan to continue operating it during a time when Ontario's electricity supply is undergoing major transformation makes sense and is supported by the IESO. This is why the Minister of Energy initially approved OPG's plan and continues to support it.

As is abundantly clear from their submissions, some parties disagree with the Government's policy choice. They oppose extending Pickering's operation and some even argue it should close early, in 2018. In this proceeding, they have advanced their opposition in the form of unsupported claims about the cost of Pickering relative to unspecified alternatives and the amount of energy it will produce. The OEB should discount these submissions as they lack any evidentiary basis.

The OEB is well aware of what customers pay for OPG's nuclear production; it sets the rates. The OEB is also aware of OPG's nuclear production, both forecast and actual, because it approves the production forecast. The same cannot be said for the cost and availability of the ill-defined alternatives that parties like ED and GEC say will save customers billions of dollars. "Back of the envelope" calculations, such as those ED acknowledges providing in its argument, are no substitute for evidence that has been filed and tested. They cannot assist the OEB in fulfilling its statutory mandate to determine just and reasonable payment amounts based on the record of this proceeding.

Regulatory Framework

This Application also marks a turning point away from purely cost-based regulation toward incentive ratemaking. OPG's proposal for the hydroelectric and nuclear assets is well grounded in the OEB's incentive-ratemaking paradigm. The hydroelectric incentive rate-setting mechanism ("IRM") proposal is modeled after the OEB's Renewed Regulatory Framework for

Electricity Distributors ("RRFE"), while the custom approach for the nuclear facilities incorporates those incentive elements that are appropriate given the major nuclear initiatives discussed above. OPG sees this Application as an important first step in aligning the regulation of OPG with the RRFE.

The substantial productivity enhancements contained in the Application will benefit customers over the five-year IR term. For hydroelectric, OPG proposes using the payment amounts set in OPG's last application as the starting point for the price-cap formula, with no adjustment for inflation since that application. OPG also proposes incorporating the OEB's previously adopted productivity floor, which sets a "zero" productivity factor, despite the negative productivity factor found in the expert study that OPG filed. For both hydroelectric and nuclear, OPG will be challenged to find incremental cost savings beyond those already envisioned as required by the stretch factor, but in any event, the stretch factor operates to ensure that customers receive these savings.

The nuclear custom incentive ratemaking proposal continues to rely on individual annual revenue requirements, but it is important to note that OPG's total nuclear operating costs are stable over the IR term. Even before the application of the stretch factor, projected increases in nuclear operating cost over the IR term are below reasonably anticipated inflation. This stability demonstrates OPG's continuing commitment to cost control. OPG submits that it is the overall level of costs that is relevant, rather than a line-by-line analysis of individual cost elements, because it is the total cost that impacts the rates customers pay.

Compensation and Benefits

OPG's commitment to cost control is prominent in the compensation and benefits area. There, OPG, with the assistance of Government, was able to negotiate material increases in employee pension contributions as well as changes to pension eligibility and payment formula rules. These changes will produce savings that grow over time. While OPG's efforts will continue, it is undeniable that real progress has been made. That progress can also be seen in the results of the compensation and benefits benchmarking where Willis Towers Watson found that overall OPG's wages and salaries, including incentive payments, were in line with those of comparable companies.

Benchmarking

OPG's evidence includes a substantial number of benchmarking reports beyond compensation and benefits. In OPG's view, benchmarking is a valuable tool for measuring relative performance in order to identify potential areas for improvement. This is how OPG uses benchmarking and, in its respectful submission, how the OEB should use it as well. In this Application, as in past hearings, parties place more weight on benchmarking results than they can hold. While the compensation benchmarking demonstrates that overall, OPG's wages and incentives are in the range of the comparator group, it does not provide a mathematical formula that OPG, or the OEB, can reasonably use to set compensation. Similarly, the nuclear staffing benchmarking shows in broad terms that OPG's staff levels are comparable to those of other nuclear operators, but it cannot be taken as a staffing plan.

Nuclear Liabilities

At the core of OPG's commitment to the public is safety. Beyond safely operating the nuclear stations, this also includes the obligation to safely dispose of the used fuel and other nuclear waste they produce and safely decommission them upon shutdown. While OPG no longer operates the Bruce facilities, it retains the obligation for their nuclear waste and decommissioning. In order to ensure adequate funding is available to address these obligations, some of which will arise decades from now, the Province created segregated funds, provided initial funding and required OPG to fund the remainder of these obligations on an accelerated basis. In OPG's first application, the OEB carefully determined how the cost of these ongoing obligations should be recovered by OPG and has consistently followed the adopted approach in later cases. It should do so again, despite the submissions to the contrary, because the adopted approach correctly addresses the long-term nature and ongoing cost of OPG's nuclear liabilities in a fair and transparent manner.

Equity Thickness

Capital structure is an important consideration for any regulated utility. Since it began regulating OPG, the OEB has determined that the capital invested in OPG's regulated business, as a whole, should earn a return commensurate with its risk. In the last hearing, the OEB decreased OPG's equity thickness because it found that the increased proportion of hydroelectric assets in rate base lowered OPG's risk. The same logic requires that the OEB increase OPG's equity thickness in this proceeding now that the proportion of nuclear assets is increasing and to recognize the risks associated with the increased capital spending on DRP and Pickering Extended Operations.

Outcomes

Ultimately, this process will set the rates that customers pay for the next five years. To arrive at these, the OEB will determine how much of OPG's nuclear revenue requirement and deferral and variance ("D&V") account balances should be recovered over this IR term and how much should be deferred under the rate smoothing regulation. OPG's proposal would increase the weighted average payment amounts at 2.5% per year over the IR term. For a typical residential customer, that translates into a bill impact of about 65 cents a month.

OPG faces unprecedented challenges over the next five years as it executes the DRP, extends Pickering's operation, and manages its costs within the budget envelope provided by incentive ratemaking, all while striving to earn an appropriate return on investment for its ultimate owners, the people of Ontario. To fulfill its role as Ontario's low-cost electricity provider, OPG must operate reliably and its variable rate structure provides a strong incentive to do so. OPG respectfully requests that the OEB carefully consider the evidence and arguments in this complex proceeding and arrive at a decision that provides OPG with a reasonable return on investment and the funding necessary to continue generating clean and reliable electricity.

2.0 GENERAL

2.1 Issue 1.1

Secondary: Has OPG responded appropriately to all relevant OEB directions from previous proceedings?

LPMA was the only party with a submission on this issue and agrees that OPG has appropriately responded to all relevant directions. In Ex. A1-11-1, OPG provides a table that identifies the OEB directives from prior proceedings and the exhibit number(s) in this Application where OPG's evidence discusses the responses to the directives. As demonstrated in that table, the referenced exhibits, and the submissions below, OPG has responded to all relevant OEB directions from previous proceedings. As such, OPG submits that the OEB should find that OPG has appropriately responded to this issue.

2.2 Issue 1.2

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

OPG received only one submission on this issue from LPMA. LPMA accepts all of OPG's business planning assumptions except for the rate of inflation and PEO (LPMA argument, p. 3). LPMA claims that the 2% rate of inflation used by OPG in its business planning assumptions is not appropriate on the basis that it is higher than the 1.7% inflation rate used in the hydroelectric IRM formula (LPMA argument, p. 3). With respect to the inflation rate, OPG submits that LPMA has misinterpreted the evidence on the record. LPMA's concerns regarding PEO are addressed in Issue 6.5 (Section 7.5).

LPMA references interrogatory response (Ex. L-7.1-15 SEC-89) to cite OPG's assumed inflation rate for business planning purposes. OPG notes that this interrogatory response provided the inflation rate used to forecast ancillary services revenues, and it is not uniformly used across the business plan. OPG's response reads "for ancillary services revenues (from the provision of Reactive Support and Voltage Control) OPG derives its forecasts by escalating contracted rates by a forecast rate of inflation of 2%" (Ex. L-7.1-15 SEC-89, lines 22-24).

OPG does not utilize one uniform inflation rate throughout its business planning process, but rather, uses the most appropriate escalation factor for the cost being forecasted.[1] This may be based on escalation rates in line with contractual commitments, including collective agreements, or long-term inflation forecasts appropriate for a particular cost or revenue category, among other things.

As LPMA has misconstrued the evidence on this matter, the OEB should dismiss its request.

OPG received no other submissions on this issue and submits that the OEB should find that OPG's economic and business planning assumptions that impact the nuclear facilities are appropriate.

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[1] OPG's business planning and budgeting process is discussed in detail at Ex. A2-2-1.

2.3 Issue 1.3

Oral Hearing: Is the overall increase in nuclear payment amounts including rate riders reasonable given the overall bill impact on customers?

OPG did not receive any specific submissions under this issue number; however, OPG did receive a number of submissions under Issue 11.6 (Section 12.8) pertaining to OPG's rate smoothing proposal. OPG's response to those submissions is provided under Section 12.8.

3.0 RATE BASE

3.1 Issue 2.1 (see Issue 4.4)

Primary: Are the amounts proposed for nuclear rate base (excluding those for the Darlington Refurbishment Program) appropriate?

Please refer to Issue 4.4 (Section 5.4).

3.2 Issue 2.2 (see Issue 4.5)

Oral Hearing: Are the amounts proposed for nuclear rate base for the Darlington Refurbishment Program appropriate?

Please refer to Issue 4.5 (Section 5.5).

4.0 CAPITAL STRUCTURE AND COST OF CAPITAL

4.1 Issue 3.1

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

4.1.1 Proposed Capital Structure

OPG has applied for the recovery of its cost of capital based on a deemed capital structure of 49% equity and 51% debt. As discussed further below, a 49% equity ratio is reasonable, at least commensurate with OPG's risk and consistent with past OEB decisions. It represents the minimum ratio recommended by Concentric Energy Advisors ("Concentric"), and places OPG at the median relative to a group of comparable companies despite it being towards the upper end of the spectrum of risk profiles.

Those parties that have made submissions on the issue oppose OPG's request (OEB staff argument, pp. 5-11; QMA argument, p. 8; CME argument, section 2.0; CCC argument, pp. 25-27; SEC argument, paras. 3.7.1-3.7.4; EP argument, para. 8.29; VECC argument, p. 25; LPMA argument, pp. 5-8). Some, notably OEB staff, QMA and, to a lesser extent, CME, recognize that the deemed equity component of OPG's capital structure should increase. OEB staff propose a deemed capital structure of 47% equity – less than the 48% recommended by the expert they retained, The Brattle Group ("Brattle"). QMA agrees. CME argues that the equity ratio should not change but that, if it does, they agree with OEB staff's position.

Other parties, namely, SEC, CCC, LPMA, EP and VECC[2], argue that OPG's equity ratio should remain at 45%.

None of the parties' positions should be accepted by the OEB. To one degree or another, they all fail to acknowledge the evidence of the two independent cost of capital experts that testified. The expertise of these witnesses was unchallenged. They testified that OPG's risk has increased significantly relative to EB-2013-0321 such that an increase in OPG's equity ratio is warranted. Their assessment of the appropriate capital structure was compared and confirmed by reference to two separately selected (one by Concentric, the other by Brattle) proxy groups of companies. The expert evidence should be accepted by the OEB.

More fundamentally, however, parties' positions suffer from a fatal weakness – they are contrary to the OEB's own decision in EB-2013-0321, the undisputed rationale for that decision, and the position parties took in that case.

To put the matter bluntly, parties that object now argued then that OPG's equity ratio should be decreased from 47% to 45% on the basis that OPG had experienced an increase in the proportionate share of rate base related to hydroelectric facilities. The OEB agreed, confirming the view that hydroelectric assets are less risky to own and operate than nuclear assets (EB-2013-0321, Decision With Reason, p. 113); a conclusion the OEB had reached as far back as OPG's initial payment amounts proceeding EB-2007-0905. Now that the shoe is on the other foot, and OPG is spending many times more than it ever did on its hydroelectric facilities in

[2] VECC supports a range of 40%-45% (VECC argument, p. 25).

connection with the DRP, parties refuse to accept the logical implication of the OEB's decision and their past arguments. Their unprincipled positions should be seen as such and rejected.

4.1.2 OPG's risk has changed and increased

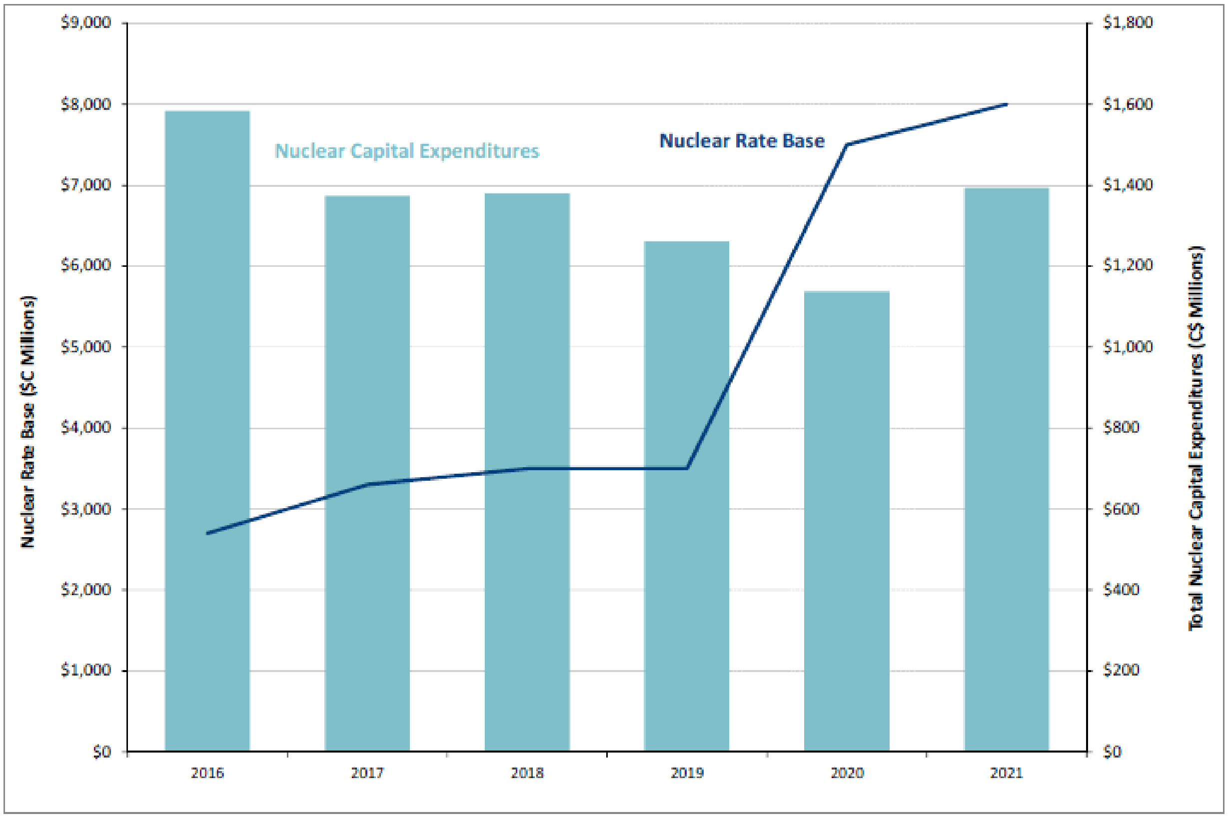
OEB staff accept that OPG's risk has increased and that its equity ratio should increase. As they say, "[n]ow, with the DRP (and to a lesser extent, PEO), OPG's portfolio is swinging back towards nuclear. A return to the pre-EB-2013-0321 equity thickness would therefore be warranted" (OEB staff argument, p. 6). In a sense, OEB staff are right – as recognized by the OEB in EB-2013-0321, nuclear generation assets are riskier than hydroelectric assets (EB-2013-0321, Decision with Reasons, p. 114) and OPG's proportion of nuclear assets is increasing. But, OEB staff's position overstates the similarities between OPG pre-EB-2013-0321 and now. In fact, OPG's portfolio is not simply "swinging back" to nuclear. Rather, through the IR term, OPG's proportion of nuclear assets will increase to higher than it has ever been. The DRP is simply a much larger capital project than anything undertaken in the Company's history, including by several multiples the Niagara Tunnel Project ("NTP").

Moreover, it is important to recognize that it is not simply the share of relative rate base that is changing but that OPG's expenditures associated with the DRP are increasing and there is significant risk associated with successfully executing this highly complex, mega-project.

As Concentric and Brattle testified, the cost of capital is both forward-looking and a current cost. Investors supply capital, and determine the return they require today, based on the returns they expect in the future. Although the first refurbished Darlington unit will not be brought into service until late in the IR term, OPG will be making substantial capital investments over the next five years that will require access to capital on reasonable terms (Ex. L-3.1-1 Staff-10). This significant spending is driven largely by DRP and is perhaps best seen by reference to Brattle's Figure 1.

Figure 1
Exhibit M3, Figure 1, p. 10

Figure 1: Illustration of Nuclear Capital Expenditures and Change in Rate Base



Sources: Ex. D2-1-2 Table 1 and Ex. C1-1-1

As Mr. Coyne (Concentric) testified in relation to this figure:

> MR. COYNE: …And that is that the risk that we're focusing on, yes, is measured by the change in nuclear rate base over time, as the Board has focused on the past, but from a financial perspective, the implications of the Darlington project are occurring today, and you can see that through the capital expenditures, which -- the bars there. So I believe what the Board should be doing is accommodating that profile and providing the company with the capital structure it needs to withstand the investments that we know will occur. You're right that there could be a delay and instead of 2019 or 20, it could be 2021. But that doesn't change the fundamental risk profile of the company as it's undertaking that investment. As the Board has indicated in the past, capital structure and the cost of capital is a forward-looking concept. … (Tr. Vol. 19, p. 33-34 (emphasis added)).

While purporting to acknowledge that the “DRP will materially change” OPG’s risk profile, OEB staff argue that the DRP risks have been overstated by Concentric (OEB staff argument, p. 6). They advance two sub arguments in this respect. The first argument is that the need for the DRP is established by O. Reg. 53/05 as is OPG’s right to recover its prudently incurred costs. A number of other parties make similar arguments with respect to O. Reg. 53/05 with EP going so far as to say that the stand alone principle does not apply (EP argument, para. 2.14).[3] The second argument advanced by OEB staff is that Concentric has not “adequately” factored in the exceptional level of planning undertaken by OPG in relation to the DRP.

Dealing with the first argument, the complete response to parties’ reliance on the provisions of the regulation, is that these were well known to the experts and were explicitly factored into their assessment of the appropriate capital structure. In other words, the provisions of the regulation, including those relating to need and prudence, are not a basis to reduce their recommendation. As Dr. Villadsen (Brattle) testified:

> MR. SMITH: And you were aware of the terms of Regulation 53/05?
>
> DR. VILLADSEN: Yes.
>
> MR. SMITH: And you were aware of the support that is reflected in those provisions for the Darlington Refurbishment Program?
>
> DR. VILLADSEN: Yes, I even cite that in my report.
>
> MR. SMITH: And I take it it's fair to say then that your recommendation of a 48 percent equity ratio is having regard to those provisions?
>
> DR. VILLADSEN: It has, yes.
>
> MR. SMITH: <u>And it would be wrong to conclude that the existence of those provisions should result in a lower equity ratio?</u>
>
> DR. VILLADSEN: <u>That is correct. As I had discussion with Mr. Shepherd, if you did not have these provisions we would have had a different recommendation.</u> (Tr. Vol. 19, p. 143, (emphasis added))

Moreover, it is wrong to say that “other utilities embarking on major spending programs typically do not have” the “regulatory safeguard[s]” that OPG has (OEB staff argument, p. 6). There is simply no evidentiary basis for this claim. In fact, Concentric testified specifically in

[3] The stand-alone principle is discussed further below.

relation to the regulatory and legislative protections that are afforded other nuclear mega-projects and that those projects would not have gone ahead without those protections (Tr. Vol. 19, pp. 5-7).

With respect to the second argument, Dr. Villadsen further specifically agreed that she was provided with all of the non-confidential evidence filed by OPG in the proceeding, and this would include OPG's evidence relating to the planning for the DRP (Tr. Vol. 19, p. 143). Likewise, Concentric testified that it similarly was aware of the relevant provisions of the Regulation and the extensive DRP related planning undertaken by OPG (Ex. C1-1-1, Attachment 1, pp. 20-21).

Similarly, SEC, VECC, and LPMA arguments that claim OPG's risk has not changed since EB-2013-0321 are without merit (SEC argument, para. 3.1.2; VECC argument, para. 3.1.68; LPMA argument, pp. 5-6).

Both SEC and VECC begin with a criticism of the independence of the expert witnesses (SEC argument, para. 3.2.2; VECC argument, paras. 3.1.6-3.1.8). Their complaints should be rejected out of hand. Neither party challenged the qualifications of the witnesses or argued that they should not be accepted by the OEB. VECC asked no questions of Concentric during its qualification, and counsel for SEC was not present in the hearing room during the qualification stage.

With respect to Brattle, whatever plans parties had to challenge Dr. Villadsen (if any), were abandoned when confronted with her considerable expertise. They should not be allowed to challenge her now. Moreover, their core complaint, that she has a "pro-utility focus" has no support in the record and is demonstrably wrong. As Dr. Villadsen testified, she has been retained by utilities, regulators, customer groups and here, by OEB staff (Tr. Vol. 19, p. 51, lines 15-25, and p. 58 lines 14-18).

As set out above, the most obvious problem with the argument that OPG's risk has not changed since EB-2013-0321 is its inconsistency with the OEB's decision in that, and earlier, cases. The OEB determined it was appropriate to reduce OPG's equity ratio on the basis of the addition of previously unregulated hydroelectric facilities and the NTP coming into service. If that was an appropriate basis on which to reduce OPG's equity ratio – which the OEB determined it was, given the evidence concerning the relative risk of nuclear versus hydroelectric assets in that case, this case and every other proceeding in which the OEB has considered the issue – the converse must also be true.

SEC, VECC, CCC, CME, and LPMA also argue that the DRP does not reflect a change in business risk because of the Capacity Refurbishment Variance Account ("CRVA") (SEC argument, paras. 3.3.31-3.3.39; VECC argument, para. 3.1.14; CCC argument, pp. 25-27; CME argument, paras. 10-11; LPMA argument, pp. 7-8). Their arguments proceed as though the CRVA were a new D&V account, and its relationship with the DRP is somehow different than other capital projects and the regulatory "protections" afforded are superior in some way. VECC explicitly, and wrongly, refers to the CRVA as a new variance account (VECC argument, para. 3.1.14). Of course, the account has existed since EB-2007-0905 and cannot be viewed as new in any sense.

Even if the account were new, the argument would have no merit. The CRVA captures prudently incurred costs. This fact is largely unremarkable. Traditionally, utilities regulated by the OEB and across North America, have been allowed to include in rate base their prudently incurred capital costs.

SEC suggests that because all prudent DRP costs will be borne by rate payers and imprudent costs "cannot" and "should not" be borne by ratepayers there can be no change in OPG's equity thickness (SEC argument, paras. 3.3.31-3.3.39). Taking this argument to its logical conclusion, there should be no risk differential between any regulated utility, assuming all such utilities are allowed to recover their prudently-incurred costs. This is inconsistent with past OEB decisions and how investors view risk.

In the same vein, it is wrong to say, as SEC does, that because of the CRVA, OPG does not "bear the normal risks of the project, those things that a reasonable planner could not have foreseen" (SEC argument, para. 3.3.34). OPG bears the same risk as other regulated utilities; its capital expenditures must be prudent. But, the risk associated with managing a project as large and complex as the DRP is greater than that experienced by a typical utility, including those utilities which make up the Brattle and Concentric proxy groups. What OPG does not bear – again like other regulated utilities – is merchant risk. But this risk was not factored into either Concentric or Brattle's assessments. If it were, their recommendation would have been a higher equity ratio (Tr. Vol. 18 p.29, lines 21-28; Tr. Vol. 19, p.119, lines 16-19).

4.1.3 Other arguments should be rejected

Proxy Group Comparisons Are Useful and Consistent with Accepted Regulatory Practice

OEB staff also argue that both experts' comparative analyses are of "limited assistance" (OEB staff argument, p. 9). SEC, VECC and CME also complain about the experts' proxy groups. Their complaints run contrary to the accepted regulatory approach to establishing the cost of capital, of which capital structure is a key component. Both experts included such an analysis as an important component of their work. As Concentric explained, use of a comparative analysis is a "common and well-accepted approach used in the determination of the cost of capital," in that it provides "adherence to the comparable investment standard" (Ex. C1-1-1, Attachment 1, p. 30).

However unique OPG is, that does not preclude the need to consider evidence from comparable utilities. Concentric and Brattle carefully screened their respective proxy companies to develop groups of companies that are most comparable to OPG. They then further considered the unique risk characteristics of OPG to determine where, within a reasonable range, OPG's equity ratio should appropriately fall. The application of sound analytical judgment is a common hallmark of comparative analyses. As cited by Concentric in its report, the NEB has found: "[t]o the greatest extent possible, comparable companies have to face similar business risks as the Mainline. If they do not, judgment needs to be applied to the cost of capital estimates to reflect business risk differences" (see, Exhibit C1-1-1, Attachment 1, p. 31, citing National Energy Board RH-003-2011 Reasons for Decision, TransCanada Pipelines Ltd, NOVA Gas Transmission Ltd., and Foothills Pipe Lines Ltd., March 2013, p. 165).

Similarly, parties point to an alleged general differential between Canadian and U.S. allowed equity ratios as a basis for their position. They further submit that the U.S. proxy group companies provide an insufficient basis for the determination of OPG's capital structure.

As Concentric explained, the report parties rely upon (Authorized Return on Equity for Canadian and U.S. Gas and Electric Utilities) is a general report concerning Return on Equity ("ROE") and common equity ratios for the principal Canadian electric and gas distributors. The Canadian data is a mix of investor-owned and crown corporations, while the U.S. data covers investor-owned utilities only. On the electric side, the data includes a mix of pure distribution companies as well as fully integrated utilities. As discussed below, this information cannot properly be used to make a downward adjustment in a U.S. proxy sample to apply to OPG (Tr. Vol.18, pp. 174-75).

First, the average of a broad and diverse set of U.S. and Canadian electric utilities does not provide a basis for an adjustment to a properly screened proxy group. As the OEB held in its Cost of Capital Report:

> The Board notes that Concentric did not rely on the entire universe of U.S. utilities for its comparative analysis. Rather, Concentric carefully selected comparable companies based on a series of transparent financial metrics, and the Board is of the view that this approach has considerable merit. (EB-2009-0084, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, p. 22).

Second, as Mr. Coyne explained, Concentric used the mean of the proxy group to establish its minimum recommended equity ratio, because OPG is riskier than the proxy group companies (Ex. C1-1-1, Attachment 1, p. 41; Tr. Vol.18, p. 176).

SEC's assertion that there are "structural differences in Canadian and U.S. regulated utilities" (SEC argument, para. 3.5.4) that necessitate an adjustment to Concentric's results has no evidentiary basis. Indeed, nowhere are these alleged differences even specified by SEC. As the NEB has stated, it "is not persuaded that the U.S. regulatory system exposes utilities to notable risks of major losses due either to unusual events or cost disallowances" (Ex. C1-1-1, Attachment 1, p. 44, citing National Energy Board, Reasons for Decision, TQM RH-1-2008 (March 2009), at p. 71). Likewise, the OEB has held, "The Board is of the view that the U.S. is a relevant source of comparable data" (Ex.C1-1-1, Attachment 1, p. 44, citing Ontario Energy Board, EB-2009-0084, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, p. 23).

Ultimately, Concentric and Brattle carefully screened the universe of North American utilities to develop comparison points that, in their view, more appropriately reflect the risk profile of OPG. While no proxy group will be perfectly comparable to the subject utility, a properly specified one provides an informed basis on which to assess OPG's capital structure.

Rating Agency Reports and IRM

Several parties point to the rating agency reports in support of their position against an increase in OPG's equity thickness. SEC, for example, concludes that, because the ratings agencies have no stated intention of downgrading OPG that "[n]either [S&P or DBRS] appears to be concerned" (SEC argument, para. 3.6.4). Here, again, parties' reliance is misplaced.

Their argument ignores the following. First, the credit ratings agencies, OPG and Brattle have all indicated that the Company's credit metrics will be pressured during the upcoming rate setting period. Second, the credit agency reports are premised on the assumption that "OPG will get most of its revenue requirements approved," including a 49% equity thickness (Tr. Vol. 19, pp. 145-146). Third, in relation to this and other arguments put forward by parties, such as the move to IRM, risk is measured in degrees. That OPG has not been downgraded does not mean that its risk profile has not changed. Nor does it mean that rating agencies view cost of service and incentive regulation the same way. As Concentric testified, agencies see IRM as an increased source of risk to utilities (see, e.g., Ex. L3.1-1 Staff-13; Ex.L3.1-1 Staff-17).

Stand-alone Principle

Some, including CCC and EP, argue that the relationship between the province and OPG breaches the principles of "stand-alone" regulation. In their submissions they point to provincial support through the actions of the Ontario Electricity Financial Corporation ("OEFC") in raising debt capital, the implicit support of the province in OPG's credit rating, and legislative and regulatory support for the DRP as a basis for questioning whether the stand-alone principle remains valid (CCC argument, pp.25-26; EP argument, paras. 8.5-8.18).

The OEB has already addressed this issue and been quite clear in its direction, both for OPG and all utilities the OEB regulates. With respect to OPG's capital structure, the OEB determined "The Board finds 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." The Board further concluded that it would apply the stand-alone principle in establishing the capital structure for the Company, noting that "[t]he stand-alone principle is a long-established regulatory principle," and that "Provincial ownership will not be a factor to be considered by the Board in establishing capital structure" (EB-2007-0905, Decision with Reasons, November 3, 2008, pp. 136-142, as at Tr. Vol.18, p. 6). The OEB reinforced this view unambiguously in its generic cost of capital report where it found "The Board also reiterated other policies, including that "the rate setting methodologies used by the Board apply uniformly to all rate-regulated utilities regardless of ownership. The determination of the rate-regulated utilities' cost of capital is no exception" (EB-2009-0084, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, p. 25, as cited at Tr. Vol.18, p. 7).

Understanding these OEB directions, Concentric and Brattle appropriately evaluated the capital structure on a stand-alone basis. But this is not tantamount to ignoring provincial ownership or involvement. As Dr. Villadsen explained:

> DR. VILLADSEN: The Board is not to pretend that there is no guarantee. The Board is to certainly take into account there is this regulation – 53/05, I believe it's called. And they're certainly to take that into account because you always take into account the regulatory environment in which an entity operates, because that determines its risk.
>
> However, the Board is also to look at what does that entity on a stand-alone basis with all the regulations, et cetera, that are in place, what is an appropriate equity structure for this company. (Tr. Vol. 19, p. 120).

Underscoring the OEB's well-founded principles of stand-alone regulation there are practical reasons why the intervenor arguments are untenable. If the inventor arguments were accepted, how would the OEB unwind the relationships between the Province and the entities it owns; how would it determine the risks and benefits of provincial ownership vs. private ownership; how would it assess the impacts of each legislative action; how would a shift in the regulatory approach affect costs and price signals to consumers? These practical considerations, among others, support the broadly adopted approach of stand-alone regulation, which allows the regulator to focus on the risks of the regulated entity, and not the risks of the shareholder(s).

The OEB Should Approve the Requested Change Now

LPMA suggests that if the OEB were to increase OPG's equity ratio, it should: (1) use a step-ladder approach whereby the equity thickness is not increased until 2020; or (2) approve a specific DRP related equity ratio (LPMA argument, pp. 6-8). Neither approach has any merit. With respect to the first, it disregards the undisputed evidence (discussed further above) that the cost of capital is a forward looking concept and the reality that large capital expenditures will be made in the near-term. The second, is contrary to the OEB's conclusion in earlier proceedings (for example EB-2010-0008), which rejected a technology specific approach to the cost of capital, let alone a project specific approach, as well as the evidence that OPG raises capital based on its overall risk profile.

4.1.4 Impact of potential disallowances

OEB staff conclude their submissions with an assertion that other disallowances they have proposed throughout their submissions (such as their proposed $50M annual compensation disallowance), "are not large enough to affect the capital structure analysis" (OEB staff argument, p. 11). Their claim has no evidentiary basis and should be rejected by the OEB. In fact, as set out above, the ratings agency reports are premised upon the approval of OPG's Application. In contrast, the OEB staff's proposed disallowances are summarized in Table 2 of their submission as having an impact of over $1.3B on OPG's revenue requirement over the five-year period (OEB staff argument, p. 3). Moreover, OEB staff did not put their claim to Concentric or even to Brattle, the expert they retained.

4.1.5 Conclusion concerning capital structure

The OEB has before it credible, reliable expert evidence to use in making its decision on the appropriate capital structure for OPG's prescribed facilities. The evidence is that OPG's risk has materially increased. This accords with common sense given the complexities and capital spending associated with the DRP in particular and the other business and regulatory changes OPG is undergoing; it also accords with the OEB's prior decisions relating to the relative risk associated with nuclear as compared to hydroelectric.

While the experts substantially agreed with one another, OPG submits that Concentric's opinion should be preferred. As outlined in OPG's Argument-in-Chief ("AIC"), with the recent change in the U.S. political landscape and the steps to unwind U.S. environmental legislation brought about by the previous Obama administration. Brattle's concerns regarding coal have, at least in part, been mitigated. Given that 49% was the minimum equity ratio Concentric would propose, OPG's request is reasonable and should be approved.

4.1.6 Rate of Return on Equity

OEB staff do not oppose OPG's proposed ROE of 8.78% for the nuclear facilities for 2017. Nor do they oppose the establishment of the Nuclear ROE Variance Account discussed further in Issue 9.8 (Section 10.8.3), although OEB staff do reserve the right to challenge the clearance of this account in a subsequent proceeding. Similarly, OEB staff do not oppose OPG's proposal as it relates to the ROE for the regulated hydroelectric facilities. To the extent other parties oppose OPG's position in relation to the ROE applicable to the nuclear and hydroelectric businesses, OPG's position is set out further in Issue 9.8 (Sections 10.8.3 and 10.8.4).

4.2 Issue 3.2

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

This issue is partially settled (Ex. O-1-1, p. 8). The parties have either agreed that, or not commented on, the assumed interest rates used to calculate OPG's proposed debt costs provided in Ex. C1-1-2 and Ex. C1-1-3 are appropriate on the basis of OPG's written evidence. Given that the aggregate debt costs relate to OPG's capital structure and rate base, which are unsettled issues, the parties further agreed that the settlement of this issue was subject to the application of the agreed interest rates to the eventual debt financed component of rate base as determined by the OEB.

LPMA, which supported the settlement of this issue (Ex. O-1-1, p. 8), was the only party to make submissions on this issue. It argues that the portion of rate base financed by short term debt be fixed at the 2016 level of 0.4%, rather than the 0.2% OPG has forecast. LPMA asserts that "OPG has provided no evidence as to why the short-term debt component should decline" (LPMA argument, p. 9).

To begin, LPMA's position is contrary to the settlement agreement. The agreement adopts OPG's written evidence on the issue of debt costs with the exception of any impacts of the eventual debt financed component of rate base, which will only be known once the OEB has rendered its decision in this matter. There is no open issue dealing with the breakdown of debt between long-term and short-term debt.

Moreover, it is simply wrong to say that there is no evidence on this issue. The record includes five pages of prefiled written evidence and tables relating to OPG's short-term debt facilities in Ex. C1-1-3, as well as an overview of debt rates and the components of debt in Tables 1-5 of Ex. C1-1-1. OPG answered 12 interrogatories under Issue 3.2 (four from LPMA), of which none requested any additional information about the short-term debt facilities. As evidenced in Ex. C1-1-3 Table 2, there is very little variability in OPG's short-term debt cost over the IR term.

Given that this issue is settled, and that OPG has provided ample evidence relating to its short-term debt costs, OPG submits that LPMA's request to modify the short-term debt component of rate base should be rejected.

5.0 CAPITAL PROJECTS

5.1 Issue 4.1

Oral Hearing: Do the costs associated with the regulated 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?

OEB staff submit that OPG has correctly identified the nuclear projects that meet the requirements of section 6(2)4 of O. Reg. 53/05 and therefore to which CRVA treatment applies. OEB staff submit 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. No other parties made submissions on this issue.

5.2 Issue 4.2 (see Issue 4.4)

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

Please refer to Issue 4.4 (Section 5.4).

5.3 Issue 4.3 (see Issue 4.5)

Oral Hearing: Are the proposed nuclear capital expenditures and/or financial commitments for the Darlington Refurbishment Program reasonable?

Please refer to Issue 4.5 (Section 5.5).

5.4 Issue 4.4

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

OPG provides its submissions on Issues 2.1, 4.2 and 4.4 concurrently.

OEB staff submit that they have no concerns with the methodologies used to calculate proposed rate base (including the net fixed/intangible asset portion and working capital) summarized by OPG at pages 15-16 of the AIC. No intervenors made arguments specific to Issue 2.1, although their submissions regarding nuclear capital expenditures and in-service amounts (as set out below) would impact rate base.

Similarly, OEB staff do not provide substantive argument or comments with respect to OPG's submissions on Issue 4.2. The parties' submissions and OPG's reply focus on matters within Issue 4.4, specifically, the approval OPG seeks for Nuclear Operations and Support Services in-service capital amounts.

OEB staff and intervenor arguments under Issue 4.4 generally fall into two categories: (1) questioning OPG's forecasted in-service capital additions; and (2) questioning whether OPG should be allowed to recover the full capital costs associated with two particular nuclear projects – the Auxiliary Heating System ("AHS") and the Operations Support Building ("OSB").

Regarding the first category, the in-service addition forecasts, OPG responds to main arguments of OEB staff and intervenors in two sub-categories: (A) whether OPG's forecast rate base and in-service capital additions should be updated to incorporate 2016 actual amounts (Section 5.4.1, part (A)); and (B) whether OPG's in-service capital forecasts for the IR term should be reduced (Section 5.4.1, part (B)). As OEB staff and intervenors advance a series of arguments on these matters, including a number of different calculations, OPG's response in this area is necessarily detailed.

On the AHS and OSB projects, OPG addresses the positions of OEB staff and the intervenors, for each project, in Section 5.4.2 below.

Finally, in Section 5.4.3, OPG addresses a variety of arguments raised by OEB staff and intervenors that do not fall into the above categories, including AMPCO's submission regarding capitalization of Darlington new fuel costs and OEB staff's contention that the OEB should identify certain projects now for further review and potential disallowance.

5.4.1 Forecast In-Service Amounts

A) Whether Forecast Rate Base and In-Service Additions Should be Updated for 2016 Actual Amounts

OPG is seeking approval of the prefiled in-service capital amounts related to Nuclear Operations and Support Services as explained in its AIC (AIC, Section 5.4) and set out in Table 5 of OEB staff's submissions (OEB staff argument, p.13). OEB staff submit that the basis for the OEB's approval should be the updated Nuclear Operations and Support Services in-service capital amounts provided in Undertaking J21.1, which shows the 2016 actual and the revised 2017-2021 forecast of in-service additions. The updated in-service amounts include the "cascading change," as SEC puts it, resulting from the lower than planned 2016 amounts (SEC argument, para. 5.2.5). OEB staff submit 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" as "the OEB typically requires the best available information to be used when forecasting […] in the absence of a true-up mechanism" (OEB staff argument, p. 18).

SEC and LPMA submit that OPG's nuclear in-service amounts should be set based on the actual 2016 amounts and the original prefiled forecast for 2017-2021 (SEC argument, para. 5.2.5; LPMA argument, p. 3). They argue that the updated forecast over the IR term should not be reflected because the underpinning updated project mix was not tested during the proceeding (SEC argument, para. 5.2.5; LPMA argument, p. 4). AMPCO similarly proposes that only the 2016 actual amounts, and not the cascading impacts, be reflected in the revenue requirement (AMPCO argument, paras. 79, 80 and 87).

Before responding to these submissions, OPG wishes to place Undertaking J21.1 in perspective. The undertaking was requested by SEC following an exchange with OPG witnesses:

> MR. SHEPHERD: You are asking this Board to order rates that are set based on an opening rate base for five years that is $205 million too high. And you know that, and they know that, and I'm asking you can you give us the rest of the information. Because otherwise, it seems to me, your revenue requirement has to go down by $100 million.
>
> MR. KOGAN: I think the way you're posing the question is exactly what I said a minute ago. Upon reflection, in line with what your line of questioning in fact is, we were going to go back and take a look at what a more comprehensive world view is, so we can consider properly all the timing effects and the continuities to the best of our ability, so that the best available information is in front of this Board.
>
> MR. SHEPHERD: I'm going to ask you either revise yesterday's undertaking, or perhaps more appropriately give a new undertaking today to update this table 1 from J14.1 to the forecast that you want the Board to rely on in setting rates, and the continuities that go with it, the rate base continuities that go with it. Will you do that?
>
> MR. SMITH: Yes, we'll do it. (Tr. Vol. 21, pp. 7-8).

In responding to that undertaking, OPG provided an updated rate base view that reflected the 2016 actual and the anticipated cascading effects on the 2017-2021 forecast in-service additions. The updated forecast was based on OPG’s operating circumstances at the time the forecast was prepared and therefore necessarily reflected changes in project mix. As noted at page 2 of Ex. J21.1, this forecast was “based on the 2017-2019 Business Plan, adjusted to account for 2016 actuals and subsequent changes in timing of in-service amounts over the 2016-2021 period”. This was the only forecast that was available for OPG to provide. No “other” hypothetical forecast that held the project mix unchanged from the 2016-2018 Business Plan, prepared over a year ago, exists or could have been prepared.[4]

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[4] OEB staff ask OPG to clarify whether OEB staff’s understanding is correct that the “updated forecast includes revised project cost estimates from the most recent business case summaries for the major capital projects” (OEB staff argument, p. 22). OPG confirms that OEB’s staff’s understanding is correct.

Undertaking J21.1 indicates that while the variance from the 2016 budgeted in-service amounts was in the order of $200M, over the entire 2016-2021 period, OPG expects <u>only a minor $1M increase in the total in-service amount</u> ($2,009M) compared to the prefiled evidence ($2,008M).

To ensure the integrity of updated rate base continuities provided in Ex. J21.1, OPG considered the impact of updated in-service amounts on depreciation expense. On the basis of the updated in-service additions and depreciation expense, OPG updated gross plant and accumulated depreciation values and rate base figures, as shown in Ex. J21.1, Attachment 2. The resulting rate base was approximately $30M lower, on average, over 2017-2021 reflecting shifts in in-service timing, while depreciation expense was approximately $8M per year higher on average, as discussed below. As shown in Chart 5.1 below, the net effect of these changes produces an <u>increase</u> of $60.6M in the total nuclear revenue requirement over the IR term. As OPG did not propose to update the forecast of in-service additions, OPG likewise did not propose to update the revenue requirement for this change. OPG submits that the original prefiled forecast remains reasonable.

Although OPG understands OEB staff's preference to update for best available information, OPG respectfully disagrees that the updates are necessary, or even desirable, in this case. Adjusting the revenue requirement for the updated in-service information, which came in late in the proceeding and would have increased the revenue requirement did not seem to be the best course of action at the time and, as OPG respectfully submits, is not the right course of action now.

Accordingly, SEC's claims that "the effect of OPG's position is that ratepayers will be overpaying in rates, and the company will be overcompensated" and that OPG had "refused to update" its requested relief are incorrect (SEC argument, paras. 5.2.1-5.2.2). The ratepayers will pay <u>less</u> under OPG's proposal.

If the OEB decides that it is appropriate to update the rate base for 2016 actual information as set out in Ex. J21.1, OPG urges it to reject SEC, LPMA and AMPCO's proposal to ignore the corresponding update to the forecast in-service additions over the IR term. Their proposal is unprincipled, selective and unfair. To ignore the updated forecast is to assume that <u>none</u> of the approximately $200M under-variance in 2016 capital in-service additions will be placed in service over the 2017-2021 period. OPG submits that this assumption would be unreasonable and contrary to the evidence on the record, as discussed below.

Intervenors ignore the fact that $70.3M in planned 2016 in-service capital was placed into service in the first quarter of 2017, in addition to the 2017 planned in-service amounts (Ex. J14.1). OPG submits that the fact that about one third of the 2016 variance could be placed in service in the first 12 weeks following the 2016 year-end is ample evidence that the entire 2016 variance will addressed over the five year period, in line with the Ex. J21.1 forecast.

As explained in the AIC (pp. 30-31) and as OEB staff put it, "assessing in-service additions over longer periods of time is a useful exercise [that] 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) and a more holistic understanding of overall capital additions to be gained" (OEB staff argument, p. 18). The intervenors' position ignores this interrelationship, effectively treating each year as independent and severable.

Fundamentally this position disregards the evidence on the multi-year nature of OPG's nuclear capital programs. OPG submits that cascading changes resulting from a project being moved, re-prioritized or delayed from one year to the next cannot be ignored. The efficient and effective execution of OPG capital program requires the ability to advance and defer projects when circumstances warrant. This is how capital portfolio work is managed and projects are completed.

In particular, in-service amounts are directly affected by OPG's portfolio management process, depending on organizational priorities and constraints, as well as project-specific circumstances (AIC, p. 31).[5] For example, the Asset Investment Steering Committee ("AISC") may defer or cancel a project as part of the portfolio management process so that a higher priority alternative project can be pursued, but the higher priority project may not come into service in the same time-frame as the project it replaced. On this basis, OPG continues to maintain that "a prudent approach would be to assess in-service forecasts and variances over the five-year period rather than on an annual basis" (AIC, p. 31).

[5] OPG's portfolio management process is discussed in detail in section 5.2.1 of the AIC.

In effect, the intervenors ask the OEB to set the revenue requirement on an internally inconsistent, highly selective basis. OPG submits that, from a fairness perspective, where possible, the revenue requirement should be set with a view to maintaining internal integrity and consistency of underlying assumptions and information. As the OEB observed in EB-2010-0008, "[t]he Board is reluctant to make selective updates to the evidence" (Decision with Reasons, p. 91). Intervenors are arguing not only to selectively update one element of revenue requirement (i.e. rate base) but to do so in relation to a single year of a six-year forecast (2016-2021). This approach is inappropriate and should be rejected by the OEB.

Parties rely on the argument that the project mix underpinning the updated in-service forecast was not detailed or tested in the proceeding. OPG submits that this is a non-issue. OPG's evidence contains a forecast of its anticipated project mix (Ex. D2-1-3). In the early years, many of the projects, particularly the large Tier 1 projects, are already underway (Ex D2-1-3, pp. 2-8). These projects will continue as part of the updated mix until complete, are well explained in the evidence, and have been explored at length through interrogatories.[6] For the smaller projects, and those in the later years that had yet to receive approval, the filing guidelines do not require, and the evidence does not provide, any detail. Thus intervenors already have the information on the larger projects and would not have received additional information on the smaller projects in any event.

In addition, this argument appears to be more opportunistic than principled. If the intervenors' had needed detail on the exact project mix to understand the updated in-service forecast, as they now seem to be claiming, OPG fails to see why they did not request it when they asked for the updated forecast of in-service additions.

In any event, the updated in-service forecast was requested at the end of the hearing, leaving little opportunity to test it. In contrast, OPG's prefiled evidence that provided a set of 2016-2021 forecasts using the 2016-2018 Business Plan has been thoroughly vetted and contains the most internally consistent information in this proceeding, which is why OPG proposes that it be adopted by the OEB for purposes of setting the revenue requirement.

[6] For example, Ex. J20.14 states that "there is no single material in-service amount that is forecast to move between 2017 and 2018."

Requests for Additional Information

In their reply submissions, OEB staff and LPMA request OPG to explain and provide more details on the average increase in depreciation expense in light of a lower forecast average rate base in Ex. J21.1 (OEB staff argument, p. 16; LPMA argument, p. 19).[7] OEB staff also request that OPG provide the annual revenue requirement (2017-2021) associated with each of the prefiled and updated forecasts per Ex. J21.1 (OEB staff argument, p. 18). These requests are addressed below.

The increase in depreciation between the prefiled and updated forecast of rate base is caused by a change in the project mix that results in relatively more in-service additions for the Pickering station over the period and relatively fewer in-service additions for the Darlington station and Nuclear Support Divisions.[8] An increase in forecast depreciation expense occurs as a result of the Pickering station having a much shorter accounting end-of-life date than the Darlington station (Ex. F4-1-1, p.3). As can be seen by comparing Ex. J21.1, Attachment 1, Table 1, "Net Plant" columns at lines 5, 12 and 19, to the same columns and lines of Ex. J21.1, Attachment 2, Table 3, the combination of the revised in-service additions and depreciation expense flows across years results in lower net plant rate base values (excluding asset retirement costs ("ARC")) in five of the six years of the 2016-2021 period, averaging at $29M/year lower (rounded to approximately $30M/year in Ex. J21.1 response).[9]

Chart 5.1 below provides the annual revenue requirement impact of nuclear net plant (excluding DRP and Asset Retirement Costs) associated with each of the prefiled and updated forecasts of in-service amounts per Ex. J21.1. The chart also provides the estimated annual revenue requirement impacts associated with OEB's staff's proposed in-service amounts

[7]LPMA's request is made under Issue 6.9.
[8]This can be seen by adding 2016-2021 in-service amounts for each of Darlington NGS, Pickering NGS and Nuclear Support Divisions lines found at Ex. J21.1, Attachment 1, Tables 2 and 3, col. (b) based on the prefiled evidence and Ex. J21.1, Attachment 2, Tables 4 and 5, col. (b) for the updated forecast. Based on the prefiled evidence, the totals are: $1,498.1M for Darlington, $419.2M for Pickering and $90.9M for Nuclear Support Divisions. The updated forecast totals are: $1,467.4M for Darlington, $464.0M for Pickering and $72.0M for Nuclear Support Divisions.
[9] Further details of the impact of updated in-service additions on gross plant rate base values and of updated depreciation expense on accumulated depreciation rate base values can be found by comparing the corresponding continuities found at Ex. J21.1, Attachment 1, Tables 2 and 3 (gross plant) and Tables 4 and 5 (accumulated depreciation) to Ex. J21.1, Attachment 2, Tables 4 and 5 (gross plant) and Tables 6 and 7 (accumulated depreciation). OPG applied the same methodologies to compute the updated values as it used in the prefiled evidence. These methodologies are summarized in the AIC under Issues 2.1 and 6.9 and further detailed in Ex. B1-1-1 and Ex. F4-1-1.

(discussed below), as requested by OEB staff at page 21 of their submission (footnote 60).[10] These impacts reflect income tax effects, including changes in capital cost allowance deductions.

Chart 5.1

Revenue Requirement Impact of Nuclear Net Plant (excluding DRP & Asset Retirement Costs)[1]

$M	2017	2018	2019	2020	2021	Total
Proposed - as shown in Ex. J21.1 Att 1	437.4	475.2	481.7	495.1	266.3	2,155.8
Updated Forecast - as shown in Ex. J21.1 Att 2	412.7	480.3	512.2	573.9	237.2	2,216.4
Board Staff Proposal	411.8	477.4	506.8	566.0	226.7	2,188.8

[1] Does not include the impact of regulatory tax loss carry backs / carry forwards, which will be assessed on a total revenue requirement basis. Such amounts have no cumulative effect on the total 2017-2021 revenue requirement but may result in increases/decreases for each respective year within the test period.

Under Issue 6.9 (Section 7.11), LPMA requests the OEB to direct OPG "to file detailed fixed asset continuity schedules for each year that reflect the changes" that the OEB may determine for in-service additions and "details of changes in the depreciation expense that would result from the capital changes" (LPMA argument, p. 19). OPG does not object to filing rate base continuity schedules in the format provided in Attachments to Ex. J21.1, if so directed by the OEB as part of the Payment Amounts Order process.

B) Should OPG's Forecast In-Service Amounts Be Reduced?

In addition to making submissions on whether the revenue requirement should incorporate the updated forecast in Ex. J21.1, OEB staff and intervenors argue for reductions in IR term in-service additions. OPG addresses these arguments under the subheadings below.

[10] OPG's calculation of revenue requirement impact of OEB staff's proposal on in-service additions yields different amounts than set out in the "Nuclear Op. Rate Base Additions" row of OEB staff's Table 2 (OEB staff argument, p. 3). OPG is unsure of how OEB staff calculated the amounts in that table.

OEB Staff and Intervenor Proposed Disallowances

OEB staff argue that OPG's updated forecast in Ex. J21.1 should be reduced by approximately $27.3M in each year of 2017-2021 period. They assert that "the updated forecast of in-service amounts is likely overstated", since "OPG has a vast number of projects" that are "competing for finite resources" and "[i]n 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" (OEB staff argument, pp. 19-20). The proposed aggregate disallowance over the IR term is $136.3M, or 7%, over the 2016-2021 period.[11]

SEC and LPMA go further in submitting that, in addition to reflecting the lower than planned actual in-service amounts for 2016, the OEB should reduce the original prefiled in-service capital additions forecast for each of 2017 through 2021 by 12.5% (SEC argument, para. 5.6.1; LPMA argument, p. 10).[12] SEC's proposed disallowance is based on: i) the 2010 to 2016 average variance between budgeted in-service additions and actual in-service additions; and ii) the approximate average variance between actual cost and the cost estimate in the first execution Business Case Summaries ("BCS") for OPG's capital projects (SEC argument, paras. 5.6.2-5.6.3). AMPCO goes further still in arguing for a 15% annual reduction to original prefiled forecast in-service amounts, based on its characterization of cost and schedule project performance results, the same 12.5% historical variance, and its review of Projects and Modifications performance (AMPCO argument, para. 87).[13] EP does not provide detailed recommendations, but argues that the OEB should approve "some level of rate base disallowance, particularly on the AHS and OSB projects, among others overseen by the P&M organization" (EP argument, p. 41).

OPG notes that the effective disallowances proposed by SEC, LPMA and AMPCO are much higher than the indicated percentages, as they do not allow for the updated 2017-2021 forecast

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[11] OEB staff calculate this reduction as the difference between the $206.6M capital addition shortfall in 2016 and the $70.3M in-service amount that was moved to 2017 as of March 31, 2017 (and is already in service). OEB staff contend that this reduction should be divided equally in each year 2017-2021 ($27.3M each year) to reflect the "cascading impact of the 2016 shortfall" (OEB staff argument, p. 21).

[12] Both LPMA and SEC's 12.5% reduction proposal is drawn from Table 8 of OEB staff's submission, which contends that OPG has over forecasted in-service additions over the 2010-2016 period by more than $190M, or 12.5%. OPG addresses OEB staff's Table 8 in detail below.

[13] Paragraph 49 of AMPCO's argument states that it proposes disallowances only for the years 2017 - 2019, which directly contradicts the request in paragraph 87 of its argument.

while reflecting the lower actual 2016 in-service amounts. When properly taken as a percentage of OPG's original prefiled total forecast for 2016-2021 (or the virtually unchanged updated total forecast in Ex. J21.1), SEC and LPMA's overall proposal in fact represents a reduction of 20% relative to OPG's request, while AMPCO's proposal would result in a reduction of 22.5%. These proposed disallowances are in addition to SEC's unspecified "further reductions to account for the lack of efficiency and productivity initiatives in the test period" (SEC argument, para. 1.3.9(b)) and the expansion of the stretch factor to include non-DRP capital amounts advocated by SEC, AMPCO and others (see Issues 11.3 and 11.4 at Section 12.5).

In OPG's view, the OEB should reject these proposals. They misstate or misinterpret the evidence, or ignore it completely.

OEB Staff's Table 8 and Historical In-Service Amounts

OEB staff contend that OPG's updated forecast is overly optimistic and fails to reflect the necessary delays from the 2016 in-service additions variance (OEB staff argument, pp. 19-20). OEB staff did not challenge the accuracy of OPG's updated forecast directly. Rather, OEB staff's proposed reduction rests solely on their analysis of historic Nuclear Operations capital in-service additions variances for years 2010-2016 presented in Chart 5.2, OEB staff's Table 8 (OEB staff argument, p. 20).[14] As intervenors rely on OEB staff's analysis of the historical variances, Table 8 in OEB staff's argument is reproduced below.

[14] OPG notes that OEB staff's argument is effectively for a reduction equal to the amount of under-variance in the 15-month period ended March 31, 2017. This position is not greatly different from the intervenors' position that the known variance to the end of 2016 should be reflected in the approved rate base but corresponding changes to the subsequent years' in-service additions should be disregarded. Therefore, OEB staff's argument suffers from many of the same shortcomings as outlined in Section 5.4.1.

Chart 5.2
Table 8 from OEB staff Argument, p. 20

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

OPG agrees that this table is informative. However, it respectfully submits that parties have not interpreted the variance amounts correctly.

The table shows that in the 2010-2015 period, there were three years with positive variances and three years with negative variances, for a net total positive variance of $14.1M. This is consistent with the observation in the AIC that a shift of in-service amounts from one year to the next is not unusual and can lead to cyclical variances as changes in operational priorities, project schedules or other factors contribute to projects being deferred, delayed and sometimes advanced in the normal course of business (AIC, p. 31). As noted above, OEB staff make a similar observation (OEB staff argument, p. 19).

The problem with OEB staff and intervenors' analysis of Table 8 is their failure to recognize that the addition of the 2016 negative variance of over $200M to the previous six years is the <u>sole</u> driver of the $190M (or 12.5%) negative variance for the seven-year period. Said differently, the entire historical analysis is skewed by a single data point – the most recent year where, due to shifts in timing, less capital was placed in service than planned and a large negative variance from forecast resulted. The evidence shows that this situation has already begun to substantially reverse in the first three months of 2017 (Ex. J14.1).

Contrary to parties' claims, the historical variances do <u>not</u> provide an appropriate basis for a disallowance. Effectively, the parties' proposed disallowances are based on the 2016 variance alone. However, the 2016 variance is due to timing of projects coming into service, and is not a question of OPG's prudence or viability of the projects themselves. OPG submits that the OEB should not deny cost recovery simply because some projects are coming in later than forecast and should therefore reject the proposed disallowances.

OEB staff's Table 8 illustrates a few additional points not acknowledged by the parties. It shows that OPG placed in service over $50M, or 17.5%, more in Nuclear Operations capital over 2014 and 2015 than the forecast approved by the OEB for that period in EB-2013-0321. As well, the table shows that, although below budget, the 2016 actual in-service amount is substantially higher than any other historical year, which is not surprising given increasing levels of capital expenditures over the last several years (discussed below).

Nuclear Operations Capital Plan – Capital Expenditures and In-Service Amounts

SEC and AMPCO's submissions examine the pattern of OPG's capital expenditures and their relationship to in-service additions. Tables comparing capital expenditures and in-service additions for 2010-2021 are found at paragraphs 58 and 59 of AMPCO's submission, respectively.[15] OPG agrees that a proper analysis of capital expenditures and in-service additions is instructive. Unfortunately, similar to their analysis of OEB staff's Table 8, the parties draw a number of incorrect conclusions from this information, as discussed below.

Historical Capital Spending Compared to Budget

SEC claims that OPG spent less than 60% of its planned capital in 2016 (SEC argument, para. 5.3.2). SEC references Ex. J14.1 as the support for this statement, but this cannot be correct because that undertaking addresses in-service additions, not capital spending. The parties appear to be confusing in-service amounts with capital expenditures, the latter being a more accurate measure of work performed. In fact, OPG's actual 2016 capital expenditures did not exhibit the level of variance seen in 2016 in-service additions. For further context, OPG notes that actual Nuclear Operations capital expenditures have exceeded forecasts in each of the three preceeding years, 2013, 2014 and 2015 (Ex. D2-1-2, Table 4).[16]

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[15] AMPCO and SEC's analyses of Nuclear Operations capital expenditures and in-service additions are based on the original prefiled forecast for 2017-2021.

[16] "Board-approved" figures for 2014 and 2015 shown in Ex. D2-1-2, Table 4 do not include projects reclassified to Nuclear Operations as part of the DRP scope review through the RQE process, while the "Actual" figures include them. However, even after adjusting for this, Nuclear Operations capital exceeds forecast in each of 2014 and 2015.

Forecast Capital Spending Compared to Historical Period

AMPCO observes that OPG's forecast 2017-2021 Nuclear Operations capital spending as set out in the prefiled forecast is approximately 20% higher than the actual capital spending over 2010-2015, effectively questioning the achievability of OPG's planned capital program (AMPCO argument, p. 12).[17] OPG submits that the OEB should place little weight on this comparison. A more relevant observation is that capital spending has been steadily increasing over the last number of years, from $148.1M in 2011 to $314.8M in 2015, and that the average forecast spending over the IR term of $259.4M is actually somewhat lower than the spending in each of 2014 and 2015. The main drivers of the increasing trend in capital expenditures include the following, as outlined in OPG's evidence (Ex. D2-1-2, pp. 3-4 and AIC, p. 27):

- Additional requirements due to regulatory programs such as the Darlington Integrated Implementation Plan and those projects initiated to address the regulatory requirements resulting from the 101 "Fukushima Action Items" assigned by the CNSC;
- Additional capital funding required to replace obsolete and/or life-expired plant equipment at Darlington, in line with benchmarking against industry peers that shows OPG's capital expenditures were historically below the industry median; and
- Certain projects being reclassified to the Nuclear Operations project portfolio a result of the RQE review of the appropriate DRP scope.

A more representative period for examining historical capital spending is 2013-2015. Including 2010-2012 in the comparison would be inappropriate because the main drivers of current capital spending as set out above did not apply in that timeframe. When the 2017-2021 forecast capital expenditures are properly compared to the 2013-2015 period, the forecast is in line with historical results, as shown in Chart 5.3 below.

Chart 5.3
Capital Expenditures 2013-2015 and 2017-2021

CAPITAL EXPENDITURES 2013 to 2021										
	2013	**2014**	**2015**	**2017**	**2018**	**2019**	**2020**	**2021**	**2017-2021**	**2013-2015**
									Average	**Average**
Nuclear Operations	201.2	292.7	314.8	279.0	258.0	282.4	278.5	199.3	259.4	269.6

[17] SEC incorrectly claims that the planned level of Nuclear Operations capital spending is much higher than historical levels (SEC argument, para. 5.3.2). Ex. D2-1-2, Table 1, line 1 shows that actual Nuclear Operations capital expenditures in both 2014 and 2015 exceed the forecast spending in any of the five years in the IR term.

Rather than representing a 20% increase, 2017-2021 capital spending represents about a 4% decrease compared to 2013-2015. This also addresses OEB staff's concern that OPG may not have sufficient resources to execute its capital plan – the plan is very much in line with OPG's capital spending over the last several years (OEB staff argument, p. 19).

Forecast In-Service Additions Compared to Historical Period and to Capital Expenditures

AMPCO points out that OPG's average annual in-service additions for Nuclear Operations are proposed to increase from $175M over the 2010-2015 period to $292M over the IR term (AMPCO argument, para. 58), while SEC observes that the same forecast represents an increase of 36% compared to the 2014-2016 period (SEC argument, para. 5.3.1). Putting aside the relative merits of specific historical periods selected for comparison, these observations are directionally correct, but are not surprising. This pattern simply reflects the period of higher capital expenditures that OPG has been experiencing, as discussed under the preceding heading.

AMPCO recognizes that in-service additions are driven by capital expenditures; however, its specific analysis again falls short. Specifically, AMPCO compares annual Nuclear Operations in-service additions as a percentage of annual capital expenditures over the 2010-2021 period (based on prefiled forecast of in-service additions) (AMPCO argument, para. 58). As that percentage increases from an average of 81% over 2010-2015 to 112.5% over 2017-2021, AMPCO implies that this is evidence of OPG over-forecasting in-service additions. This is incorrect.

As AMPCO's table shows, Nuclear Operations in-service amounts have been consistently below capital expenditures during 2013-2015 (AMPCO argument, para. 59). At the same time, capital expenditure in 2014 and 2015 increased substantially over the prior year (Ex. D2-1-2, Table 1). This increased capital spending will ultimately come into service and when this happens, in-service amounts will exceed capital expenditures (assuming, as is the case here, that capital expenditures are not forecast to continue increasing year over year). This is evident from the fact that in-service additions were $243M lower than capital expenditures over the 2013-2015 period (in-service additions of $565.3M compared to capital expenditures of $808.7M, based on AMPCO's table at paragraph 59), while the opposite pattern is true for the

2016-2021 period. Forecast in-service additions for 2016-2021 exceed capital expenditures by $306M (in-service additions of $1,956.5M compared to capital expenditures of $1,650.2M) (AMPCO argument, para. 59).[18]

The above pattern arises because OPG's nuclear projects span multiple years. AMPCO's ratio analysis of a given year's in-service additions to that year's capital expenditures is therefore incomplete, as it does not consider capital expenditures in past years that come in-service in later years.

In summary, OPG has experienced a period of increasing capital expenditures (for reasons outlined in Section 5.4.1), and these expenditures are now finding their way into in-service additions. Furthermore, as outlined in Issue 6.2 (Section 7.2), capital expenditures although increasing still remain within the top quartile benchmark. Capital expenditures levels are now stabilizing and, indeed, are expected to begin to decline toward the end of the IR term as Pickering approaches its planned end of commercial operations. SEC and AMPCO's analyses of capital expenditures and in-service additions fail to recognize this pattern and therefore cannot be used to support any disallowances.

Individual Project Spending and Schedule Variances

SEC and AMPCO advance a number of arguments that attempt to link their allegations of systemic capital project overspending and poor project management practices to the appropriate level of forecast in-service additions. At the core of these parties' arguments is the claim that spending more on capital does not necessarily translate into completing more work (AMPCO argument, para. 59; SEC argument, para. 5.3.3). Before turning to the specific reasons why this claim is wrong, OPG submits that, in any event, these arguments are not an appropriate basis for a reduction of forecast in-service additions. They are not based on the amount and timing of forecast in-service additions. Rather, they are arguments that the OEB should adopt a "presumption of imprudence." As such, they should be rejected.

On this matter, OEB staff's submission helpfully states:

[18] Said differently, the construction work in progress for Nuclear Operations capital has been increasing over the last several years, but is expected to decrease during the IR term.

> 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 druing 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 nuclear operations capital project[s] at rebasing to determine whether incremental costs incurred are prudent and should be properly included in rate base on a go-forward basis. (OEB staff argument, pp. 32-33).

Addressing claims of imprudence at the time of rebasing is consistent with the approach the OEB has taken in the past and, OPG submits, should continue to be followed for Nuclear Operations and Support Services capital.[19] Reducing forecast in-service additions based on a "presumption of imprudence," as argued by AMPCO and SEC, is unwarranted.

SEC says that its calculation of the 11.72% average capital project overspending supplies additional justification for the proposed 12.5% disallowance to forecast in-service capital, because the two numbers are "close" (SEC argument, para. 5.6.3).[20] In addition to not being a valid basis for reduction of future in-service additions as discused above, SEC's calculation is skewed by a few large projects. Specifically, as pointed out by Mr. Lawrie during the oral hearing (Tr. Vol. 14, pp. 59-62), the vast majority of OPG's projects shows small, positive and negative variances. OPG submits that the AHS and OSB projects (discussed further below) are the main contributors to SEC's forecast capital project variance. When those projects are removed, OPG is actually 3% below budget on the remaining projects and is only 4% above budget for Tier 1 projects (calculated based on Ex. JT2.16).

Intervenors assert that OPG is "always behind schedule", and its in-service forecast amounts should be reduced due to OPG's historic project schedule performance.[21] As set out below, OPG submits that the intervenors' presentation of schedule delays is misleading and does not take into account the practical realities of project execution.

SEC further contends that the total in-service date variance of projects identified in EB-2013-0321 (with in-service dates in 2014-2015) amounts to delays of 424 months, or an average of 17 months per project (Tr. Vol. 14, p. 86; SEC argument, para. 5.3.9). OPG submits that these

[19] OPG also addresses this concept under section 5.4.3.
[20] AMPCO makes a similar argument in paragraph 72 of its submission.
[21] See LPMA argument, p. 56; SEC argument, paras. 5.3.9-5.3.14; AMPCO argument, paras. 70-72.

figures ignore that minor project delays may be extended significantly where projects cannot be completed within a given outage window.

Mr. Lawrie discussed this concept, addressing the determinative effect outages can have on in-service dates:

> So, for example, if a program is scheduled to be executed in a particular outage, those outages are well-defined and locked in. <u>If we have challenges with getting the project ready for installation, material availability, design completion, we won't threaten the outage by trying to force that project into the outage at the last minute. We'll make a conscious decision to defer it to the next planned outage, and that's a case where we would be subject to the date moving</u>. (Tr. Vol. 14, p. 90 (emphasis added)).

One example of this is the Darlington Fukushima Phase Beyond Design Basis Event Emergency Mitigation Equipment Project ("Darlington Fukushima Equipment Project"). This project was originally scheduled to come in-service in December 2015, but is now projected for December 2017 (Ex. D2-1-3 Table 7, Line 25). As explained at page 16 of Ex. D2-1-3, the implementation date for this project was amended due to the rescheduling of its outage window. While intervenors use this 24 month delay to bolster their total and average in-service date variance calculation, they ignore the practical reality that such construction work must be delayed because it can <u>only</u> take place during a scheduled outage window.

On an undertaking like the Darlington Fukushima Equipment Project, if a timeline is pushed back for minor reasons, work <u>must</u> wait until the next outage window (which could be two or three years later depending on the facility). Put simply, OPG will not force a project into an outage to meet an in service date. While this may significantly skew in-service timelines, it does not – contrary to what intervenors contend – confirm poor project scheduling performance.

Intervenors' submissions on this point also ignore situations where a project is up and running – and the full business benefit has been achieved – but OPG chooses not to close-out the project due to internal operational requirements. For example, OPG's chiller replacement project (#33631), carried a planned completion date of 2009 (with units being installed and placed in-service shortly thereafter), but OPG did not formally close out the project because it was not fully satisfied with the product received from the vendor (Tr. Vol. 15, pp. 45-46). As Mr. Lawrie explained:

> MR. LAWRIE: So I do believe that although it sounds impressive that we have 102 month delayed project where in fact we did get the business benefit, but we wanted to ensure that we had the absolute quality established before we closed out the project. (Tr. Vol. 15, pp. 45-46 (emphasis added)).

It is worth repeating that OPG's recent project management improvements (see Ex. D2-1-1, Section 3; AIC, pp. 24-26) will enhance scheduling accuracy in addition to cost estimation accuracy moving forward. Ensuring the company has the right level of definition and planning completed before progressing to each gate will give OPG a higher confidence level when scheduling in-service dates (Tr. Vol. 14, pp. 86-87).

The scenarios above help demonstrate the flaws that bias intervenor claims regarding OPG's historical project schedule performance. Project in-service dates can be delayed for a myriad of reasons, and each project must be reviewed on a case-by-case basis. For these reasons, OPG submits that the intervenor assertions regarding OPG project scheduling performance are unreliable and should be set aside.

AMPCO argues that the increase in the number of superseding BCSs necessarily suggests that OPG's project performance is lacking. OPG submits that it is incorrect to assume that an updated BCS equates to deficient project management. OPG fully expects to update its BCS as a project transitions from definition to execution, or from a partial BCS to a full execution BCS. AMPCO appears to incorrectly assume that only an increase in project cost will result in a superseding BCS. In fact, a superseding BCS can be reflective of the movement between one of the above-mentioned phases as well as for variances above a threshold (Ex. J15.2, Attachment 2, p. 4). OPG submits that such movement is part of OPG's gated process for project management and is indicative of a prudent organization, continuously trying to refine and improve its project cost estimates.

Insufficient Productivity

SEC submits that the productivity initiatives that OPG is planning are inadequate and focus mainly on production (SEC argument, para. 5.4.2). SEC contends that higher production does not necessarily benefit ratepayers as much as lower capital or OM&A costs, and that "ratepayers do bear the consequences of high OM&A and capital costs" (SEC argument, para. 5.4.3). This argument is difficult to follow. To the extent SEC refers to productivity initiatives that are built into the forecast cost or production levels used to set payment amounts, clearly ratepayers benefit from both. A higher production forecast results in lower payment amounts and if OPG fails to meet its production forecast, it receives no payment for the shortfall. To the extent OPG's cost are higher than forecast, absent a true-up mechanism, customers do not pay more. Instead, OPG's earnings decrease.

SEC isolates a quote from Ms. Carmichael's testimony on OPG's productivity initiatives at Tr. Vol. 14, pages 10-11, to support its suggestion that OPG is only focused on production and ignores OM&A costs. Ms. Carmichael expands on this statement later, however, emphasizing that OPG's focus on production initiatives is not directed at the expense of focusing on costs. As summarized by Ms. Carmichael, OPG continues to focus on cost reduction as part of continuous improvement, that the stretch factor will be an added incentive to reduce costs, and that past initiatives (e.g. business transformation) were successful in reducing costs:

> MS. CARMICHAEL: As I mentioned, the fleet-level ones or the high-level initiatives focus on production. We are always looking at ways to reduce our OM&A costs, particularly now that we have stretch factor. We will be challenged to do that.
>
> Historically, though, if you look at where we've been, we've focused a lot on our cost initiatives, so we did things like Pickering amalgamation to reduce costs at Pickering. We did days-based maintenance to reduce sort of labour needs and not have to have night shifts, and that enabled to us save costs -- costs associated with that.
>
> We have done business transformation, which essentially reduce 2,700 people across the organization to have a sustainable cost structure. So we focused a lot on cost initiatives in the past and widespread, very difficult ones, because business transformation was a very difficult cost initiative.
>
> And now we're at that state where we believe we're steady state base OM&A. We still are looking and endeavouring to do better, and that's why we are proposing the stretch factor, but again, most of our initiatives now are around sustaining our production, making sure we meet our production plan, because that is where we've got our biggest financial risk of our organization, and that's where we need to focus. (Tr. Vol. 14, p. 13 (emphasis added)).

While SEC's submission makes no specific proposals on the "cost focused productivity initiatives" that OPG should adopt, OPG has identified past and ongoing initiatives on the record that have been or are being implemented to improve the performance of its project management function (and therefore impact project execution). Past initiatives include adopting and Engineering, Procurement and Construction contracting strategy, allowing OPG to optimize its resources and efforts on project oversight (Ex. D2-1-1, pp. 5-6). Through a primary competitive vendor selection process, OPG achieved a reduction in trade labour rates and improved contract terms and conditions (Ex. D2-1-1, p. 5). In addition, there are five main continuous improvement initiatives designed to improve project management performance currently underway, as summarized at Ex. D2-1-1, pages 6-8:

- Centre of Excellence
- Identification of Appropriate Contracting Strategy
- Implementing new approaches to improved ESMSA vendor project execution performance
- Improved OPG staff project management and oversight capabilities
- Improving project cost and schedule predictability

OPG also notes that its costs associated with the Projects and Modifications ("P&M") organization (as further discussed below) in base OM&A decline from $7.4M in 2013 to a forecast of $4.0M in 2021, reflecting continuous improvement in project management oversight (Ex. F2-2-1, Table 1).

Based on the above, OPG submits that it has incorporated sufficient productivity into its nuclear OM&A and capital budgets and that SEC's proposal for in-service additions reductions on account of productivity should be rejected.[22]

OPG's Project Management – Projects and Modifications Organization and Gated Process

OEB staff and intervenors also make extensive submissions on OPG's project management efforts, including the record of its P&M and OPG's "gated process". OEB staff's submissions on this topic focus mainly on the AHS and OSB projects and are addressed in detail at Section 5.4.2.

SEC cites the number of projects it claims were delayed (and by how long), arguing that the OEB should have no confidence in OPG's ability to forecast projects over the five-year IR term (SEC argument, paras. 5.3.9-5.3.11). Using SEC's numbers, LPMA criticizes OPG's project

[22] For additional discussion on OPG's stretch factor proposal, see Issue 11.3 (Section 12.5).

management efforts, contending that OPG will not be able to meet its forecast in-service schedule (LPMA argument, p. 10). SEC, EP and AMPCO offer extensive criticism of OPG's project management performance and the P&M group and also take issue with OPG's enhanced and more rigorous gated process (SEC argument, paras. 5.3.15 to 5.3.26; EP argument, pp. 38-40; AMPCO argument, pp. 24-26).[23] SEC exemplifies the parties' criticisms of the gated process arguing that: i) it was not implemented early enough; and ii) it will only affect certain projects expected to go in-service during the IR term (SEC argument, paras. 5.3.16 to 5.3.17).

OPG has explained in great detail the company's considerable efforts to improve its project management functions and gated process (see Ex. D2-1-1, Section 3; AIC, pp. 24-26). As such, OPG will not repeat these submissions here.

OPG does not deny that its P&M group faced challenges during the early stages of OPG's campus plan projects. The P&M group is undertaking a total project portfolio of $1.1B over the three-year period from 2015-2017. When a company attempts to construct such a large portfolio with so many moving parts, issues will inevitably arise and lessons will be learned (Ex. J7.3, Attachment 1, p. 3).

OEB staff and intervenors base their concerns with the effectiveness of the P&M group primarily on three reports:

- OPG's internal *Project Controls Audit – Project & Modifications Group (March 9, 2016)*" (Ex. J7.3, Attachment 1) ("Internal P&M Audit");
- OPG's *Nuclear Oversight Audit Report – Project Management (OPGN NO-2015-022 T6) (March 13, 2015)* (Ex. JT1.8, Attachment 2) ("Nuclear Oversight Audit"); and
- Burns and McDonnell and Modus Strategic Solutions' ("BMcD/Modus") *2nd Quarter 2014 Report to the Nuclear Oversight Committee of OPG's Board of Directors (May 13, 2014)* (Ex. L4.3-Staff-72, Attachment 4) ("2014 Q2 Report").

A review of these three reports, which are so heavily relied upon by the intervenors, shows that they do <u>not</u> portray the negative picture that parties suggest. Intervenors emphasize the

[23] It is difficult for OPG to be certain it has fully responded to all of AMPCO's specific points regarding OPG's project management efforts because AMPCO's references are vague, missing altogether or incorrect. For example, AMPCO provides numerous references to "Staff #72" (i.e., Ex. L-4.3-1 Staff-72) that do not specify a page or even an attachment number. This interrogatory response has 30 attachments that total more than 700 pages.

negative findings and ignore the positive ones. For example, they ignore the following findings from the most recent report, the March 2016 Internal P&M Audit:

- The P&M Group is in the process of implementing several changes to their project management framework to align with the revised Nuclear Projects governance, including adopting more up-front planning activities prior to execution; and
- The P&M group's project management team were found to be highly knowledgeable concerning project management principles and how to deploy them on their projects. (Ex. JT1.8, Attachment 2, p. 5).

Regarding the 2014 Q2 Report prepared by BMcD/Modus – undoubtedly the main reference that OEB staff and intervenors use to question OPG's project management efforts – OPG respectfully submits that the *Supplemental Report to Nuclear Oversight Committee 2nd Quarter 2014 (June 26, 2014)* ("Supplemental Report") (Ex. J15.3, Attachment 1) effectively supersedes the findings of the earlier report. OPG discusses the Supplemental Report in great detail under Section 5.4.2 in the context of the AHS project.[24] The Supplemental Report puts the findings of the 2014 Q2 Report in perspective and, overall, acknowledges the efforts of OPG, including the P&M group, to improve the company's project management processes.[25]

In OPG's view, prudent organizations remain aware of the need for continuous improvement, develop strategies to make improvements, implement these strategies, and monitor whether the desired outcomes are delivered. Prudent organizations also make adjustments where needed during the implementation process to maximize each improvement initiative. OPG submits that it has done exactly this by, among other things, changing its P&M leadership, revising its Engineering, Procurement and Construction ("EPC") contracting model and entering into the ESMSA contract agreements (AIC, pp. 24-26, section 5.2.1).

AMPCO proposes that OPG be directed to undertake an additional audit of its P&M project controls in time for the mid-term review and provide a status report at that time (AMPCO argument, p. 28). OPG submits that this proposal should be rejected. This type of micromanagement is fundamentally at odds with the OEB's incentive regulation regime and, in

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[24] The table provided at pp. 19-21 of the Supplemental Report provides a summary of the "P&M Recovery" initiatives that the group was implementing to address and correct the issues raised in the 2014 Q2 Report (Ex. J15.3, Attachment 1).

[25] BMcD/Modus confirm that they are satisfied with the P&M group's actions and commitments to providing responses to their recommendations (Ex. J15.3, Attachment 1, p. 12).

particular, the OEB's conception of a five-year IR term. Moreover, AMPCO's proposal is outside of the proposed scope of the mid-term review (discussed further under Issue 11.5 at Section 12.7) and, if adopted, would turn that limited review of production into a forensic examination of selected aspects of OPG's business.

5.4.2 Nuclear Operations Capital – AHS, OSB and Prudence of Incremental Costs

For two projects, AHS and OSB, OPG's proposed in-service additions exceed the amounts forecasted in EB-2013-0321. OEB staff and intervenors have recommended reductions to the proposed in-service additions based on claims that OPG imprudently managed these projects. In this section, OPG explains why these claims are incorrect, at odds with the evidence and should be rejected.[26]

OEB staff submit that the OEB should order a permanent reduction to the capital costs associated with the AHS project of an estimated $28M and the OSB project of an estimated $7M. OEB staff submit this is appropriate due to OPG's imprudent management of these projects. EP supports OEB staff's proposal that the OEB should approve some level of rate base disallowance, particularly on the AHS and OSB projects, among others overseen by the P&M organization (EP argument, para. 5.18).[27]

CME and SEC use similar arguments, but recommend larger disallowances (CME argument, p. 21; SEC argument, para.5.6.5). CME contends that the OEB should decline to include in rate base the entire incremental cost of completing the AHS and the OSB projects while SEC argues that the OEB should disallow 50% of the incremental costs of the OSB, and disallow the entire incremental amounts for the AHS project (*Id.*). LPMA agrees with the OEB staff and SEC submissions on these issues, including on the range of the appropriate disallowance (LPMA argument, p. 4).

OPG respectfully submits that the OEB should accept OPG's proposed nuclear in-service capital amounts for the AHS project and OSB project as submitted.

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[26] The AHS is very near to completion with an updated final in-service date of October 2017, while the OSB project was in service as of October 2015 (Ex. JT2.16, p. 1).
[27] EP claims that reclassifying these projects from the DRP has somehow limited the opportunity to review them (EP argument, para. 5.17). The extensive review both projects received in this proceeding demonstrates that this claim is incorrect.

Beginning with AHS, the first execution business case for the project estimated a total project cost of $45.6M and the revised final cost of the project is estimated to be $107.1M (Ex. JT2.16). The forecast in-service amount is $98.7M based on the updated evidence (Ex. JT2.16). As OEB staff point out, a portion of the total cost of the AHS project relates to removal and decommissioning costs, and this portion is not reflected in the requested in-service amount.

While the parties reference a few documents to support their recommended disallowances (including the Internal P&M Audit and Nuclear Oversight Audit) they base the majority of their submissions on statements made in BMcD/Modus' 2014 Q2 Report (Ex. L-4.3-1 Staff-72, Attachment 4). While that report does highlight the challenges OPG's management faced on the AHS project, the fact remains that it is a point-in-time assessment made in May of 2014. As mentioned above, BMcD/Modus subsequently published their Supplemental Report in June of 2014 (Ex. J15.3, Attachment 1). The Supplemental Report actually references the 2014 Report at the beginning of its executive summary, stating that "it is important that the comments and recommendations that BMcD/Modus made with respect to the Campus Plan Projects in our 2Q 2014 Report dated May 13, 2014 are viewed with proper perspective" (Ex. J15.3, Attachment 1, p. 1). While OPG referenced this report in its AIC, in light of the fact that both OEB staff and the intervenors rely so heavily on the 2014 Q2 Report, OPG believes it is important to present additional detail on the Supplemental Report.[28]

While acknowledging "mistakes made by management", the executive summary of the Supplement Report addresses a number of points made in the 2014 Q2 Report, including:

> Project & Modifications' ("P&M") early management of the pre-requisite Campus Plan Projects, and in particular the D2O Storage Facility and Auxiliary Heating Steam system ("AHS"), exposed some critical project management gaps. <u>The initial cost estimates for these two pre-requisite projects were poorly developed, thus the cost variances now reported are being compared to poorly developed</u>

[28] At footnote 306 of SEC's submissions (SEC argument, p. 65), SEC questions the validity of the Supplemental Report, alleging that its "independence… was and is put into question" based on the fact that OPG management and counsel had provided comments." This statement is inaccurate. While SEC cites EB-2013-0321, Ex. JT3.8 to support its claim, it neglects to address the cover letter to that exhibit, in which BMcD/Modus confirms that they "did not receive any instructions regarding the June 26, 2014 Report". Regarding the two emails from OPG management and counsel that were produced by BMcD/Modus', they confirmed that those messages were "the only written recommendations that came forward from OPG" for discussion, that they "rejected most of management's recommendations and those that were adopted were minor", and that the communications "resulted in no substantive changes to the June 26, 2014 report" (EB-2013-0321, Ex. JT3.8, Attachment 1, p. 1).

> baseline budgets. Senior management addressed these problems by making changes at the Project executive level, installing new leadership with proven ability, and altering the management model. While these pre-requisite projects will cost more than initially anticipated, and continue to present schedule threats to Refurbishment, P&M's new leadership has this work and other Campus Plan Projects on a much more predictable course. Moreover, many of the cost variances appear to be scope based, i.e. OPG is getting more value albeit for a higher cost. (Ex. J15.3, Attachment 1, p. 2 (emphasis added)).

It then confirms the fact that OPG has worked to implement "lessons learned" from the early stages of the AHS:

> Both P&M and the DR Team have learned early and essential lessons from D2O Storage and AHS and are using these lessons to modify OPG's management plan for the entire Refurbishment Project. In particular, P&M is abandoning the "hands-off" contractor oversight strategy that was initially prevalent and is adopting an active management role, while the DR Team used these lessons to increase contractor accountability. (Ex. J15.3, Attachment 1, p. 3).

Most importantly, the Supplemental Report later supports OPG's position that the majority of cost increases for AHS is due to expanding scope and flawed initial estimates. Indeed, the Supplemental Report argues that the increased budgets are reflective of the true project costs:

> It is important to note that we believe that the majority of the cost increases with D2O Storage and AHS are due to maturation of these projects' scope definition, scope management, unforeseen subsurface conditions or flawed estimates. In other words, the increased budgets are simply reflective of the true project costs had they been estimated properly at the outset**...** Our criticism in the 2Q 2014 Report stems mainly from the fact that the project management strategy originally employed by the P&M organization did not match the chosen commercial strategy, as both the multiple-prime delivery method and target pricing requires that OPG be fully engaged as the contract manager of the Refurbishment Project. As a result, P&M did not have the tools to determine the "true" costs of the project from the outset and communicate those costs to the Board of Directors. (Ex. J15.3, Attachment 1, p. 17 (emphasis added)).

This point is further supported later on – that if P&M had the tools to determine the "true costs" of the AHS project and correctly labeled it as having a Class 5 maturity level, the project could very likely have avoided any "overruns":

> Based on these practices, the budgets initially approved by the Board for D2O Storage ($108M) and AHS ($45.7M) were not sufficient for the planned scope of work. Moreover, had P&M appropriately classified these two project's cost

> estimates at a Class 5 (-50% to +100%) maturity level, it is very likely that these projects could have entirely avoided an overrun. (Ex. J15.3, Attachment 1, p. 18 (emphasis added)).

The Supplemental Report also confirms that P&M recognized these issues in 2014 and was already "actively working to negate any repeated issues in the estimating of the remaining work" (Ex. J15.3, Attachment 1, p. 18).

It is clear that the Supplemental Report provides further insight to the issues raised in the 2014 Q2 Report (and subsequently by OEB staff and intervenors in their submissions). As such, the parties' focus on the 2014 Q2 Report does not provide an accurate picture, either of the true cost of the AHS project or OPG's subsequent efforts to improve project management. While OPG has acknowledged challenges (Tr. Vol. 12, p. 165), the fact remains that the company went to great lengths to address these issues, further developing its portfolio management processes, creating additional checks and balances and generally improving its project performance.[29]

OEB staff's argument appears to support the notion that the revised estimates better reflect the true project cost, agreeing that "costs exceeding an artificially low original estimate should not necessarily be, in the absence of other issues, considered imprudent", and that "simply because the final cost of a project is higher than a poorly developed estimate does not mean all incremental spending is automatically imprudent" (OEB staff argument, p. 27).

Based on the submissions above OPG believes that the AHS project disallowances proposed by OEB staff and the intervenors are excessive and unreasonable and should be rejected. They bear no apparent relation to OPG's prudence in managing the AHS project. The reductions they propose appear arbitrary based on individual parties' approximate estimates of what portion of incremental costs should be attributed to project mismanagement versus estimation and scoping issues.

OEB staff and intervenors advance similar arguments in support of their disallowance of OSB in-service amounts as for AHS and OPG's response is similar as well. As set out below, OPG

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[29] As mentioned above, see AIC, pp. 24-26 and 28-29 for a summary of these efforts.

submits that many of the conclusions reached in BMcD/Modus's Supplemental Report regarding the AHS project are directly applicable to the OSB project.

OEB staff's acknowledgement that costs exceeding an artificially low original estimate should not necessarily be, in the absence of other issues, considered imprudent, applies to OSB with equal force. As set out in OPG's AIC, while the OSB will cost more than originally estimated, this is primarily due to the fact that the project baseline measures were established before completing engineering (AIC, p. 28). The observed cost variances largely relate to inadequate scope in the initial estimates, which were not indicative of the projects' true costs. As explained during the hearing, with respect to the OSB project:

> MR. LAWRIE: We believe these are the true costs of the work that was performed that turned out to meet the requirements that were identified through the process. Early estimates, before the design requirements are fully understood, were reported at a higher confidence level than they should have been. But the actual work performed, in terms of refurbishing the OSB and the requirements needed to make that building meet its -- performance requirements for the staff using it, and the end result we got is value and it met the requirements, and those costs were what were incurred. (Tr. Vol. 12, p. 166).

OPG describes the root causes of the OSB project cost variance, and OPG's extensive efforts to address each concern, in detail at Ex. L-4.2-1 Staff-25. These efforts include:

- <u>The cost estimate at the time of the full release approval was inadequate</u> – The full release approval for the project was approved prior to completing detailed engineering. OPG subsequently updated the project approval process to ensure that the required deliverables for each approval gate were completed and that the project had an appropriate class of estimate for the approval gate.

- <u>Engineering assumptions were not validated prior to the full BCS approval</u> – OPG allocated insufficient contingency for invalidated design assumptions. OPG has since established a collaborative front-end process and augmented its gated process (as described in Ex. L-4.4-15 SEC-43) to address validation inadequacy and engineering assumptions on future projects.

- <u>Changes from the preliminary engineering requirements were identified</u> – Changes were identified during a detailed engineering review to meet code requirements <u>and reduce future maintenance costs for the heating, ventilation, and air condition systems.</u>

- <u>The amount of power available from the station was a limited concern</u> – The amount of power available from the station proved limited, requiring costly upgrades to the power supplies. This, in turn, necessitated modifications to use lower power consumption LED lighting. While this increased project costs, it will result in lower OM&A costs in the future.

- Scope additions beyond OPG's control – The project required scope additions to address discovery issues, including mold and asbestos.

OPG expands on the OSB cost variance in Ex. D2-1-3, Attachment 1 (the Project Over-Variance Approval for the OSB project, or "OSB POVA"). OEB staff and intervenors refer to this document, and specifically OPG's recognition of project management concerns, as evidence of mismanagement.[30] OPG submits that the OSB POVA helps provide additional context as to how the variance arose, and confirms that the majority of the variance relates to initial estimation concerns and scope additions.

As explained in the OSB POVA, "Of the $14.4M contract cost variance, $11.7M is attributed to the EPC Contractor underestimating the effort required to complete the contract scope" (Ex. D2-1-3, Attachment 1, p. 1). More specifically, this variance was attributable to: i) the design subcontractor completing revisions to the incomplete design packages; ii) increased equipment and construction work to compete design revisions; and iii) the contractor being behind schedule as compared to the original plan (*Id.*).

The OSB POVA goes on to explain that the remainder of the $2.7M variance was attributable to required contract scope changes. These included (Ex. D2-1-3, Attachment 1, Tab 1, pp. 1-2):

- upgrading motor control electrical distribution equipment;
- additional cabling and hardware to support changes to IT and telephone requirements;
- changes to furniture and building layout requirements for occupants;
- upgrading to fire separation of civil structures;
- repairs to exterior walkways and soffits; and
- other minor architectural, mechanical and electrical changes.

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[30] See OEB staff argument, p. 30; SEC argument, p. 64; AMPCO argument, p. 31; CME argument, p. 26.

The OSB POVA also explains that $2.6M of specific contingency was included in the execution-full release to cover the above OPC contract issues (Ex. D2-1-3, Attachment 1, Tab 1, p. 2). This contingency was then partially drawn upon due to the aforementioned discovery and remediation of mould and the hiring of a commissioning agent to ensure an efficient building start-up, minimizing the impact of commissioning issues on the overall project (*Id.*).

The details above provide context and help highlight many similarities between the AHS and OSB projects. Both projects suffered from poorly developed initial cost estimates (meaning current cost variances are compared against poorly developed baseline budgets). The majority of cost increases associated with each project were due to these estimation issues and scope increases typical of large scale building projects. OPG went to great lengths to improve project management processes for both projects. And, just as BMcD/Modus confirmed for the AHS project, OPG submits that the end result is an OSB project that reflects the "true project costs had they been estimated properly at the outset".

Like the AHS project, OPG believes that the OSB disallowances proposed by OEB staff and the intervenors are arbitrary. They either propose that the entire incremental variance amount should be disallowed or estimate a portion of the variance they believe is attributable to project mismanagement, providing no evidence to justify their proposed reduction. [31]

Based on the above, OPG submits that the OEB should not accept the parties' proposed disallowances for the OSB project. The OEB should accept OPG's proposed nuclear in-service capital amount for the OSB project as submitted.

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[31] OEB staff, supported by VECC and EP, submit that 50% of the incremental capital costs (as between the original estimate and the final amount) should be disallowed from inclusion in rate base, which it estimates at $7M (OEB staff argument, p. 30). SEC also asks the OEB to disallow 50% of the incremental cost, which it estimates to be $8.8M (SEC argument, para. 5.5.4). AMPCO submits that the entire incremental cost should be disallowed (AMPCO argument, p. 31). CME does as well, less removal and decommissioning costs (CME argument, p. 28). LPMA submits that the disallowance should be 100% of whatever portion of the incremental costs that the OEB deems to be the result of imprudent management and states that it agrees with OEB staff and SEC's submissions (LPMA argument, p. 4).

5.4.3 Nuclear Operations Capital – Other Issues

Darlington New Fuel

As stated by AMPCO, in 2019, OPG proposes to capitalize $15.3M for Darlington new fuel with the return to service of refurbished Unit 2, and expense $15.3M in 2020. AMPCO submits that, for regulatory purposes, no portion of new fuel should be capitalized and the full amounts should be expensed, claiming that OPG confirmed it does not have a past practice to capitalize new fuel (AMPCO argument, p. 13). That is not an accurate characterization of OPG's response. The response actually indicates that the practice is consistent with US GAAP, and that it was used by the former Ontario Hydro, stating:

> OPG does not have a past practice with respect to new fuel loads because the return to service of refurbished Darlington Unit 2 will be the first instance of a full new fuel load 2 being loaded into a defueled reactor of an OPG-operated nuclear station since OPG's 3 inception. OPG understands that the practice was used by the former Ontario Hydro. (Ex. L-6.3-1 Staff-111, p. 2 (emphasis added)).

AMPCO submits that OPG's evidence to support this capitalization proposal is weak, the total amount should be expensed and that, accordingly, the in-service amount in 2019 should be reduced by $15.3M (AMPCO argument, p. 13). No other party challenged OPG's accounting for the capitalization of new fuel.

While AMPCO claims that OPG's evidence in support of its accounting is "weak," it failed to offer any alternative accounting evidence, nor did it cross examine OPG on its response in the interrogatory that this approach is consistent with US GAAP (Ex. L-6.3-1-Staff-111, p. 2). As interrogatory Ex. L-6.3-1 Staff-111 states, the portion of the cost of the new fuel load corresponding to the unused fuel expected to be remaining in the reactor at the end of its life is eligible to be capitalized because it is considered to be a cost arising from operating the unit over its entire life (i.e., the unused fuel arises at the end of the unit's life as a result of the ongoing refueling during the life). Capitalization of this amount at the outset of the unit coming online allows the value of the unused fuel bundles to be allocated systematically over the unit's life.

The alternative to OPG's proposal is recovery of 100% of new fuel in payment amounts as an expense, as AMPCO appears to prefer. This would increase the 2017-2021 revenue requirement and result in the first-ever instance, to date, of divergence between OPG's audited fixed asset values for financial accounting purposes and for regulatory purposes. OPG submits that this is not warranted in light of the relatively small revenue requirement impact, consistent with the OEB's findings in EB-2010-0008 Decision with Reasons. Faced with a similar issue, related to depreciation assumptions, the OEB stated at page 110 of that decision: "changing the assumptions […] has a relatively small revenue requirement impact which does not warrant the difficulties inherent in having separate accounting and regulatory accounts."

For the reasons listed above, OPG submits that the OEB should accept its Darlington new fuel proposal as filed on the record.

Identifying Projects for Further Review

OEB staff also submit that there are a number of other projects that will fully, or partially, come into service during the IR term that may include costs that were imprudently incurred. Consequently, OEB staff argue, 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). OEB staff go on to cite two specific projects: the Project Controls Audit of the P&M group (the 2016 Audit) – the Darlington Class II Uninterruptable Power Supply Replacement and the Fukushima Phase 1 Beyond Design Day Event Project ("Darlington Class II" and "Fukushima Phase 1", see OEB staff argument, p. 32).

OPG believes that identifying projects for potential future disallowances is unwarranted and unnecessary in light of the OEB's ratemaking processes and procedures. As OEB staff recognize, the OEB will have the opportunity to review cost variances on nuclear operations capital projects at rebasing to determine whether incremental costs incurred are prudent and should be properly included in rate base on a go-forward basis.

Indeed, OEB staff submissions appear to acknowledge the challenges inherent in identifying projects in advance. After naming Darlington Class II and Fukushima Phase 1 as potentially problematic (citing the 2016 Audit and potential significant cost overruns), OEB staff go on to state that Darlington Class II is "in the very early stages" and Fukushima Phase 1 "is still not near completion" (OEB staff argument, p. 32). Finally, they submit that, no disallowances should be made for these two projects "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" (OEB staff argument, p. 32).

Because the OEB has the ability to assess cost variances at rebasing, and in light of OEB staff's admission that 1) it is too early, and 2) it does not have enough information to properly assess or propose a disallowance for the two projects in question, OPG submits that "identifying" these two projects – or in fact any projects – for further review at future rebasing is unnecessary.

5.5 Issue 4.5

Oral Hearing: Are the proposed test period in-service additions for the Darlington Refurbishment Program appropriate?

5.5.1 Introduction

OPG has undertaken prudent and reasonable steps to plan and execute the refurbishment of Darlington's Unit 2 and related Early In-Service projects, Facilities & Infrastructure Projects ("F&IP") and Safety Improvement Opportunities ("SIO") initiatives. Using industry best practices, OPG has completed extensive planning to establish high confidence cost and schedule baselines. The program and project management structures that OPG has implemented are designed to ensure contractor and employee safety, quality of work to enable 30 or more years of operations for Darlington, drive cost and schedule performance, provide necessary oversight and appropriately manage change.

Below, OPG responds to the primary issues raised by OEB staff and intervenors. For the most part, parties did not challenge OPG's development and planning of the Unit 2 refurbishment or its approach to execution. Many of their submissions relate to the appropriate level of contingency to include in the approved costs, combined with the level of review required in a subsequent proceeding to dispose of the CRVA. Taken together, parties' positions on these issues, if adopted, would inappropriately alter the use of the CRVA and establish it as a mechanism to rehear this proceeding in the future and to defer revenue requirement. This approach would repurpose the CRVA and use it as a substitute for the Rate Smoothing Deferral Account ("RSDA"). Efforts by OEB staff and intervenors to alter the use of the CRVA in this manner should not be accepted by the OEB.

The appropriate focus of the OEB's determination in this proceeding is a revenue requirement reflecting the approval of the in-service amount of $4,800.2M for the Unit 2 refurbishment and $377.2M for the F&IP, SIO and Early In-Service projects. In this regard, OPG has applied best industry practices for a megaprogram, and has been transparent in its planning, development and execution of the Unit 2 refurbishment and the F&IP, SIO and Early In-Service projects. It has provided extensive prefiled evidence, including expert and third party reports and, when asked, disclosed internal documentation,[32] all of which go to establish that the in-service amounts sought are reasonable and should form part of the IR term revenue requirement.

5.5.2 Reply by Issue

Below OPG addresses each of the main issue raised by parties.

Regulatory Scope

GEC relies upon an incorrect interpretation of section 6(2)4 of O. Reg. 53/05 to assert that approximately $2.0B of DRP Unit 2 forecast costs are precluded from recovery (GEC argument, pp. 16-17). SEC, CME, CCC and ED put forward a similar view (SEC argument para. 4.2.5; CME argument, para. 146; CCC argument, p. 4). GEC's interpretation and application of section 6(2)4 are incorrect. It has parsed the words of the section in a manner that fails to acknowledge, much less address, the OEB's consistent interpretation and application of this provision. GEC also fails to consider the application of related provisions of O. Reg. 53/05, which provide a clear indication of the intended meaning and proper interpretation of section 6(2)4, and of the OEB's ultimate jurisdiction.

GEC, SEC, CME and CCC pin their narrow interpretation on one word – "were" – in the context of the phrase "costs were prudently incurred and that the financial commitments were prudently made." Ignoring all the aspects of section 6(2) and the regulation as a whole, GEC concludes that the reference to costs that "were incurred" means that the OEB can only consider costs

[32] SEC asserted that OPG took a "back the truck up" approach as to document disclosure (SEC argument, para. 1.2.4). However, OPG notes that many of those documents were disclosed as a result of the specific interrogatory requests and technical conference undertakings posed by SEC to disclose "all reports, analysis, opinion, evaluations and/or assessments" or other types of documents with respect to broad topics (see, for example, Ex. L-4.3-15 SEC-14; Ex. L-4.3-15 SEC-16 part c; Ex. L-4.3-15 SEC-17, part c; Ex. L-4.3-15 SEC-20, part b; Ex. L-4.3-15 SEC-22; Ex. L-4.3-15 SEC-34, part e). On multiple occasions and to the extent possible, OPG tried to narrow the request to key documents.

retrospectively and cannot consider forecast costs prospectively. Based on the same flawed reasoning advanced by GEC, parties assert that the OEB cannot approve an in-service amount for DRP on the basis of forecast costs in this Application.

Below OPG demonstrates that GEC's position would have the OEB interpret section 6(2)4 in a manner that is (i) at odds with the OEB's interpretation of section 6(2)4 in every other payment amounts proceeding and OPG's D&V account applications, and (ii) inconsistent with other provisions of O. Reg. 53/05. At no time has the OEB ever interpreted section 6(2)4 in the manner proffered by GEC, SEC, CME and CCC. Nor did OEB staff advance this interpretation in their submission.

The intent of section 6(2)4 is to provide OPG with the right to recover all of its prudent capital and non-capital costs and firm commitments incurred to increase the output of, refurbish or add capacity to a generation facility (hereafter referred to collectively as "Section 6(2)4 Costs"). Nothing is this section limits the OEB's ability to approve recovery of forecast cost in the ordinary course of setting revenue requirement, even if the actual cost is subject to subsequent review. In the event the actual Section 6(2)4 Costs vary from forecast, then, subject to prudence, the OEB must make provision for the recovery of actual amounts and has established the CRVA for this purpose. The recovery of actual Section 6(2)4 Costs, no more and no less, is the only limitation imposed on the OEB under that section.[33]

Ontario Reg. 53/05 was amended to specifically reference the "Darlington Refurbishment Project" in section 6(2)4, but this did not change the meaning of section 6(2)4 meaning or its application. To the extent the OEB includes forecast refurbishment costs in the revenue requirement, it will have concluded these costs are reasonable and will produce just and reasonable rates. For DRP, as for other Section 6(2)4 Costs, if OPG achieves its forecast exactly, then it recovers its actual in-service amounts through OEB approved rates. If costs differ from the forecast, whether higher or lower, OPG will seek to recover or refund the

[33] As the OEB wrote in the EB-2007-0905 Decision with Reasons, "The Board notes that when it is intended that the Board ensure OPG recover certain amounts, O. Reg. 53/05 is explicit. For example, Section 6(2)4 obligates the Board to ensure OPG recovers nuclear refurbishment costs." (p. 79). It then went on to approve the CRVA to ensure that actual costs were recovered, stating: "In light of the obligation imposed on the Board by Section 6(2)4, the Board accepts that a variance account is required for the period beginning April 1, 2008 and authorizes OPG to establish the capacity refurbishment variance account." (EB-2007-0905, Decision with Reasons, p. 123).

difference through the CRVA subject to the OEB's prudence determination. This is the manner in which the OEB has interpreted and applied Section 6(2)4 since OPG's first payment amount proceeding, EB-2007-0905.

In EB-2007-0905, OPG sought the recovery of OM&A costs relating to planning and preparation for possible nuclear refurbishments as part of OPG's test period Project OM&A forecast. In that proceeding, OEB staff made a submission on the meaning of the word "incurred" in section 6(2)4, arguing that the OEB need not include any forecast amounts in the revenue requirement, and that the OEB can only permit recovery when OPG actually spent money on activities falling under section 6(2)4. The OEB agreed with the OEB staff's interpretation of "incurred" and indicated that it would consider delaying recovery if there was little assurance that forecast amounts would actually be spent during the test period. However, the OEB found that OPG would incur costs for these section 6(2)4 eligible activities in the test period and accepted the inclusion of the forecast amounts in the revenue requirement (EB-2007-0905, Decision with Reasons, p. 38).

Using similar reasoning, the OEB recognized that Section 6(2)4 Costs for capital projects can be included in rate base on a forecast basis. In EB-2007-0905, the OEB determined that two hydroelectric projects, the NTP and the Sir Adam Beck 1 GS – Unit 7 Frequency Conversion Project, were covered under section 6(2)4 (EB-2007-0905, Decision with Reasons, p. 44). While the forecast amounts for the NTP were not addressed because the project was not scheduled to come into service during the test period, capital costs for the Unit 7 Frequency Conversion Project, which had a scheduled in-service date during the test period, were added to rate base on a forecast basis as proposed by OPG (*Id.*).

As noted above, in EB-2007-0905, the OEB established the CRVA to address any variance between approved forecast Section 6(2)4 Costs and actual costs. This concept of the CRVA is captured in successive Payment Amount Orders as follows:

> The Capacity Refurbishment Variance Account was originally approved in EB-2007-0905. This account shall continue and will record variances between the actual capital and non-capital costs, and firm financial commitments incurred to increase the output of, refurbish or add operating capacity to a prescribed generation facility referred to in O. Reg. 53/05 section 2 and <u>those forecast costs and firm financial commitments reflected in the revenue requirement approved by the Board</u> for 2014 and 2015. This account shall continue to

> include assessment costs and pre-engineering costs and commitments.[34] (emphasis added).

Parties have ignored the historical application of section 6(2)4, which has uniformly been applied as described above. The fact that the section was amended to specifically reference the DRP does not change its intent or meaning. Other than a greater level of specificity, there is no difference between DRP costs and other Section 6(2)4 Costs.

Likewise this interpretation is consistent with the regime established in O. Reg. 53/05 as a whole. Section 6(2)12 of O. Reg. 53/05 contemplates that for the purposes of approving payment amounts under section 78.1, the OEB shall approve, on a 5-year basis for the first 10 years of the deferral period, revenue requirement and the amount of the approved revenue requirement to be deferred. This section contains two key aspects. First, a revenue requirement will be determined for all nuclear facilities, which includes Darlington's prospective capital in-service amounts and OM&A. Second, there will be a deferral of the revenue requirement in the deferral period, which, as defined by O. Reg. 53/05, is the period between January 1, 2017 and when the DRP ends (O. Reg. 53/05, section 0.1). Clearly, the requirements established by O. Reg. 53/05 contemplate both the determination of a forward-looking revenue requirement that includes DRP costs and the deferral of a portion of that revenue requirement during a period that ends with the completion of the DRP. If, as proposed by GEC and others, the DRP costs were not to form a part of the revenue requirement in the period, there would have been no reason for the regulation to provide for deferral and certainly no reason to link the end of the deferral period to the end of the DRP. Section 6(2)4 must be read in the context of the entirety of O. Reg. 53/05 and not in isolation as proposed by GEC.

As indicated above, the purpose of section 6(2)4 is to impose an obligation on the OEB to permit recovery of actual Section 6(2)4 Costs that are prudent. It in no way limits the OEB from its normal functions of reviewing forecast costs and establishing a revenue requirement, which is inherently prospective. Under this reading of section 6(2)4, the OEB's fundamental obligation to establish a revenue requirement and to set just and reasonable rates remain intact. Based on

[34] Payment Amounts Order, EB-2013-0321, Appendix G, p. 10. The same wording is included in the Payment Amounts Orders in EB-2007-0905 and EB-2010-0008.

the foregoing, OPG submits that the OEB can approve the DRP costs proposed by OPG as in-service additions as part of the revenue requirement for the IR term.

Based on an incorrect interpretation of section 6(2)4, SEC further submits that the regulation's language means that reasonable costs approved by the OEB in payment amounts are a "placeholder" until finally determined (SEC argument, para. 4.2.9). Likewise CCC also believes that the approval of DRP costs is inherently interim (CCC argument, p. 4).

OPG believes that the use of the terms "placeholder" or interim are not appropriate when describing the nature of the OEB's approval of DRP costs and the associated in-service amount for Unit 2. The OEB's determination of a reasonable forecast of DRP costs and Unit 2 in-service amount in revenue requirement is a final determination. The resulting revenue requirement is finally determined as part of setting just and reasonable payment amounts. To take the contrary view and classify approval of the DRP costs as interim would necessarily make the revenue requirement that includes the DRP costs and the resulting payment amounts interim as well. This is in direct contravention of section 6(2)12, which requires the OEB to establish a five-year revenue requirement, and should be rejected by the OEB.[35]

Fundamentally, just because a component of revenue requirement is subject to a variance account treatment where differences between forecast and actual amounts are reconciled, does not render the approval of that amount or the revenue requirement which it forms part of, interim. In every past payment amounts application, the OEB has approved revenue requirements and resulting payment amounts that contained elements that were subject to subsequent true-up in D&V accounts. Not once, has this fact caused the OEB to declare either the revenue requirement or the payment amounts interim or cause the re-examination of the original approval.

For GEC and CCC the interim nature of the OEB's approval of the in-service amount is tied to GEC and CCC's position that the appropriate level of review for Unit 2 is: any and all "contingency" spending would be subject to tracking in the CRVA and a future prudence review. CCC justifies its position on the basis that OPG is incapable or unwilling to identify imprudent

[35] AMPCO makes a similar proposal for interim treatment, which should be rejected for the same reasons set out in this paragraph (AMPCO argument, para. 278).

costs (CCC argument, p. 10). GEC suggests that OPG would hide mismanagement by using the contingency budget (GEC argument, p. 26).

CCC based its position on an exchange between Vice Chair Long and Mr. Reiner, about the identification of imprudent costs. Referring to a simple example of a lost iPad, the Vice Chair inquired as to examples of costs for which recovery would not be sought. The essence of Mr. Reiner's response is that, at this juncture of the Program, such costs are not envisioned:

> I can't foresee that sort of thing even if I took your example on the iPad. People can make mistakes, and what we would do on the project -- it's how we, as management, respond to that. Do we turn a blind eye, or do we take a corrective action to deal with the issue so it doesn't repeat itself?
>
> Everything we have built in our processes, it touches on corrective action, it touches on risk management, on oversight, on having external entities look in and advise us on things that they see that we might not be seeing. All of our processes are geared towards taking reasonable action to correct that event. (Tr. Vol. 4, p. 112 (emphasis added)).

OPG is not denying that imprudent costs could occur if the right actions are not taken. However, as Mr. Reiner indicates, it is OPG's intent to manage risk and take corrective actions. It is entirely possible for OPG to experience an event that would otherwise require a contingency draw, but through application of sound management, employ actions elsewhere to mitigate the need for or reduce the amount of contingency. Using the Vice Chair's iPad example, on losing the iPad, a person may check lost and found, acquire a used iPad as a replacement or share an iPad.

Since all risk events cannot be avoided, the key aspect is OPG's response to and management of the events that occur. As Mr. Roberts indicated, "[a]ll megaprojects experience some form of cost and/or schedule issues, which may include but not limited to commercial challenges, changes, unexpected and high-impact events and/or delays. It's not a question of whether these types of events will occur. It's a matter of how OPG handles and responds to these issues when they arise" (Tr. Vol. 7, p. 17). OPG should not be subject to a granular review of its contingency just because it has done an extensive review of the risks and attributed costs to them, which independent experts have confirmed meets the best industry standards for project controls and procedures.

The approach OPG is proposing for the DRP costs is identical to the interpretation and approach that the OEB has adopted in every previous consideration of the CRVA. When the OEB considers disposition of CRVA balances, it reviews any variance between amounts originally approved on a forecast basis and actual amounts expended, but it has never reconsidered the forecast amounts set out in its original approval.

SEC, CCC or GEC ignore the OEB's previous treatment of Section 6(2)4 Costs. They provide no explanation of how their proposed treatment of DRP costs can be reconciled with the OEB's previous approval and treatment of other Section 6(2)4 Costs. In OPG's respectful submission, the OEB should continue to apply the CRVA as it has previously done and reject positions that would make the initial approval for the costs of projects covered by section 6(2)4 subject to a full reconsideration at the time of the disposition of any balances in the CRVA.

The Componentization of Unit 2 Costs in the CRVA

OPG filed extensive evidence supporting the reasonableness of including the forecast Unit 2 in-service amounts and related project costs in OPG's revenue requirement. OPG has requested that the OEB approve its forecast amounts and expects that approved amounts will form part of the authorized, final revenue requirement. The amounts approved by the OEB in this Application will be the base against which any future actual costs and in-service amounts would be assessed to establish a variance and balance recorded in the CRVA. If the actual in-service amounts and costs ultimately exceed the approved amount, OPG would need to establish prudence to recover this variance in a subsequent proceeding disposing of CRVA balances.

Although there are a number of different projects and activities that are part of the refurbishment of Unit 2, it is entirely correct to record the variance between the approved in-service amount and actual in-service amount in the CRVA and consider any variance in the manner proposed by OPG because the refurbishment of Unit 2 is a single project, notwithstanding its complexity and size. Unit 2 refurbishment has one simple and singular objective to refurbish the unit in order to return it to service and generate electricity for an expected life of 30 years. No one project, component or bundle that forms part of the Unit 2 refurbishment can fulfill the singular objective of the refurbishment. The projects, components, and bundles must be completed in their entirety to achieve the purpose of refurbishing Unit 2. This is the reason that expenditures on each underlying project, component and bundle become used and useful at the time the unit is returned to service, and not before.

To consider it any differently is to artificially treat Unit 2 refurbishment as if it were multiple independent projects rather than a single, complex integrated program. Because a megaprogram is dynamic and interdependent, the owner must manage issues across the entire program and not in isolation. Under OEB staff's paradigm, an escalation of cost in one of its prescribed "components" would need to be considered from a prudence perspective irrespective of how the actual cost of refurbishing Unit 2 compares to forecast. However, in actually managing a complex interdependent program, higher cost may be incurred in one area to address a risk or resolve an issue in another area, which, when taken as a whole, is to the benefit of ratepayers (Tr. Vol. 2, pp. 99-100). These types of dynamic decisions are made frequently on megaprograms with the size and complexity of the DRP, and it would be practically impossible to keep track of every such decision on a cost-by-cost or component-by-component basis. OPG respectfully submits that a cost-by-cost or component-by-component review is not an appropriate way to determine an in-service amount in this proceeding, or to assess variances in future proceedings.

Therefore, for purposes of the CRVA, the relevant Unit 2 in-service amount is the full forecast of $4,800.2M. That is the base against which any variance should be considered. To consider future variances from in-service amounts on a "component-by-component" basis is an abstraction that is inconsistent with the declared need and regulatory treatment of the Unit 2 refurbishment.

Ignoring the singular purpose of the Unit 2 refurbishment, OEB staff and intervenors (primarily SEC, GEC, CCC and CME), propose a future CRVA variance analysis that is based on a componentization of the work undertaken to refurbish Unit 2 (OEB staff argument, p. 56; SEC argument, paras, 4.5.7-4.5.12; GEC argument, p. 26; CCC argument, pp. 10-12; CME argument, para. 182). OEB staff submit 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. OEB staff submit that the actual costs of each aspect of the DRP must be considered prudent on a standalone basis for it to be recovered from ratepayers. Therefore, OEB staff submit that a detailed review of all incremental spending related to each component of the DRP must occur.

OEB staff ask that, as part of its Draft Payment Amounts Order in this proceeding, OPG provide a sufficiently detailed list of all of the components of the Unit 2 refurbishment and a list of all of the campus plan projects (> $5M) 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 amount (based on the OEB's final determination in this proceeding) with the related applied for and approved contingency amounts shown separately (OEB staff argument, pp. 56-60).

OPG respectfully requests that the OEB approve in-service amount of $4,800.2M for Unit 2 and $377.2M for F&IP, SIO and Early In-Service projects in order to set payment amounts. OPG believes that this is the appropriate determination for the OEB to make, rather than determining the cost of individual DRP components. As noted, the objective of the DRP and the reason for its need being included in O. Reg. 53/05 is to refurbish the applicable unit, return it to service, and have it generate electricity, all at a reasonable cost. The expenditure on any one particular cost item or the completion of one component will not in itself result in a refurbished unit and its ultimate return to service. OPG respectfully submits that the OEB should consider and decide on the cost necessary for the execution of the Unit 2 refurbishment as a whole.

In effect, OEB staff's proposal would convert the disposition of the CRVA into a rehearing of the Unit 2 refurbishment in-service amount determined in this proceeding. Under the OEB staff proposal each component of the Unit 2 refurbishment will be dissected and reassessed and a rationale required for it. OPG submits that is not an appropriate or efficient way to proceed. Rather, the end result of the current proceeding should be the issuance of a final order that establishes the revenue requirement associated with the approved in-service amounts and costs of the Unit 2 refurbishment and related F&IP, SIO and Early-In Service projects during the IR term.

That OEB staff seek a rehearing of these determinations is reinforced by OEB staff's position that upon disposition of any CRVA balances, OPG should be required provide information, which shows not only the difference between the actual and the OEB-approved in-service amounts, but also compares the actual in-service amounts to the originally applied-for in-service amounts (OEB staff argument, p. 60). OPG submits that this is not an appropriate use of the CRVA.

Furthermore, OEB staff state that the CRVA exists to true-up actual contingency costs incurred, and that the OEB should approve only the contingency amounts that are necessary for OPG to meet the DRP's P37 working schedule. The effect of this would be to use the CRVA as a cost deferral mechanism, since, as noted below, contingency will be incurred as a cost of the refurbishment and at a confidence level higher than P37. OPG respectfully submits that this would be inconsistent with the purpose of the CRVA, which is to true-up variances between approved and actual costs. The RSDA is the appropriate mechanism for cost deferral.

With respect to the RSDA, OEB staff take the position that OPG's request for the P90 contingency amounts is "objectionable" given the regulatory requirement for the OEB to smooth weighted average payment amounts through the RSDA (OEB staff argument, p. 52). In this regard, OEB staff incorrectly combine the determination of revenue requirement and the deferral of that revenue requirement. These are separate exercises. Typically, the OEB first determines the revenue requirement based on a reasonable forecast and then determines the extent to which, if any, recovery of such revenue requirement should be deferred. OPG has provided a forecast of the Unit 2 refurbishment in-service amount inclusive of contingency at a P90 confidence level, which OPG believes to be reasonable based on the reasons set out herein. As a result, OPG respectfully submits that this is the approach the OEB should follow here, as discussed in Issue 9.2 (Section 10.2). OEB staff by, effectively excluding an appropriate amount of contingency from the in-service amount, is altering the use of the CRVA and establishing it as a mechanism to defer revenue requirement and thereby repurposing the CRVA and using it as a substitute for the RSDA.

In theory, SEC agrees with OPG's position that if actual total costs equal approved costs, no further prudence review is required with respect to the CRVA (SEC argument, para. 4.5.5). SEC then argues that while this applies in the usual circumstance, it should not apply here because the DRP "is not a normal capital project" (SEC argument, para. 4.5.6). Where OPG and SEC differ is over the question of whether the Unit 2 refurbishment is a discrete project or a series of independent activities. As demonstrated above, Unit 2 refurbishment is a single project undertaken for a single purpose and should be viewed on that basis.

SEC attempts to obfuscate the issue by focusing on the combined cost of all 4 Darlington units, instead of the Unit 2 costs, which are at issue in this proceeding. SEC incorrectly states that the baseline against which actual amounts will be measured in a future review is unclear – is it Unit 2 and the F&IP and SIO projects or all of the DRP (SEC argument, para. 4.5.4)? This is a red herring as OPG has clearly stated the approvals it is seeking in this Application (Ex. D2-2-1, p. 6; Ex. N2-1-1, p. 5).

SEC also attempts to justify the componentization of the Unit 2 refurbishment by pointing to the size of the DRP as a whole and a budget for Unit 2 relative to the other 3 units (SEC argument, para. 4.5.6). At no time has OPG sought approval in this proceeding of costs associated with the other 3 units. The refurbishment of Unit 2 is the focus of this proceeding and its approved in-service amount is the future baseline for determining any variance. SEC feigns confusion to obscure the fact that it has no real argument to justify treating Unit 2 refurbishment differently than other projects.

Furthermore, SEC mistakenly offers the Toronto Hydro ICM Decision (EB-2012-0064) as support for OEB approval of components or bundles. In the Toronto Hydro application, Toronto Hydro sought the approval of multiple projects composed of numerous jobs. The OEB held that future true-ups were to be considered on a project basis without the shifting of expenditures between projects, although funds could move freely among the jobs comprising a specific project.[36] In the Toronto Hydro ICM Decision, the OEB used the approved projects, and not the individual jobs, as the baseline against which future variances were to be calculated.

In the Toronto Hydro application, each of Toronto Hydro's projects addressed a specific type of equipment or ongoing obsolescence issue (e.g., wood pole replacement or station transformer upgrades) and as such each represented an end in and of itself notwithstanding the fact that many projects had multiple jobs. Here too, the Unit 2 refurbishment is a singular project. It is composed of a number of interrelated activities all undertaken to accomplish the discrete result of refurbishing Unit 2, returning it to service and generating electricity for 30 years. In effect, the Unit 2 refurbishment is the only discrete project in question and, as acknowledged by SEC, the typical application of the CRVA should apply.

[36] EB-2012-0064, Toronto Hydro-Electric System Limited Partial Decision and Order (April 2, 2013), p. 75.

A more direct example of how the OEB has treated a single, large complex project is the OEB's review of the NTP. Although the project comprised of a number of discrete activities from tunnel boring to the fabrication and installation of stainless steel gates at the tunnel's entrance, the OEB did not separately examine the cost of each activity relative to its initial budget. Rather it looked at the overall amount by which the project cost exceeded the initial budget approved by OPG's Board of Directors and conducted a prudence review on that basis (EB-2013-0321, Decision with Reasons, pp. 30-34).

Unit 2 Contingency

There are three different proposed contingency levels put forward by OEB staff and certain intervenors. OEB staff propose that the OEB accept the contingency amount associated with the P37 working schedule (OEB staff argument, p. 38).[37] SEC and AMPCO propose a P50 level contingency amount (SEC argument, para. 4.4.17; AMPCO, para. 31). CCC proposes that there be no allowance for contingency (CCC argument, p. 16). EP, LPMA, PWU and SEP support OPG's use of a P90 level of contingency (EP argument, p. 7; LPMA argument, p. 12; PWU argument, para. 9; SEP argument, p. 1).

OEB staff submit that the OEB should approve only the in-service amounts for Unit 2 contingency based on OPG's working schedule (which reflects a P37 confidence level). The basis for this position is that the need for contingency amounts should be considered differently from a planning/project management perspective and a ratemaking perspective (OEB staff argument, pp. 49-55). Although advocating a P50 confidence level for contingency, AMPCO holds the same position.

Both OEB staff and AMPCO accept that it was appropriate for OPG to develop a schedule and cost estimate at a P90 confidence level, but only for the purpose of providing 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 under different risk scenarios (OEB staff argument, p. 52; AMPCO argument, paras. 10-12, 47). However, both OEB staff and AMPCO believe that, on a regulatory basis, it is not appropriate to approve the full amount of the P90

[37] This position is supported by CME, QMA and VECC (CME argument, paras. 171-176; QMA argument, p. 12; VECC argument, para. 2.2.3).

contingency as there is a possibility of OPG over-recovering its Unit 2 costs through payment amounts in the IR term.

The P90 schedule and cost estimate was derived from extensive planning leading up to Release Quality Estimate ("RQE"), all of which was commended by both Pegasus-Global Holdings, Inc. ("Pegasus-Global") and by Schiff Hardin (AIC, pp. 55-57). The planning was undertaken not just to provide a conservative estimate to OPG's shareholder, but to ensure the success of the DRP by recognizing up-front that a project of the size and magnitude of DRP has material risks that will materialize. As such these risks need to be recognized and mitigation measures for them planned.

The related costs in the form of contingency appropriately form the basis of OPG's forecast in-service amount. This is the nature of project execution – risks are inherent and contingency required. While OEB staff and intervenors have chosen to ignore this, OPG respectfully submits that the OEB should not ignore these realities when considering forecast in-service additions from a regulatory perspective. In fact, contrary to OEB staff assertions, OPG sees no distinction between costs arising "from a planning/project management perspective and a ratemaking perspective" (OEB staff argument, p. 52).

In this regard, AMPCO puts forward an unfair and incorrect definition of what a P90 confidence level means with respect to contingency. According to AMPCO, a 90% confidence level for contingency means "rate base additions … are 90% likely to be higher than actual incurred costs" or "90% likely to over recover in rates" (AMPCO argument, para. 3). OEB staff's submission suffers from the same fallacy when it argues that, "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" (OEB staff argument, p. 52). This is not correct. The correct definition is that P90 gives the project proponent "a 90 percent probability that you will fall within the estimated cost and schedule" (Tr. Vol. 5, p. 153). Put another way, there is a 90% chance that the amount will not be exceeded (Ex. M1-4.3 AMPCO-9). In effect, a P90 confidence level means that OPG will very likely meet its budget and as such, this is an appropriate estimate for the OEB to establish an in-service amount for Unit 2. It is only appropriate that a project proponent place before the regulator its best estimate and work to stay within its budget. As stated by LPMA, using P90 confidence level is appropriately conservative and provides ratepayers with a measure of protection against future cost pressures (LPMA argument, p. 12).

SEC shares AMPCO's and OEB staff's view for similar reasons. Referencing Dr. Galloway, SEC states that the selection of a confidence level for contingency is "reflective of the risk appetite of the owner" (SEC argument, para. 4.4.16). However, SEC has not fully and accurately reflected Dr. Galloway's comments. Dr. Galloway's full reference is:

> Selection of a confidence level is primarily reflective of the risk appetite of the owner. If the owner wishes to reduce the risk of overrunning the estimate, using a higher confidence level reduces the likelihood of a budget overrun and provides provisions for risks unknown at the time of the estimate, but likely to appear as the project progresses. On a megaprogram, given the extended duration for execution and increased complexities compared to a typical project, it is common for a high confidence level to be selected as it provides more assurance that the estimate will be adequate for the duration of the program. (Ex. D2-2-11, Attachment 3, p. 20 (emphasis added)).

To provide the OEB, and thereby ratepayers, with assurance that the estimate will be accurate for the duration of the program is a fundamental aspect of this proceeding. Given the size, complexity, nature of the risks, potential cost consequences, and compounded by the nature of a megaprogram that will be in an execution phase for close to 10 years, it was prudent for management to recommend a P90 contingency amount for the DRP (Ex. L-4.3-12 OAPPA-9).

Effective project planning leads to good ratemaking since the OEB has before it the best estimate of project costs reflecting the delivery of the project on time and on budget. OEB staff and AMPCO, in effect, propose that the OEB accept for rate making purposes a forecast which is not representative of industry best practice and has very little likelihood of being the cost of the Program. A P37 schedule and cost estimate reflects a 63% likelihood that OPG will exceed the budget and schedule. A P50 schedule and cost is a 50% likelihood OPG will exceed the budget and schedule, while schedule and cost without any contingency have a 100% likelihood of being exceeded. To establish just and reasonable rates, the OEB must provide for the recovery of reasonably incurred costs. It would be unfair for the OEB to penalize OPG by basing the in-service amount for the DRP on a level of contingency that does not reflect the best estimate of the true cost of the project.

OPG should recover its forecast level of contingency as part of the forecast in-service addition of Unit 2. As OPG explained throughout this proceeding, 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. Contingency is included as a component of a project estimate just like any other cost component of a project. It is not an extra amount or surplus that will be spent if the project does not go as planned, nor is it a tool to compensate for an underdeveloped project plan. It is a necessary, legitimate and thoughtfully developed part of the estimated project cost based on residual (post-mitigated) risk and uncertainty. The consideration of contingency in this way is fully recognized as industry practice (Ex. D2-2-7, pp. 1-2).

As set out in OPG's AIC, OPG's contingency was developed using both qualitative and quantitative methods, including an integrated, probabilistic, Monte Carlo simulation of the Program's cost and schedule. Furthermore, independent experts have supported OPG's use of a P90 estimate (AIC, pp. 53-57). OEB staff and the intervenors ignore the opinion of both Pegasus-Global and Schiff Hardin that P90 is acceptable and represent best practices (AIC, pp. 55-57).

AMPCO attempts to diminish the relevance of Dr. Galloway's and Mr. Robert's expertise related to the regulatory approvals currently before the OEB. According to AMPCO, because Dr. Galloway is an expert on prudent actions to execute, plan and mitigate project risk, her expertise is only appropriate in the project management sphere and not the regulatory sphere (AMPCO argument, paras. 33-41). However, this is a mischaracterization of her experience and misapprehends the point of the regulatory process.

An applicant seeking approval of in-service additions must show to the OEB that its cost have a proper basis – that it has planned, scheduled, costed and accounted for risk in a manner which enables the OEB to have confidence that the in-service amount is the best, most accurate forecast of cost. Evidence from experts like Dr. Galloway provide an independent view that OPG took the necessary steps, completed its due diligence and addressed the inherent risks in a prudent manner to derive the cost estimate provided. Therefore, AMPCO's efforts to question the relevance of Dr. Galloway's testimony should be disregarded. As noted, the dichotomy espoused by OEB staff and the same intervenors between project development for commercial purposes and project development for regulatory purposes is a false one and should not be accepted by the OEB.

SEC and AMPCO argue that a P50 confidence level for contingency provides for more transparency than P90 (SEC argument, para. 4.4.13; AMPCO argument, para. 5(d)). Given that OPG has provided complete and detailed evidence on the development of the P90 contingency and a breakdown of its associated cost, OPG fails to see how use of the P50 contingency figure improves transparency. OPG has been transparent in this proceeding on every aspect of its planning, costing, schedule, risk and execution. It has produced extensive prefiled evidence including third party and expert reports and, when asked, it produced all documentation both internal and third party prepared.

OPG understands its obligation to show any amount recorded in the CRVA to reflect costs in excess of the in-service amount for Unit 2 and the F&IP and SIO projects. In this regard, a similar level of transparency will be expected. However, the OEB should not, as proposed by OEB staff and the above intervenors, structure its approval in such a way that will require a rehearing of the DRP evidence given that it has sufficient evidence before it to support the use of the high confidence estimate as the approved in-service amount for the Unit 2 refurbishment.

SEC also argues the P50 confidence level used for OPG's contractor target price should also be used for ratepayers in establishing OPG's in-service amount for the DRP (SEC argument, para. 4.4.10). There are some parallels between this argument and the one that OEB staff has employed for using the P37 level of contingency. OPG has good reasons, which are to the benefit of the ratepayers, to adopt the P37 cost and schedule as its <u>*working*</u> cost and schedule basis. OPG recognizes that it has a responsibility to ratepayers to execute capital projects as effectively and efficiently as possible. OPG's choice of a P37 working schedule is a tool to drive and motivate efficiencies while increasing the level of transparency when contingency is used. As OPG indicated in Ex. D2-2-6, page 6, the planned outage duration is what OPG will use to manage day-to-day performance, and it "will also be used to determine contractor incentives and disincentives, where applicable."

Furthermore, the P50 cost and schedule allows OPG to set aggressive targets for its contractors, but when risks materialize, contractual mechanisms are in place to motivate contractors to deliver the project as cost effectively and in as short a time period as possible, while maintaining safety and quality standards. As Mr. Rose explained in the hearing:

> If we let the contractor go to P90, the target price would be higher, and if they delivered for P50, we wouldn't have recourse to adjust that through the CRVA. ... If we gave the contractor P90, that's profit for them. So that's why we have a lower probability for the contractors than we do for the amounts that we are carrying. (Tr. Vol. 5. p. 37).

Similarly, the use of the P50 level of contingency in target price contracts drives contractors to the lowest cost and the shortest schedules, which is to the benefit of ratepayers. OPG should not be disadvantaged because it chose a negotiating position with its contractors that benefits ratepayers. OPG submits that, the OEB, in considering in-service amounts, must look at the program in its entirety to reflect the best forecast of all costs, and should not inappropriately adopt a tool used to motivate contractor performance to establish forecast in-service amounts.

SEC also questioned the balance that OPG is striking relative to ratepayers by using a P90 confidence level instead of P50 (SEC argument, para. 4.4.10). OPG submits that based on the extensive evidence put forth in this proceeding, using P90 as a reasonable forecast of in-service additions for Unit 2 represents a fair balance of risk between OPG and its customers. As Concentric opined, it is the normal course that a company undertaking such a large project would seek approval of its costs from its regulatory commission in advance of incurring them:

> In terms of the P90 estimate and reliance on an estimate in order to proceed with a project like this, we're not aware of any company that would undertake this magnitude of investment without a very strong signal from its commission that there is both a need for the project and an assurance that the company's planning process and cost estimates are reasonable before it would proceed.
>
> So I think that same type of understanding is implied or explicit within what the OPG has asked the Board to provide in this proceeding. It's asked them for approval for a specific amount. It's a gated project, so as the project approves, it will be coming back to the Board to ask for subsequent approvals. I think that's both a prudent approach from a planning standpoint, and I think, quite frankly, it would be imprudent on the company's part if it were to proceed completely at risk without some sort of assurance that it was doing so with the blessing of the Board in that regard, and with the Board finding it was in the best public interest to do so. (Tr. Vol. 19, p. 10 (emphasis added)).

Furthermore, Concentric opined that a request for approval of P90 estimate is both reasonable and prudent:

> I think it's prudent, from a company standpoint, to tighten that band as much as possible. It will have to show amounts above that estimate as being prudent before it would be able to file for inclusion in rates in the future.
>
> And as we know, and I think the record is established in this proceeding, there are a lot of ways that costs can vary from estimates even for the best planned projects of this type. So I don't find it unusual that the company would be looking for that type of a band in that regard, because even with that band, I think the risks are still substantial. …
>
> the project is ultimately for the benefit of ratepayers. This is going to be producing long-term power for Ontario consumers for 30 years post refurbishment. So the benefits and the costs should move in parallel with each other. (Tr. Vol. 19, pp. 11-12).

Importantly, Schiff Hardin similarly acknowledged the importance of balancing the interests between the company and the ratepayers. As Mr. Roberts indicated, “Good policy seeks an equitable balance [between] the interests of the utility and the ratepayers” (Ex. M1-4.3 EP-6).

OPG further submits that by advocating for either a P37 or P50 cost for the Unit 2 refurbishment, the parties in this proceeding are being selective and ignoring the fact that cost and schedule operate in tandem. A P37 cost, for example, also reflects a P37 schedule which contemplates an in-service date at least five months earlier than the P90 schedule, which is the basis of OPG's Unit 2 refurbishment proposal. Similarly, a P50 cost would reflect a P50 schedule, which would be three months earlier than the P90 schedule. To be consistent, any proposal for a P37 or P50 cost should also include the corresponding earlier in-service date.[38] To do otherwise would penalize OPG for an amount greater than just a reduction in in-service amounts from that reflected in P90 costs to costs related to P37 or P50, since such a determination without a corresponding adjustment to in-service date would result in a loss of return on capital and imply a schedule delay that is unjustified.

Definition Phase Costs – In-Service Date for Common Costs, Early In-Service projects, F&IP and SIO

SEC submits that the DRP’s Definition Phase costs should be allocated across the four units, with 50% in service with Unit 2 (SEC argument, para. 4.4.24). GEC submits that, because there

[38] An earlier in-service date would also have an impact on production. Undertaking JT2.14 provides the net impact to the generation forecast in the test period using a P50 schedule for the DRP. OPG expects that a P37 schedule would result in substantially lower production during the test period.

is a possibility that future unit refurbishments may be cancelled, OPG's Definition Phase spending cannot be determined to be prudent at this stage as the costs would be too high for a one-unit project (GEC argument, p. 18). OEB staff[39] and PWU submit that, in accordance with the used and useful regulatory principles, it is appropriate that the Early In-Service Projects, F&IP, SIOs and other common projects be placed in service at the time of their completion (OEB staff, p. 45, PWU, paras. 28-30). OEB staff also submit that it is appropriate to place projects common to the refurbishment of multiple units at the same time as Unit 2 because, while they may be necessary and/or beneficial to the refurbishment of future units, "they are used and useful at the time that Unit 2 enters service" (OEB staff argument, p. 45).

Unit 2 in-service amounts include Definition Phase costs of $2.2B. All of the Definition Phase costs to be placed into service with Unit 2 relate to preparation and planning work which was required to allow OPG to be ready to refurbish Unit 2. Figure 1 of Ex. D2-2-4 shows that the $2.2B Definition Phase expenditures were spent on the following:

- Retube and Feeder Replacement ("RFR") Mock-up and Tooling
- Turbine Generator Parts
- Vendor/EPC Definition Phase Planning
- Facilities & Infrastructure and Refurbishment Support Facilities Projects
- Safety Improvement Opportunity Projects
- OPG Definition Phase Planning and Support Services
- Interest

Approximately $1B of the $2.2B is associated with the Early In-Service projects, F&IP, and SIO (Ex. L-4.3-1 Staff-54). The Early In-Service projects are assets arising from work performed for the unit refurbishments that will be placed in service and included in rate base before the refurbishment of the first unit is complete because they provide immediate benefit to the station.[40] As committed within the Environmental Assessment and Integrated Implementation Plan, the SIO are to be placed into service upon completion and are useful to OPG's current

[39] QMA and VECC also adopted OEB staff's submissions.
[40] The Early In-Service projects are split between RFR Mock-up and Tooling, Vendor/EPC Definition Phase Planning, and OPG Definition Phase Planning and Support Services.

and future nuclear operations independent of whether the DRP is completed. The F&IP are pre-requisites for unit refurbishments and will be placed in service and included in rate base when they are used and useful to OPG.

To the extent that there have been unit-specific engineering costs incurred during the Definition Phase that are not related to Unit 2 (i.e., relating only to other units), such costs are not included in the amounts coming into service with Unit 2 in 2020 (Ex. D2-2-10, p. 2).

SEC asserts that the $1B of Definition Phase costs not related to F&IP, SIO or Early In-Service activities cannot credibly be included in the in-service amount for Unit 2 (SEC argument, paras. 4.4.21 to 4.4.23). Notwithstanding that these costs were incurred to permit Unit 2 refurbishment to proceed, SEC bases its entire submission on the hypothetical circumstance that OPG would only refurbish a single unit and an excerpt of a transcript response that is taken out of context (SEC argument, para. 4.4.23). Not only does SEC ignore the evidence set out above, it also ignores the response to its counsel's cross examination questions on this very issue. In particular, in response to the hypothetical put forward by SEC, Mr. Rose specifically stated:

> Of course, as Mr. Reiner says, it's a hypothetical situation. It's not how we planned this job. But being very close to the planning that happened in here, I don't anticipate we would do any less planning for a single unit. The planning that we did, which was about developing the scope, developing the cost estimate, performing engineering and developing a schedule, was all required to execute unit 2. (Tr. Vol. 3, p. 24 (emphasis added)).

GEC takes a different tact and attempts to tie the overall in-service amount for Unit 2 to the completion of all four DRP units by asserting that the total cost cannot be prudent or reasonable unless the common costs for Unit 2 also serves the other 3 units (GEC argument, p. 18). In OPG's submission, this misses the point. OPG is not arguing that the common costs for Unit 2 will not benefit the other units. Rather, OPG's position is that the $2.2B Definition Phase costs were required in order for the Unit 2 refurbishment to proceed and were incurred for this purpose. On this basis, it is appropriate that these costs are in-service when the resulting assets are used or useful. For the planning costs, this will occur when Unit 2 returns to service.

OPG notes that OEB staff, QMA, VECC and PWU support OPG's position. No party has taken the position that the Definition Phase activities were imprudent and as such, these costs are properly recoverable as part of the Unit 2 in-service amount.

Costs are already in excess

SEC remarks that, taking into account management reserve and the reclassification of certain projects to the Nuclear Operations portfolio, OPG has already exceeded its $12.8B budget for the DRP (SEC argument, para. 4.1.6). GEC makes similar submissions, as well as noting that OPG's increased cost of capital and interest in the RSDA obscure the true cost of the DRP (GEC argument, p. 22).

OPG submits that there are fundamental errors in these submissions. As OPG has stated in previous proceedings, the concept that RQE represents the definitive baseline cost and schedule was built into refurbishment from the start (Tr. Vol. 1, p. 69; also see, for example, EB-2013-0321, Tr. Tech. Conf., July 9, 2014, p. 37 and Tr. Vol. 15, pp. 147-148). OPG has stated throughout this proceeding and in its AIC that significant effort went into developing the RQE value of $12.8B, and it was approved by the OPG Board of Directors on November 13, 2015.

Scope definition was a large part of the rigorous RQE development process. OPG reviewed the cost classification of DRP projects as part of that process to ensure clarity between costs included in refurbishment versus costs needed for the operation of Darlington in general. As a result of this process, some DRP projects were reclassified to the Nuclear Operations portfolio (Ex. D2-2-10, p. 9). These costs did not form part of the RQE and as a result, they do not represent a variance to the RQE value of $12.8B.

Similarly, the $800M of management reserve that SEC points to does not form a part of RQE or the DRP budget, and never has (Tr. Vol. 1, p. 27; Tr. Vol. 3, p. 50). Management reserve represents high consequence, low probability events that are outside the direct control of OPG. As Mr. Lyash characterized, management reserve events include:

> …some economic disruption that creates runaway interest rates, some significant natural disaster that breaks down infrastructure, and we don't consider those as likely to occur. But we wanted to ensure that the board was aware of them and that the shareholder was aware of them in making the decision to proceed. (Tr. Vol. 1, p. 76).

Thus, unlike with contingency events and contrary to SEC's submissions, OPG does not consider management reserve to be amounts that it expects to spend. Rather, these are costs that are unlikely to materialize. Nevertheless, to provide a complete picture, OPG wanted to convey both the nature of these costs and their potential magnitude, arrived at through a sensitivity analysis, to its Board of Directors. Pegasus-Global similarly opined that management reserves are not included in budgets since they are not expected or intended to be expended (Ex. D2-2-11, Attachment 3, p. 27).

GEC submits that OPG's increased cost of capital, the interest earned through the RSDA, and the reclassification of projects to Nuclear Operations obscure the true cost of the DRP (GEC argument, p. 22). GEC's submissions are incorrect. As stated above, the reclassified projects were never part of the RQE estimate. With respect to the interest earned through the RSDA, OPG submits that GEC's argument has the same error as that of OEB staff (described earlier), where the determination of revenue requirement is incorrectly combined with the deferral of that revenue requirement. These are separate exercises. With respect to OPG's increased cost of capital, OPG submits that its capital structure is set on a company-wide basis and the proposed increased in equity thickness is not specifically attributable to any one generation site (Ex. L-3.1-8 GEC-1). The OEB has already accepted this position in its February 15, 2017 Decision and Order on Motions Filed by Green Energy Coalition (p. 4).

GEC further submits that OPG has not demonstrated that its RQE value is reasonable, noting that OPG did not have independent assessments of the actual costs of the DRP done (GEC argument, p. 18). OPG submits that this expectation is unreasonable. OPG has spent in excess of five years planning and developing the RQE. As Mr. Reiner indicated:

> if you look at just the time it took to plan this project, to get from when we -- from the start of definition phase, so January 2010 to being ready to begin execution on the first unit, the complexity and effort associated with building up the estimates, we deemed it virtually impossible for an independent body to derive an estimate completely separate. …
>
> But the process we took internally to ensure we have the right checks and balances in place, estimating was done by people independent from projects, for example. We brought in expertise to help us with estimating that have the ability to look at a scope of work and quantify an estimate. And because of the complexity, it took us over a year to get the Class 2 estimate compiled for just the RFR project, and the effort that went into the option we took is bring in experts to have a look at the approach we took, the method we used, do some sampling to see if that methodology was followed. Would it result in a reasonable outcome in terms of the project estimate? That's what we opted to do. (Tr. Vol. 2, pp. 173-174).

OPG submits that it would have been unreasonable to engage an independent party, who would have taken the same amount of time, if not more, to independently determine the anticipated cost of the DRP. However, as stated above, OPG took steps to check and ensure that the processes OPG used to determine the estimate were reasonable and prudent, and many of the major RQE components were assessed by independent experts. As OPG highlighted in its AIC, independent experts and oversight bodies, including KPMG, Palisade Corporation, Burns & McDonnell Canada Ltd. and Modus Strategic ("BMcD/Modus"), and CALM Consulting reviewed OPG's estimating methodology and approach and have all confirmed that, based on the approach taken by OPG, the $12.8B estimate is reasonable (AIC, pp. 51-57). Furthermore, KPMG performed a deep dive assessment of the RFR, Balance of Plant, and Operations and Maintenance estimates in its report on "RQE Governance & Process Review and RQE Cross Cutting Vertical Slice Review" (Ex. D2-2-8, Attachment 1).

OPG submits that it is the RQE that serves as the baseline against which the success of the DRP will be measured (AIC, p. 33). The costs that SEC and GEC have pointed to as evidence that OPG has already exceeded this baseline are not, and never were, part of the RQE.

Staffing Reductions

OEB staff submit 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 IR term. CME adopted OEB staff's argument (CME argument, para. 193), while SEC noted the issue, but did not specifically agree with OEB staff on the proposed disallowance (SEC argument, paras. 4.10.1-4.10.8). SEP disagreed with OEB staff's submissions, noting that OEB staff's proposal puts at risk successful execution of the DRP (SEP argument, p. 6).

OEB staff's submission asserts that actual DRP labour spending has consistently been below forecast. In this regard, OEB staff point to OPG's 2013-2015 Business Plan and the variance between, (1) the 2013-2015 planned headcount for the DRP and (2) the actual headcount for the same period. This reference is dated as the forecast in this Application is based on the RQE, which is different than the estimate provided in the 2013-2015 Business Plan. Therefore, the data in question does not provide a reliable trend. OEB staff also cite the 2016 data set out in Ex. J4.4. Based on a single year of data, 2016, showing the project management and oversight labour and managed task services (contracted) costs, OEB staff reaches the conclusion that staffing will remain below forecast throughout the Unit 2 refurbishment. OPG submits that OEB staff's recommended disallowance should be rejected because it is based on deficient data and, as set out below, does not take into consideration key evidence.

With respect, the 2016 data OEB staff referenced from Ex. J4.4 is not a reliable prediction of staffing during the Execution Phase given that at the end of 2016, the DRP was only 2.5 months into a 40 month execution schedule. Furthermore, those 2.5 months were during a period where the reactor was being defueled by OPG staff (Tr. Vol. 1, pp. 9-13). Since that time, contractors have been performing work on the critical path and the numbers of contractors has risen substantially. As a result, OPG has staffed up to perform the necessary oversight of the contractor work.

OPG has recognized the importance of staffing and has already put in place process improvements and a dedicated team to advance all hiring. The DRP now has a centralized Resource Management Team addressing all resource planning initiatives for the project, including advancing hiring and working with the recruitment organization to resource staff as efficiently as possible (Ex. L-4.3-2 AMPCO-87). In addition, OPG's recruitment organization has made several hiring process improvements, all aimed at helping the project resource qualified candidates as quickly as possible (*Id.*). A hiring campaign is underway to ensure that the resources are available when needed and to eliminate any resource shortfalls. In addition, hiring is underway for the Project Office, Construction, Engineering, and Project Planning & Controls and in the Project Management job categories (*Id.*). Mr. Rose also provided an update of the staffing initiative during the hearing:

> But we have significantly closed the gap between August and the end of the year, and we are slightly -- a little bit under where we want to be right now, and what we end up doing is we end up bringing in contractors to help facilitate that staffing gap.
>
> But what we did is we actually -- the organization has invested or spent considerable time putting in place recruitment programs, and we, in turn, put in a, within my organization, a process to help managers with the recruiting process. I mean, hiring somebody, going through interviews, and that takes time. We wanted our managers focused on the work, so we facilitated and helped them through the hiring, and <u>we hired about 200 people between August and the end of the year on the project.</u> (Tr. Vol. 3, pp. 30-31 (emphasis added)).

While OPG has taken longer to staff up to plan than initially anticipated, process improvements have been made to facilitate the hiring required and to ensure that OPG obtains appropriately qualified staff to perform the required work (Tr. Vol. 1, pp. 104-105). An initial execution staffing under-expenditure in a program the size, duration and complexity of the DRP cannot reasonably be interpreted as "historically overstated", as OEB staff have suggested (OEB staff argument, p. 48).

OEB staff also ignore the phased approach of the DRP. OEB staff's reliance on historical data for the 2013-2015 period is inappropriate since that period reflects the DRP's Definition Phase and not the Execution Phase where project management and oversight functions will be critical. OPG has only just begun the Execution Phase and, therefore, the historical numbers for DRP as a whole reflected in OPG's 2013-2015 Business Plan and in Ex. J4.4 are not the correct basis to use to assess the going forward staffing levels.

Furthermore, OEB staff seem to overlook the critical nature of the functions for which they propose to reduce funding. The project management and oversight labour costs that are the subject of Ex. J4.4 are integral to the Program and will be increasingly so as the DRP moves further into execution. Based on lessons learned, it is fundamental for the success of the DRP to have sufficient project management and oversight as part of the owner's team. This is a priority for the Program. To cut OPG's plan to hire project management oversight staff based only on (1) actual costs from the initial months of execution during a period where the critical path work was being performed by OPG staff, when (2) OPG is still ramping up its hiring program, would be inappropriate and would likely result in performance issues that would adversely impact safety, quality, schedule, and cost. SEP made a similar observation:

> OEB staff are recommending reductions in planned staffing levels which will put at risk the successful execution of DRP. This appears entirely counter intuitive, arbitrary, and unwarranted; and as such, this staff recommendation should be disregarded by the OEB in its Decision (SEP argument, p. 6).

OEB staff have also disregarded specific facts in Ex. J4.4 that placed the under-expenditure relative to plan for 2016 in context. As OPG explained, the under-expenditure was not due to over-budgeting for staffing generally, but timing variances across several categories, the largest of which include radiation protection services, procurement oversight and return to service programs.

OEB staff appear to recognize the inherent weakness in their argument and propose, as an alternative, a lower level of disallowance that is one half of their original proposal, but provide no basis for this alternative disallowance (OEB staff argument, p. 48). They state that a smaller disallowance is potentially justified by the difference between the definition and execution phases of the DRP, but this statement alone is an insufficient basis for any reduction to necessary project management and oversight staff. Further, OEB staff argue that should OPG incur labour costs in excess of any lower amount approved by the OEB, OPG will have the opportunity to explain why it was appropriate for the costs to have been incurred at a future CRVA proceeding (*Id*.).

OEB staff's proposal is unfair, since on the one hand they offer no conclusion on the reasonableness of OPG's plan, while on the other hand they propose that in-service amounts for Unit 2 should be reduced pending a potential determination relating to the CRVA. In effect, OEB staff are saying that, because they cannot determine the appropriate disallowance amount, OPG must at a later CRVA review show why its plan was correct in the first place as presented in this proceeding. It is not appropriate to selectively focus on areas of disallowance without a substantive basis for that disallowance and expect OPG to prove at a later proceeding the legitimacy of its original request. For the reasons provided previously, this alternative disallowance is equally unjustified.

OEB staff have also submitted 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 IR term, which should be provided to the OEB at the time that the CRVA is brought forward for disposition. For the reasons set out above, OPG disagrees with the component-by-component tracking of the DRP for purposes of future CRVA consideration. As indicated, the OEB should not micro-manage specific functions of the Program, such as project management and oversight, but rather should evaluate the DRP as a whole.

In recognition of a staffing shortfall as of January 2017 as per Ex. J3.3, Attachment 1, SEP also submits that OPG should be directed by the OEB in its Decision to make up this staffing gap with the necessary regular staff hires ASAP (SEP argument, p. 5). OPG submits that a direction to hire regular staff is not within the jurisdiction of this proceeding to review payment amounts. However, OPG notes that a project of this nature is different than staffing for the ongoing operations of a plant. In the case of operating a plant, the organization clearly knows what staff levels and skills are required to meet its objectives. Within a project environment, and especially so within a megaprogram, while planning is extensive to establish a resource profile for the project, agility in staffing to deal with issues, and/or respond to emerging risks, is required. As such, OPG will at times hire more staff in one area while delaying hiring of staff in another area. SEP's proposed direction is unnecessary as OPG continually reviews its staffing plan to ensure that the requisite staff, whether regular or contracted (as appropriate based on the needs of the Program and the company), are available.

There is no prescription for delivering a program with the size and scope of the Unit 2 refurbishment. OPG applied lessons learned and developed a plan, including its plan for owners' resources, to mitigate risks and maximize the likelihood of a successful program outcome. A program or project is not like ordinary course operations where staffing levels can be expected to remain stable over long periods of times. OPG needs to have appropriate levels of flexibility to adjust staffing levels across functions and recruit additional staff as the program changes over time. OPG submits that it has acted prudently in its staffing planning, initiatives and efforts for the DRP.

Contractor Performance

SEC submits that it is concerned with the work of OPG's contractors undertaking the DRP, [redacted] (SEC argument, paras. 4.10.10 to 4.10.19). [redacted]

OPG acknowledges that [redacted] have faced challenges. [redacted]

[redacted] After initial challenges, adjustments were made and lessons learned were implemented. OPG expects the contractors to improve over time through oversight and prompt corrective actions being taken. Effective oversight, such as that provided by BMcD/Modus, highlights both potential and actual issues, which allows management to address them early and effectively (AIC, p. 62).

OPG has worked with the contractors in this regard. [redacted] While there will be start-up issues and lessons learned in the beginning of any project, given the detailed planning for refurbishment, OPG submits that it has the oversight and project management teams in place to ensure that: (1) issues are identified early, (2) issues are addressed and resolved quickly, and (3) lessons learned are identified and applied to the DRP as it continues into execution.

Contracting Strategy, Contractual Negotiations, and Consistency with 2013 LTEP

In this section, OPG addresses the parties' specific submissions on the DRP contracts and contracting strategies.

Minimizing Commercial Risks through Contracts and the Allocation of Cost Overrun Risks

SEC submits that the OEB should be concerned about OPG's DRP contracts, noting that OPG, and as a result, ratepayers, bear the risk of cost overruns as opposed to the DRP contractors (SEC argument, paras. 4.11.5 to 4.11.12). GEC also submits that OPG has failed to externalize risks for cost overruns through its contracts in contravention of the 2013 LTEP principle of minimizing commercial risks (GEC argument, pp. 20-22).

Both SEC's and GEC's claims are rooted in the cost overrun scenarios presented at Ex. L-4.3-7 ED-4, Attachment 1 and Ex. JT1.20, Attachment 1. OPG submits that, as the responses to the interrogatory and undertaking clearly articulate and explained during the hearing, the cost overrun scenarios are not realistic scenarios, especially in the extreme scenarios that the inquiries posited (Tr. Vol. 3, pp. 71-72). Many simplifying assumptions were applied, schedule disallowances were not accounted for, and no contingency was drawn.

These issues can be illustrated using the RFR work bundle, the largest contract, as an example. Contrary to the parties' claims, the contractor is at risk since in aggregate it can lose up to 80% of its Fixed Fee through cost and schedule disincentives. The Fixed Fee encompasses the profit, overhead, and a risk amount that the contractor expects to earn on the job (Ex. D2-2-3, pp. 7-8). While OPG will continue to pay for actual costs, the contractor is losing the opportunity to recover overhead costs and to earn a profit, which is the very reason the contractor undertakes the work. Furthermore, since the Fixed Fee amount is not adjusted, the contractor does not earn more profit and overhead as the project's cost increases or the schedule runs longer – its profit and overheads are already set. This is a very powerful incentive for contractors to address any deterioration in cost and schedule performance. Otherwise, the contractor will, in effect, be working for free.

As this example illustrates, but the cost overrun percentages shown in Ex. L-4.3-7 ED-4 and Ex. JT1.20 fail to reflect, in a very real way, the contractor is in fact sharing any cost overrun. It is also worth emphasizing that the manner in which the contractor maximizes its profit and value to its shareholders is to complete its scope of work within the schedule and for an amount less than the target cost in order to be entitled to an incentive payment (AIC, p. 44).

OPG has also negotiated a number of contractual mechanisms that it would exercise to take corrective actions very early in the process in order to prevent cost overruns from continuing and reaching higher levels. These include:

- the ability to audit the contractor's costs;
- limitations on change orders from the contractors;
- cost and schedule disincentives to mitigate and recover from delays and cost overruns;
- provisions to address faulty work, warranty work and limited rework allowance; and
- the ability to suspend, transfer work to another contractor, or to terminate a contract for default if required.

GEC argues that OPG ought to have entered into a fixed price contracts in order to fulfill the 2013 LTEP principle to “minimize commercial risk on the part of ratepayer and government” (GEC argument, pp. 21-22). With respect to OPG’s observation that fixed price contracts would have been costly, GEC responds that, “Of course, that’s to be expected when one buys insurance, as OPG was directed to do but elected to avoid” (GEC argument, p. 22).

OPG fundamentally does not agree that it is necessary or efficient to externalize all risks in order to minimize them. As Mr. Lyash explained:

> Mitigating risk does not equate to establishing a fixed-price contract and paying a high premium for someone else to take that risk. Mitigating risk is a much broader topic than that that gets mitigated through planning, completion of engineering, procurement and delivering in advance of all spare parts, development and testing of tooling, training and qualification of workforce.
>
> So there -- identification of risks and specific mitigation of them, so there's a much broader risk mitigation strategy implied and asked for in the [2013 LTEP] than just contracting strategy, although contracting strategy is certainly an element of that risk. And in developing a contract strategy, it takes careful evaluation of who is best in a position to identify, characterize, mitigate, and control the risk, and setting up a structure where that party is charged with that responsibility, and that helps drive the notion of what the target price, what the fixed price or firm price, and what to do as cost plus. And that is embedded in this overall strategy to minimize risk to the company and ultimately to the customer. (Tr. Vol. 1, p. 162 (emphasis added)).

GEC’s interpretation of the 2013 LTEP principle effectively requires OPG not to *minimize* risk, but to *eliminate* risk through the purchase of insurance, no matter the cost. OPG respectfully submits that that is not what the 2013 LTEP principle says. Moreover, GEC’s submission is at odds with the expert evidence of Schiff Hardin in this proceeding, who noted that: “Assuming OPG could even find a single contractor to take on all of the risk in an EPC model, the price would likely be extremely high or even prohibitive. An owner, particularly on a large mega-program, cannot void itself of all risks…” (Ex. M1, EP-11).

In Faithful+Gould’s (“F+G”) benchmarking report on contracting strategy and overhead and profit levels for large-scale international projects, F+G confirmed that the overall contracting approach being adopted for the RFR work bundle is in line with the overall contracting approach being adopted in other complex long term projects (Ex. L-4.3-15 SEC-14, Attachment 1, p. 7). Similarly, F+G cautioned against the use of fixed price contracts, noting that while other projects have used fixed price contracts, “If the Fixed Price is negotiated with the incumbent Contractor, it may still be high and still subject to Change Orders” (Ex. L-4.3-15 SEC-14, Attachment 1, p. 6). F+G also observed that disputes arising over fixed price contracts are “causing Owners to be concerned that they continue to be exposed to risks they anticipated were covered by the original Fixed-Price Agreement. This is common where scope is not well defined, or when these risks become too great for the Contractor to absorb” (Ex. L-4.3-15 SEC-14, Attachment 1, p. 13). Finally, F+G observed that most of the large complex projects or portfolios of programs addressed in their study are adopting either a target cost or “hybrid contract”, which is defined as “a mix of pricing mechanisms required to allocate risk where best placed for different project elements” (Ex. L-4.3-15 SEC-14, Attachment 1, p. 8).

OPG submits that it has adopted a prudent and reasonable contracting strategy for each work bundle, taking into account the need and ability for OPG to transfer risk to its contractors as balanced against the benefit of achieving a lower contract price or target cost. For work that exhibits high levels of complexity and uncertainty, such as with the RFR work bundle, the transfer of significant pricing risk to the contractor was less feasible. Nevertheless, OPG reviewed what work within the RFR bundle would be suitable for a fixed price or reimbursable costs/cost plus mark-up pricing mechanism. OPG’s careful selection of contracting strategies and pricing models takes into account the risk profile of each segment of work. As noted in OPG’s AIC, OPG is employing contracting strategies that independent experts found to be appropriate and reasonable, and that meet the regulatory standard of prudence (AIC, p. 41). OEB staff, and those intervenors adopting their submissions, also accept that the multi-prime contractor model is appropriate for the DRP, and that the strategy applied by OPG is a reasonable approach for a project the size and complexity of the DRP (OEB staff argument, p. 41).

Off-ramps

SEC submits that OPG’s DRP off-ramps are “in practice, illusory”, and that OPG has not adequately built in contractual provisions that allow it to trigger an off-ramp. With respect to consistency with 2013 LTEP, SEC submits that OPG should have not only unlapped Units 2 and 3, but also inserted a significant window between the two to allow OPG to cancel contracts with its contractors right up to the completion of Unit 2 (SEC argument, Section 4.6).

OPG submits that SEC has misunderstood the off-ramps available in the DRP contracts, and also notes that there are costly consequences and fundamental problems with the proposal that SEC has put forward. OPG's contracts all include a termination for convenience clause that allows OPG to take an "off-ramp" on any contract at any point (Ex. D2-2-3, p. 6). Should OPG encounter significant problems in executing the Unit 2 refurbishment, OPG has the ability to use the termination for convenience clauses and terminate contracts at any time. Upon termination for convenience, OPG will be responsible for certain types of direct damages, including costs for work performed to date, equitable portion of fees payable on the next milestone date, costs for work in progress at the time of termination, and reasonable direct damages such as out of pocket costs for demobilization (Ex. L-4.3-1 Staff-50, part a). However, OPG will not be responsible for full contractual damages. Thus, OPG is not restricted from terminating contracts simply because a decision to go forward with Unit 3 refurbishment has been made.

The insertion of a "significant window" between the Unit 2 and Unit 3 refurbishments would have resulted in significant risks for the DRP. As OPG indicated in its Execution Phase business case, transition periods between unit refurbishments can be of significant risk:

> The risk is that due to the current un-lapped Unit 2 schedule, after the majority of the field work is complete on Unit 2, and prior to their requirement for Unit 3, key resources might leave OPG and not return to execute Unit 3. This could result in re-training of staff and reduced opportunity for performance improvement, as well as the potential loss of 'project momentum' (Ex. D2-2-8, Attachment 3, p. 31).

To address this risk, OPG has included contingency for trough management costs to retain critical trades and leadership resources that may otherwise leave the program and not be available to return to work on Unit 3 (Ex. D2-2-8, Attachment 1, p. 31; Ex. L-4.3-1 Staff-67). If there was a larger window, not only would OPG need to carry additional trough management costs in order to keep contractor staff engaged for a longer duration of time, but it would also need to carry additional costs internally, such as project management and overhead costs.

OPG also must manage the remaining life of the units awaiting refurbishment. For example, based on current assessments, without refurbishment, Unit 3 would need to be shut-down in early to mid-2020 (Ex. L-4.3-8 GEC-9). A "significant window" between Unit 2 and Unit 3 refurbishment could potentially result in Unit 3 sitting idle, which could impact the cost and schedule to refurbish it. There would also be rate impacts due to a longer period where a unit is not producing power, but nevertheless incurring ongoing operations and maintenance costs.

OPG expects that any decision to exercise an off-ramp will not be taken lightly or without notice (Ex. L-4.3-1 Staff-44(b)). Given the many layers of oversight in place over the DRP, including from the Ministry of Energy, OPG submits that any need to off-ramp the program will be discussed, reviewed and considered far in advance of a decision being made.

Finally, on a fundamental level, OPG respectfully submits that the 2013 LTEP requires OPG to "entrench appropriate and realistic off-ramps"; it does not contain "on-ramps" whereby each subsequent unit refurbishment requires a new approval. Absent an off-ramp being taken, the DRP must continue to proceed to complete the refurbishment of the four units, on time, on schedule, with quality, and in the most cost-efficient and safest manner, all of which is in the interests of ratepayers.

Unit-over-unit Productivity Gains

SEC submits that the contract amendment with respect to unit-over-unit productivity gains was inappropriate as ratepayers do not benefit from this amendment, and that there was "no compelling reason to further concede productivity improvements" (SEC argument, paras. 4.11.1-4.11.4).[41] SEC's position is wrong. The productivity gain amendment that SEC refers to was included within Amendment 4 to the RFR Contract. This was a large amendment to incorporate the Execution Phase plan, which includes the Execution Phase cost estimate, schedules (milestone, target and submittal), and risk register (Ex. L-4.3-15 SEC-22, Attachment 2, Tab 19). As explained below, and validated by independent experts, the cost and schedule improvements that OPG received for reducing, but not eliminating, unit-over-unit productivity gains provide significant ratepayer benefits.

SEC has singled out one aspect of a very large amendment that resulted in OPG setting very aggressive target cost values for the SNC/AECON JV. In focusing only on this single provision, SEC has ignored the interrelationships among the many changes that together produce

[41] OPG notes that paragraph numbers 4.11.1 through 4.11.6 are duplicated in SEC's submissions. Here, OPG is referring to the second reference to para. 4.11.6 on page 49 of SEC's argument.

significant benefits for ratepayers. As OPG indicated in Ex. D2-2-8, the Execution Phase cost was arrived at with the SNC/AECON JV through a very rigorous vetting process (Ex. D2-2-8, pp. 11-13). As part of the negotiation process, the SNC/AECON JV had sought to remove the productivity factors given that OPG had insisted that some schedule contingency be removed. OPG, however, maintained the importance of the productivity gains provision, and eventually succeeded in lowering the percentages in the provision rather than eliminating it altogether (Ex. L-4.3-6 EP-15). As Mr. Reiner explained:

> So the outcome of all of this is the outcome of a negotiated process that has many puts and takes. The primary reason why we had agreed to lower these percentages is we took a significant amount of schedule duration out of the target price in our discussion, so back to the drive towards P50 and a schedule that is relatively aggressive. And the target that we used for schedule for the RFR contract was the best performance that we had seen in refurbishments, which is the Wolsong refurbishment. So we took an approach that the first unit at Darlington will do better than the last unit that was refurbished. Therefore, the opportunities to get the unit-over-unit improvements were not as significant, and that was essentially the Trade-off that was made. (Tr. Vol. 3, p. 85).

Concentric was retained to provide an independent assessment on whether the final contract for the RFR is reasonable and prudent. Concentric concluded that, based on OPG's activities with regard to amending and finalizing the RFR contract, the terms of the RFR contract, including the target price and the allocation of risk, are both reasonable and meet the regulatory standard of prudence (Ex. D2-2-11). Within this assessment, Concentric expressly acknowledged that the existing productivity gains provision in the RFR contract continues to be a key risk sharing term in the amended contract (Ex. D2-2-11, Attachment 1, p. 7).

Benchmarking on Profit and Overhead Margins

SEC submits that the OEB should look at the profit and overhead built into the DRP's target price contracts and compare it to the benchmarks of other nuclear projects, notably, the F+G report filed at Ex. L-4.3-15 SEC-14, Attachment 1 (SEC argument, paras. 4.11.1-4.11.6).[42]

At the core of SEC's concern is that, using the numbers presented in Ex. JT1.6 for the profit and overhead values in the DRP contracts, OPG's contracts appear to be above the median/mode for "Overall Markup" values in the F+G Report for nuclear projects. SEC

[42] OPG is referring to the first reference to para. 4.11.6 on page 48 of SEC's argument.

therefore submits that, “the contract contains atypical level of combined markup” (SEC argument, para. 4.11.6).[43]

OPG submits that the numbers presented in Ex. JT1.6 are not directly comparable to those in the F+G Report for the following reasons:

1. As OPG stated in the Undertaking response to Ex. JT1.6, because many of the contracts consisted of mixed pricing models, including fixed price portions where OPG cannot determine the profit and overhead included, it is not clear what the *overall* markup is in the DRP contracts.

2. F+G itself acknowledges that there are difficulties with benchmarking “corporate overhead” costs, given that:

    a. contracts often only specify profit margins,

    b. there are varying definitions from contract to contract on the specifics of what comprise “corporate overhead” costs, and

    c. corporate overheads can be heavily influenced by the cost of local engineering contractors (Ex. L-4.3-15, SEC-14, Attachment 1, pp. 9, 18).

3. While some of the components of the DRP contracts are higher than the mean/mode values in the F+G report, they are nevertheless within the range of results included in the F+G report and thus not accurately characterized as “atypical.”

4. The overall markup is only one portion of the contract. There are other components of the contracts where the contracts perform better than the benchmark results, such as the significant fee-at-risk provisions in the DRP contracts. Although OPG may be higher on the benchmark for profit and overhead, more of these funds are at risk.

5. Finally, as Mr. Reiner explained during the proceeding, the benchmark population used by F+G went beyond the Canadian industry, and because the Canadian regulatory requirements mandate a quality management program to be in place, there can be significant additional costs for operating in Canada.[44]

SEC ultimately acknowledges that the comparison against the F+G report does not provide a sufficient basis for SEC to draw any conclusions regarding the reasonableness of the contract overhead and profit levels (SEC argument, para. 4.11.6).[45]

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[43] OPG is referring to the first reference to para. 4.11.6 on page 48 of SEC’s argument.
[44] SEC acknowledges this position, but submits that that is only expected to impact total cost of the contract. OPG disagrees and notes that the implementation of a quality management program would add overhead costs.
[45] OPG is referring to the first reference to para. 4.11.6 on page 48 of SEC’s argument.

Incentives

CCC submits that OPG was unable to demonstrate that OPG has incentives to deliver Unit 2 or the DRP lower than budget, except for some individual executive incentives (CCC argument, p. 8). EP acknowledges that there are incentives to ensure that OPG meets its budget and schedule targets as they relate to the DRP, but that there is not a strong incentive for OPG to do better than its base estimate at P90 (EP argument, para. 3.18). EP recommends that the OEB put in place a 50/50 Earnings Sharing Mechanism wherein OPG and the ratepayers equally share in the Unit 2 contingency used below the P90 level, and any costs incurred above the P90 would continue to flow through the CRVA (EP argument, paras. 3.19 to 3.27). PWU expressly submits that OPG has the incentives to deliver the DRP at or under budget (PWU argument, para. 19).

As outlined in OPG's AIC and throughout this proceeding, OPG has extensive incentives in place to deliver the DRP safely, on time or earlier, on or under budget, and to the requisite quality level (AIC, pp. 61-62). As Mr. Lyash characterized the matter, the DRP is a destiny project for OPG. This is demonstrated through the company's focus on the DRP, and is reflected in the corporate scorecard. Contrary to CCC's submissions, the corporate scorecard does not equate to "minor incentives… wherein individual executives at OPG earn their annual incentive". Instead, in recognition of the DRP's importance, the DRP performance metrics form part of the corporate-wide scorecard that impacts the incentives for all management staff at OPG, which at the end of 2015, included more than 1000 employees (Tr. Vol. 4, pp. 93-94; Ex. L-6.6-2 AMPCO-134). Individuals directly involved in the DRP have their performance further tied to the overall performance of the DRP (Tr. Vol. 4, p. 94).

Furthermore, the scorecard metrics are not targeted to meet the P90 cost and schedule, but to beat it. The P90 values represent the "threshold" values for the DRP metrics, and in order for OPG's management employees to earn any incentive at all from the DRP metrics, the company has to beat the threshold, and is incented through a graded approach up to the "stretch" targets (Tr. Vol. 4, pp. 97-98). In addition, the threshold and stretch targets are adjusted based on actual work completed and risks that in fact materialize in the year to ensure that the incentives are based on the reality of how the DRP is executed (Tr. Vol. 4, pp. 95-99). As such, the company as a whole is incented to beat the P90 estimates.

CCC also submits that the only incentive for OPG to come at least on budget is to avoid regulatory scrutiny (CCC argument, p. 8). OPG agrees that regulatory approval is one incentive, as Mr. Lyash set out in the proceeding (AIC, pp. 61-62). However, that is not the only incentive in place for OPG. Beyond the oversight provided by OEB regulation, OPG is subject to extensive oversight in the execution of the DRP, including by OPG's Board of Directors (which has retained independent experts to provide oversight) and the Province (which also has retained independent experts). All of this oversight drives to a single outcome – safely and with quality, complete Unit 2 refurbishment as quickly and at the lowest possible cost. OPG is keenly aware that if it can do better than the forecast schedule and cost, OPG will build confidence in its ability to execute the full program, which will significantly improve the likelihood that the Province will continue to support refurbishing the remaining Darlington units.

Similarly, OPG submits that EP's proposal to implement a 50/50 Earnings Sharing Mechanism to encourage OPG to beat its P90 estimate is both unnecessary and inappropriate for Unit 2. As Mr. Lyash noted, a financial incentive is not required or necessarily in the best interests of ratepayers to incent OPG to perform:

> My point was that putting a -- putting a capital incentive on a project whose value is delivered over 30 years and that value is so dependent on the safety, the reliability, and the cost-effectiveness of the unit post-refurbishment would not be an incentive that would necessarily be in the customer's long-term best interests (Tr. Vol. 2, p. 126).

The OEB should guard against the implementation of an incentive that is strictly focused on cost and neglects the importance of safe and quality execution of the DRP.

Furthermore, OPG notes that contingency in the DRP is probabilistically determined, such that OPG carries contingency based on the probability of risks occurring. However, as OPG noted in this proceeding, if a risk occurs, even if there was only a 40% chance of the risk occurring, OPG will incur the full cost of that risk event (Tr. Vol. 4, pp. 63-64). To that end, if OPG delivers the Unit 2 refurbishment for less than $4,800.2M, the unused contingency will be returned to the Program's contingency and be available to future units. While OPG may reforecast the program to be lower than $12.8B in the future based on detailed analysis of the costs that are expected to materialize, it would not be appropriate to do so at the end of Unit 2 refurbishment. As well, OPG notes that EP's proposed Earnings Sharing Mechanism may not be compliant with O. Reg. 53/05, which requires that the OEB ensure that OPG recovers the prudent costs of the DRP.

As Mr. Lyash confirmed, the entire set of OPG incentives reviewed during the hearing work together:

> Perhaps you have a particular incentive in mind that I haven't stated, but I think the incentive to run the company to maximize the opportunity for us to invest, to earn a net income and return on that, to be able to continue with the execution of this destiny project, to be able to deliver this at the lowest possible price and contribute to holding down customer rates as a reputational matter that creates opportunity for us to make future investments in the long-term, these are all very real and tangible incentives for OPG (Tr. Vol. 1, p. 122).

OPG submits that it has a complete set of meaningful and measurable incentives in place to deliver the DRP at the lowest cost, on the earliest date, safely and with quality, and that the OEB should not accept EP's Earnings Sharing Mechanism.

F&IP and SIO

Various intervenors have made statements regarding OPG's F&IP and SIO related projects and used the process of their development and execution to imply conclusions about the successful completion of the Unit 2 refurbishment. However, as noted, they have done so without taking into account the key distinctions between the F&IP and SIO related projects and Unit 2. As stated in evidence:

> When you look at -- in their entirety, the modifications that need to be made to the Darlington facility in order to allow it to operate for another 35 years, the bulk of the complexity lies in the SIO and in the D20 storage projects. They are first of a kind. They are being constructed under a different set of regulatory standards than the initial plant was constructed, much more rigid regulatory standards. And they're also being constructed there -- many of these are civil projects being constructed in what we call a brownfield environment, an existing facility that introduces risk. So there is a significant element of risk that sits with those projects and complexity that sits with those projects that you don't see in the execution of the refurbishment. And even though the dollars are larger in refurbishment, it almost seems counterintuitive. But the nature of the work is very, very different. (Tr. Vol. 1, p.58; see also Ex. D2-2-10, p. 11 (emphasis added)).

Because of the nature of these projects, their engineering and design evolved over time creating variances between their initial estimates and subsequent estimates. The fact that engineering and design was refined does not mean that the work was not required or imprudently undertaken to complete the project as needed. Putting aside the Heavy Water Storage Facility project, which is the subject of a later proceeding, overall performance by OPG in respect of the F&IP and SIO portfolio projects has been within a reasonable range (especially given the complexity of the projects) with a variance of approximately 12% - over four times less that the number suggested by SEC (SEC argument, para. 4.7.3).

Third Emergency Power Generator

OEB staff submit that if the OEB approves OPG's requested in-service amount for the Third Emergency Power Generator ("EPG3"), the OEB would forgo the opportunity to consider whether the cost variance between the initial execution estimate and the proposed in-service amount was prudently incurred. Furthermore, OEB staff submits that "there very well could be management imprudence that caused a portion of the cost overrun to be experienced" (OEB staff argument, p. 44). As such, OEB staff submits that only the initial project estimate should be approved in this proceeding. SEC similarly agrees with OEB staff's approach, but notes that the reduced in-service amount should account for the partial in-service amounts that have already gone into service (SEC argument, para. 4.8). CME submits that the entire variance between the initial project estimate and the actual project cost should be disallowed (CME argument, para. 189). Although EP indicates its support for OEB staff's submissions, EP submits that the OEB should approve the proposed in-service amount of $105.3M, with a full prudence review of the variance between that figure and the eventual final cost at the future CRVA proceeding (EP argument, para. 3.29).

OEB staff state that there "could" be imprudence. Their assertion is entirely speculative since OEB staff have not provided any evidence on which to provide a basis for disallowance. In effect, OEB staff are requesting that the OEB deny the in-service amount requested of $115M in order to permit a review in the future as part of the disposition of the CRVA between the amount of $77.2M, which is the initial full release amount cited by OEB staff, and whatever is the ultimate in-service amount at the completion of the project. The desire of OEB staff to defer the consideration of in-service amounts until a later date is not an appropriate basis not to place the prudent and reasonable in-service amount of $115M into service.

To clarify, the initial estimate for EPG3 proposed by OEB staff is incorrect. The initial estimate at completion based on the project's first approved Gate Progression Form was $88.2M (Ex. L-4.3-2 AMPCO-30, Chart 3). The $77.2M cited by OEB staff from Ex. D2-2-10, Table 2 represents the cumulative release to that point in time. The in-service amount proposed by OPG for EPG3 is, as Ex. D2-2-10, Table 2 notes, the total project cost at RQE of $115M[46]. For the same reasons, the numbers cited by SEC at paragraph 4.8.2 of its argument are also incorrect. Using SEC's argument, the amount that SEC submits should be approved would be the initial estimate of $88.2M. Given the partial in-service amount of $9.7M in 2015, the incremental approval under SEC's proposal would be for $78.5M.

As stated by Mr. Reiner:

> So some of the early estimates that were in our systems were based on some -- when I talk about the third emergency power generators, as an example, was based on preliminary estimates done prior to the completion of engineering. Our focus was on getting enough planning and getting enough engineering done so that we could put a reliable estimate in place by the end of 2014 and monitor performance to that (Tr. Vol. 3, p. 131).

The changes in project cost estimates represent estimating progression as part of the project development process to refine scope, complete design activities, and fully assess the projected execution costs. The estimate of $115M was the in-service amount for EPG3 factored into the RQE for the DRP. As OPG stated in the proceeding, the correct cost baseline to evaluate the DRP on is the RQE:

> ... that's precisely why we have taken the time to plan this, and even at the time of the last hearing, we said at the time of the release quality estimate that will be the project estimate that we commit to executing refurbishment under. And leading up to that point, they were just points in time of where the development of the project was at (Tr. Vol. 1, p. 69).

The OEB staff's as well as SEC's and EP's proposed disallowance is based solely on the notion that there has been a variance from the initial project budget. However, this is a variance that OPG has fully justified as an outcome of the planning process. Furthermore, OPG submits that the opportunity to review the cost variance between the initial execution estimate and the

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[46] This is comprised of a $9.7 M actual in-service amount in 2015 (Ex. L-2.2-1 Staff-8) and the $105.3 M proposed in-service amount during the test period (Ex. D2-2-10, Table 2).

project estimate at RQE was available in this proceeding. OPG presented the specific reasons for the EPG3 variance from the initial estimate in its prefiled evidence (Ex. D2-2-10, pp. 21-22), and parties explored the provided reasons in detail throughout the proceeding (see e.g., Ex. L-4.3-2 AMPCO-98; Ex. L-2.2-1 Staff-8; Tr. Vol. 3, pp. 131-134; Tr. Vol. 4, p. 60-62; Tr. Vol. 5, p. 65).

As Mr. Reiner explained with respect to the cost variances between the initial estimates and the values at RQE for the F&IP and SIO, the revised estimates from the initial budget reflects completion of engineering and the resulting full understanding of the actual work required to complete the projects:

> We've said this many times, but I want to say it again. The issue we had is point estimates were put into business cases before sufficient work was done to actually understand what the cost would be. The cost of the projects is directly reflective of the work that's needed. …
>
> The error that was made is the cost estimates -- point estimate without ranges of uncertainty were introduced for these projects prior to sufficient work being done to actually know what a realistic cost range around these projects is. (Tr. Vol. 3, pp. 132-133 (emphasis added)).

EPG3, like the other F&IP and SIO projects, was an early adopter of the gated process. As discussed above in Section 5.4, OPG's gated process is a project management tool that controls the progression of a project from an initiation phase (Gate 1), through progressive gates of development and definition (Gate 2), to eventual execution (Gate 3) and ultimate completion (Ex. L-4.3-1 Staff-48, Attachment 20). At each successive gate the plans and designs progress in detail. However, the end result of each gate, except for completion, is a cost estimate with an uncertainty range around it.

As noted above, although a point estimate was stated for EPG3, there remained inherent uncertainty within the estimate, and it would have been better to state a range. The fact that OPG did not state a range of variability around the estimate is not a basis for a disallowance. OPG acknowledges that any amount greater than the in-service amount of $115M for the EPG3 will be recorded in the CRVA. These amounts should be included as part of any future consideration of the amounts related to DRP as a whole, since, as stated on the record, the project's increased cost is appropriately funded by the contingency that is held within the DRP (Tr. Vol. 3, p. 14).

OEB staff and the other parties have presented no evidence that the engineering and construction was imprudent to justify their proposed disallowance. In fact, the work done and the cost incurred are required for the project. The variance is between the initial execution estimate and the RQE value OPG sought as the in-service amount arose from the estimating process as part of OPG's project budgetary release process and the further refinement of the engineering and scope definition plans. While OPG acknowledges that any portion over OPG's proposed in-service amount is subject to the CRVA, as noted above OEB staff have presented no reason for using an incorrect estimate as the in-service amount in this Application.

6.0 PRODUCTION FORECASTS

6.1 Issue 5.1

Primary: Is the proposed nuclear production forecast appropriate?

OPG is seeking approval of the nuclear production forecast shown in Chart 6.1 (Ex. E2-1-1, Table 1). The basis for OPG's forecast for the IR term is summarized in the AIC at pages 69-72.

Chart 6.1
Production Forecast

(TWh)	2017	2018	2019	2020	2021
Darlington	19.0	19.3	19.7	17.7	16.6
Pickering	19.1	19.2	19.4	19.6	18.8
Total[1]	38.1	38.5	39.0	37.4	35.4

1: Total may not sum due to rounding. OEB staff and OAPPA incorrectly present total production of 39.1 TWh in 2020 and 37.3 TWh in 2021, which appears to be due to rounding (OEB staff argument, Table 17, p. 68, OAPPA argument, p. 4).

OEB staff propose that OPG's Pickering production forecast be increased by 0.5 TWh in 2017, 2018 and 2019 (OEB staff argument, p. 69). Based on OEB staff's analysis, LPMA goes further in proposing increases to Pickering's production forecast of 0.9 TWh in 2017, 0.8 TWh in 2018 and 0.6 TWh in 2019 (LPMA argument, p. 13). OAPPA submits that Darlington's production forecast should be increased by no less than 2.95 TWh over the IR term (OAPPA argument, p. 6). This submission is supported by LPMA (LPMA argument, p. 14).[47]

As the material below confirms, the evidence does not support the proposed adjustments to OPG's production forecast, either for Pickering or Darlington. Instead, the OEB should adopt OPG's production forecast, as it is based on a well developed and rigorous planning methodology that is unchanged from the production forecast methodology that the OEB accepted in EB-2013-0321.

OEB staff submit that OPG's Pickering production forecast is too low; that OPG's planned outage days at Pickering are too high; that OPG's increase in planned outage days forecast is not justified; and, that Pickering mid-cycle outages do not reflect a "lessons learned" approach to outage planning (OEB staff argument, pp. 70-74). LPMA generally agrees with these submissions. In OPG's view, the evidence is to the contrary: the Pickering production forecast is appropriate and is in fact consistent with observed historical trends once PEO-related outages are considered; the planned outage days forecast is reasonable when the impact of historical forced extensions to planned outages ("FEPO") and the 2021 vacuum building outage ("VBO") are taken into account; and, the production forecast does in fact reflect key lessons learned.

OEB staff attempt to show that OPG's IR term production forecast for Pickering is low relative to historical trends. In support of this effort, OEB staff have produced a graph showing actual Pickering production from 2008 - 2016, OPG's 2017 - 2021 production forecast for Pickering and OEB staff's proposed adjustments to that forecast in 2017, 2018 and 2019 (OEB staff argument, p. 70). What OEB staff do not acknowledge, however, is that OPG has consistently set challenging production targets using the same methodology. OPG's actual production during this period has been below OPG's forecast and further below the higher forecasts adopted by the OEB (Ex. E2-1-1, Chart 2). OPG has experienced significant revenue shortfalls due to these variances. As shown on Ex. E2-1-1, Chart 2, the average annual production

[47] VECC agrees with the reasoning and positions of other parties regarding the nuclear production forecast (including the resulting adjustment to nuclear fuel costs) (VECC argument, para. 4). VECC's submission will not be mentioned further in this section.

shortfall over the 2008-2015 period was 3.2 TWh. This resulted in an average negative revenue impact of $154.0M borne each year by OPG's shareholder. In 2016, OPG's production was 1.2 TWh lower than the amount of production forecast in OPG's 2016-2018 Business Plan, which is the source of the production forecast used in this Application (Ex. J12.7). This record shows that OPG has historically set consistently challenging production forecasts.

OEB staff attempt to compare OPG's IR term production forecast for Pickering to actual production by comparing just two years. This comparison is selective as it compares 2015, the year with the highest actual production since OEB-rate regulation began, to 2017, the year with the second lowest production in the IR term. Based on the comparison of only these two years, OEB staff claim that the production forecast has declined by 2.1 TWh or 10% (OEB staff argument, p. 70). However, when Pickering's average annual production over the entire 2008 - 2016 period (20.1 TWh per year) is compared to the average annual production forecast during the IR term (19.2 TWh per year), the variance is cut by more than half to only 0.9 TWh per year or approximately 4%.

Citing average annual historical production at Pickering, LPMA submits that the OEB should approve a forecast of 20 TWh per year for Pickering in 2017, 2018 and 2019 (LPMA argument, p. 13).

However, this decline in Pickering production in the IR term compared to the historical period is primarily attributable to the outages required to extend Pickering's operation to 2022/24. If the 7.5 TWh production losses associated with the 637 PEO-related outage days in 2017-2021 were excluded from the IR term forecast, average annual production would actually be 0.6 TWh, or 3%, higher than average annual 2008-2016 production.[48]

OEB staff's assertion, supported by LPMA, that OPG's Pickering production forecast does not reflect initiatives undertaken to improve reliability at Pickering is incorrect (OEB staff argument, p. 70). Rather, the Pickering production forecast is predicated on a challenging 5% forced loss rate ("FLR") target reflecting expectations of reduced volatility in performance as a result of equipment reliability and fuel handling improvement initiatives (Ex. E2-1-1, p. 4; Ex. L-5.1-1

[48] 0.6 TWh = 19.2 TWh per year test period production forecast + (7.5 TWh per year [from Ex. E2-1-1, p. 4] / 5 years) – 20.1 TWh per year actual (2008-2016).

Staff-83). As recently as 2014, FLR at Pickering was 10.7% (Ex. E2-1-1, p. 9), and over the 2010 to 2015 period FLR averaged 8.5% (Ex. E2-1-1, Chart 4).

OEB staff's belief, shared by LPMA, that Pickering's planned outage days during the IR term are too high compared to the last five years (2012-2016) does not acknowledge the rigorous process that OPG uses to develop its planned outage duration forecast and is based on an incomplete analysis, as further described below.

As OPG noted in AIC (pp. 69-70), OPG's planned outage schedule identifies the number of days required for inspections and maintenance activities to ensure continued safe, reliable and long-term operation (Ex. E2-1-1, p. 6). Outage durations are determined based on the scope of work defined for each outage while considering recent benchmarking efforts, industry best practices and the Nuclear business' commitment to continuous improvement (Ex. E2-1-1, p. 5). In EB-2013-0321, OPG refined its nuclear production forecast approach to more fully and realistically recognize the scope, risks and complexity of work performed during outages, and where possible, base the forecast on actual experience with similar work performed at OPG and other organizations (Tr. Vol. 12, p. 125). In EB-2013-0321, the OEB accepted OPG's approach (EB-2013-0321 Decision with Reasons, pp. 39-40).

OPG submits that OEB staff's comparison of forecast to actual planned outage days at Pickering is flawed (OEB staff argument, pp. 71-72). The comparison is inappropriate because it does not consider: (a) FEPO-related outage days and (b) outage days associated with the 2021 VBO. Excluding these factors produces an inaccurate comparison that makes OPG's planned outage day forecast for Pickering appear to be excessive when it is actually consistent with historical trends.

In order to properly measure planned outage days against historical results, planned outage days should be compared to actual outage days, which is the sum of actual planned outage days and FEPO days. The omission of FEPO days from OEB staff's analysis is material as there were a total of 383.2 FEPO days at Pickering during the 2012-2016 period (Ex. J12.9, Attachment 1).

When OPG calculates planned outage durations, it includes production allowances to reflect the risk of generation loss due to FEPO (Ex. E2-1-1, pp. 7-8, Tr. Vol. 12, p. 122). This approach is consistent with the approach OPG used and the OEB accepted in EB-2013-0321. Inclusion of production allowances is necessary to fully and realistically recognize the scope and complexity of planned outages that will be undertaken in 2017-2021 to address equipment reliability, equipment aging and parts obsolescence on OPG's aging nuclear reactors (*Id.*).

Similarly, OEB staff compare 2017-2021 forecast planned outage days at Pickering to the years 2012-2016. However, the 2017-2021 period includes 120 VBO-specific outage days[49], while the 2012-2016 period has no VBO-related outages (Ex. J12.10, Attachment 1). Given the number of outage days that a VBO requires, OPG's forecast appears to be excessive when it is actually in line with historical trends.

In Chart 6.2 below, OPG has reproduced Table 18 from OEB staff's argument (OEB staff argument, p. 71) to reflect the impact of accounting for FEPO and VBO-related outages on an "apples to apples" basis (all the data is from Ex. J12.9, Attachment 1).

[49] The six-unit VBO at Pickering in 2021 is comprised of four 30-day outages on units 4, 6, 7 and 8, as well as VBO-related work that will be carried out during planned outages on units 1 and 5 (Ex. J12.10 Attachment 1).

Chart 6.2
Updated OEB Staff Table 18

Pickering Planned Outage Days (PO DAYS) Last 5 Years (Actual) vs Test Year (Forecast)				
	TOTAL PLANNED OUTAGE DAYS 2012-2016 (ACTUAL DAYS)[a]	TOTAL PLANNED OUTAGE DAYS 2017-2021 (FORECAST DAYS)	DIFF (DAYS)	DIFF %
PNGS U1	234.7	569.9	335.2	143%
PNGS U4	231.1	424.7	193.6	84%
PNGS U5	193.7	506.0	312.2	161%
PNGS U6	216.9	455.7	238.9	110%
PNGS U7	335.8	325.9	-9.8	-3%
PNGS U8	339.1	369.1	30.1	9%
TOTAL (PO DAYS)	1,551.2	2,651.3	1,100.1	71%
PEO PO DAYS		637		
EXCL. PEO PO DAYS	1,551.2	2,014.3	463.1	30%
INCL. FEPO DAYS	383.2			
EXCL. VBO PO DAYS		120		
TOTAL	**1,934.4**	**1,894.3**	**-40.1**	**-2%**

a: Actual planned outage days include outages associated with Pickerng Continued Operations

As shown in Chart 6.2, when FEPO and VBO-related outages are properly considered, forecast planned outage days at Pickering (1,894 days) are actually lower than historical planned outage days (1,934 days), contrary to the claims made by OEB staff. In fact, there are about 40 less planned outage days in total during 2017-2021 than there were in 2012-2016 when the comparison is done on an “apples to apples” basis. As shown in Chart 6.2, this represents a 2% decrease rather than the 30% increase reflected in OEB staff’s comparison.

OEB staff also compare OPG’s forecast of Pickering planned outage days with actual Pickering planned outage days in an attempt to show that OPG over-forecasts planned outage days (OEB staff argument, p. 73, Table 19). Again, when FEPO is correctly taken into account, a different picture appears. In Chart 6.3 below, OPG has reproduced the top line of Table 19 from OEB staff’s argument and modified it to accurately compare forecast planned outage days to the sum of actual planned outage days and FEPO days. The result is similar to the result OPG obtained above. When FEPO is properly considered, OEB staff’s conclusion that OPG over-forecasts planned outage days is shown to be in error. Instead, as Chart 6.3

demonstrates, OPG's forecast planned outage days over the 2008-2016 period have been lower (2,774 days) than the sum of actual planned outage days and FEPO days over the same period (3,082 days) (Ex. J12.8, Attachment 1).

Chart 6.3
Updated OEB staff Table 19

Pickering Planned Outage Days					
	Forecast PO Days	Actual PO Days + FEPO	Variance	Variance	Notes
Forecast Accuracy (2008-2016)	2,774	3,082	-308	-11.1%	Forecast Lower than Actual by 11.1%

OEB staff question OPG's claim that it applies lessons learned from previous outages and other relevant experience when developing its production forecast (OEB staff argument, p. 74). In particular, OEB staff advance this view with respect to mid-cycle outages at Pickering, which they believe "do not reflect a lessons learned approach to outage planning". To support this view, OEB staff reference a table that OPG produced in response to Ex. L-5.1-5 CCC-24, Attachment 1 which summarizes planned outages during the IR term, including mid-cycle outages at Pickering. OEB staff's presumption is that "labeling these outages generically as 'mid-cycle' is indicative that similar maintenance and procedures will be performed during each of these scheduled outages." This single reference appears to be the foundation for OEB staff's claim that mid-cycle outages do not reflect a lessons learned approach (*Id.*). Below, OPG clarifies several aspects related to mid-cycle outages to counter OEB staff's submission.

The fact that several outages are labeled "mid-cycle" does not mean that similar maintenance and procedures will be performed during each of the outages. The term "mid-cycle outage" refers to the fact that each of these planned outages is expected to occur mid-way through the planned outage cycle for Pickering. This consistent timing does not indicate that the same work will be performed during each of these outages.

To the contrary, OPG's witnesses explained during the oral hearing that the work performed during each mid-cycle outage will be different, as the work is unique to the outage and time frame given the particular configuration of the reactor at that point in time (Tr. Vol. 12, pp. 145-146). Mid-cycle planned outages were introduced at Pickering Units 1 and 4 starting in 2012 to allow for additional preventive maintenance, which is expected to lessen the risk of forced outages as the Pickering plant ages (Ex. E2-1-1, p. 9). Mid-cycle outages during the IR term are expected to address various inspection and maintenance work such as completing outstanding corrective maintenance backlogs (Ex. J12.12). These outages will provide OPG with higher confidence that the units will operate reliably by reducing the potential for forced outages.

OEB staff also question whether OPG had applied lessons learned to find efficiencies when replacing primary heat transport ("PHT") motors at Darlington, but they do not recommend any changes to the Darlington production forecast as a result (OEB staff argument, p. 74). In particular, OEB staff appear unconvinced of OPG's claim that 20 days for each PHT motor replacement is an efficient duration that incorporates lessons learned. OEB staff state that the 28-day PHT motor outage in 2015 "offers no guidance of whether a 20 day outage reflects the limit for marginal efficiency increases" (OEB staff argument, p. 75). OPG submits that this doubt is misplaced based on the requirements of these types of outages. The OPG witness explained why such outages require no less than 20 days to complete (Tr. Vol. 14, pp. 20-22). These reasons include the fact that work cannot start until the reactor fuel has cooled down, the challenges associated with maneuvering and integrating such a large and complex piece of machinery and, critically, that OPG has already significantly optimized the outage work and reached a limit to such optimization *(Id.).*

Whereas OEB staff focus on the duration of PHT motor outages at Darlington, OAPPA questions whether such outages should be scheduled separately from other planned outages as OPG has proposed. It is OAPPA's contention, supported by LPMA, that seven PHT motor-specific outages at Darlington during the IR term can be rescheduled to coincide with other planned or refurbishment outages to avoid production losses (OAPPA argument, pp. 6-11). Based on its proposed alternate outage schedule, OAPPA submit that the OEB should increase the production forecast for Darlington by no less than 2.95 TWh over the IR term. According to OAPPA, its outage plan would: a) save ratepayers approximately $500M over the IR term; b) pose no safety risk; and, c) align with the Memorandum of Agreement ("MOA") between OPG and its Shareholder. In OPG's view, the OEB should reject OAPPA's proposed increase to the Darlington production forecast for the reasons provided in the following paragraphs.

The methodology that OAPPA uses to develop its alternate outage plan, which OAPPA itself characterizes as “overtly simplified” (Tr. Vol. 15, p. 125), does not adequately account for the risk of premature PHT motor failure. A PHT motor failure results in an unplanned outage and could result in an extended outage depending on availability of spare motors (Ex. L-4.2-1 Staff-41, Attachment 1, p. 4). For example, PHT motor failures resulted in production losses of about 1 TWh in 2015 and 0.4 TWh in 2016 (Tr. Vol. 13, pp. 24-25). OPG seeks to avoid the significant risk of re-occurrence of the forced and unbudgeted planned outages that caused these losses by appropriately scheduling PHT motor-related outages as soon as possible rather than delaying replacement to coincide with other planned outages. The risk of premature motor failure remains high based on OPG’s robust monitoring and current condition assessments and inspections of disassembled old motors that have been replaced and this risk is the number one enterprise-level risk for OPG (Ex. L-5.1-12 OAPPA-6; Tr. Vol. 15, pp. 119-120, 123).

While OPG’s preference would be to carry out all of the motor replacements during planned outages as OAPPA recommends (Tr. Vol. 15, p. 124), OPG cannot simply shift the seven PHT-specific outages at Darlington by several years due to practical constraints, including motor availability. To accelerate motor replacement, OPG decided in May 2016 to purchase four new motors and reduce the number of motors to be refurbished accordingly (Ex. L-4.2-1 Staff-41). However, new motors are not readily available for installation due to their size, complexity and unique engineering requirements (Tr. Vol. 15, pp. 125-126). As OPG’s witness indicated, “these pieces of equipment are huge, complex, and there's not -- like there's not three or four vendors out there that do it. So they're doing it one at a time. So there is a time that they have to take to get the motors done and shipped and tested, and so they don't all -- we can't get them all at once either” (Tr. Vol. 15, p. 125).

Even if it were feasible for OPG to adopt OAPPA’s outage plan, doing so would not save ratepayers approximately $500M as OAPPA contends (OAPPA argument, p. 9). This is because OAPPA’s submission is incorrectly predicated on the assumption that approximately one-half of the $500M is paid to OPG for lost production. OPG is not compensated for lost production (Tr. Tech. Conf. Vol. 2, p. 152). The nuclear payments are 100% variable, meaning that the company’s revenues vary directly with the amount of electricity it produces from the nuclear facilities. Furthermore, the remaining half of OAPPA’s perceived $500M savings that is associated with the cost of replacement energy is not a relevant consideration in OPG's view. Estimating the cost of the production that would replace Darlington's output during a PHT motor-specific outage is a complex analysis that requires information that is beyond the scope of this proceeding and, in any event, is not relevant to establishing OPG's production forecast.

OAPPA's submission that PHT motor failures do not pose a safety risk and that OPG confirmed this position during the proceeding (OAPPA argument, pp. 9-10) is also incorrect. While OPG has noted that the CANDU design includes a number of safety features (e.g. thermo-siphoning) that mitigate certain risks associated with PHT motor failures, the fact remains that risk associated with motor failure persists.

A PHT pump motor failure will result in an automatic reactor trip resulting in a station shutdown. A recognized measure of industry safety practice is minimizing automatic reactor trips as described in OPG's 2016 Benchmarking Report. The "2-year Reactor Trip Rate" is one of the nine metrics that OPG uses to benchmark safety performance and OPG currently operates at best quartile for both Pickering and Darlington on this safety metric (Ex. F2-1-1 Attachment 1). OPG staff are trained to monitor the condition of the PHT pump motors to avoid an automatic station shut-down triggered by PHT motor failure (Tr. Vol. 15, p. 110). As OPG's witness explained during the oral hearing, "So of course we would prefer to do it during a planned outage. We will do so if conditions and component conditions allow, but ultimately we have to plan for a replacement outside of planned outages, and fundamentally this comes down to a safety issue, and we will not impact reactor safety" (Tr. Vol. 15, p. 124).

OAPPA also contends that planning separate PHT motor outages is inconsistent with the MOA between OPG and its Shareholder, which mandates OPG to "plan and operate its generation facilities based on good utility practice recognizing safety, legal, regulatory, environmental and market factors" (OAPPA argument, pp. 10-11). For the reasons noted above, in OPG's view, its proposed outage schedule is fully in accordance with good utility practice and therefore with its MOA mandate. Moreover, in OPG's view it would be irresponsible and contrary to good utility practice to delay these outages and simply hope that the old motors last until the applicable refurbishment or planned outage window in the face of evidence showing a high risk of failure.

Finally, OEB staff question the validity of OPG's production forecast by noting that OPG has not undertaken a comprehensive assessment of its forecasting methodology or engaged an external expert to review it (OEB staff argument, p. 72). In response, OPG observes that the evolution of OPG's production forecasting methodology, as shown over the course of its applications to the OEB, demonstrates that the company has sought to improve and refine its forecasting approach (Tr. Vol.12, pp. 122-125). Furthermore, OPG is unaware of any standard production forecasting methodology used across the nuclear industry and, given the significant differences between CANDU and Pressurized Water Reactor/Boiling Water Reactor technology that is used extensively in the United States (Ex. F2-1-1, p. 4), OPG submits that an outside study would be of little value. In sum, OPG is confident that its methodology produces a robust forecast of the production anticipated during the IR term for both Pickering and Darlington.

In its Decision with Reasons in EB-2007-0905, the OEB stated at page 174 that it believes, "OPG should be fully incented to produce as accurate a forecast of nuclear production as possible and should be at risk if actual output falls short of forecast." OPG's nuclear production forecast is a complete and accurate forecast and should be used to set payment amounts over the IR term.

7.0 OPERATING COSTS

7.1 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?

7.1.1 Introduction

OEB staff and parties' submissions address two aspects of nuclear OM&A, base and outage. OEB staff, supported by LPMA and VECC, recommend a disallowance of $40M per year in base OM&A attributed to claimed excessive labour and overtime costs, and historical under-spending on purchased services.[50] OEB staff, supported by VECC, also propose a

[50] VECC argues in the alternative "If the Board were to go further and simply keep OM&A costs at the level of 2016 actual costs, this would result in $89 million in savings to ratepayers, as the table below indicates." (VECC argument, para. 6.1.3). As VECC fails to establish any evidentiary basis for why the difference between 2016 budget and actual total operating costs, which includes items like tax and depreciation, logically translates into an OM&A disallowance during the IR term, OPG will not respond further to this argument. OPG also wishes to note that VECC's Table 1 has the following errors:

1. Property tax in 2014 should be $13.2M and the total should be $2,806.2M per the Nov 10, 2016 update to Ex. F2-1-1 Table 1; and

disallowance averaging $19.1M per year for outage OM&A based on claims of excessive Darlington Unit 2 outage spending and historical under-spending in outage OM&A. AMPCO recommends that the annual forecasts for other purchased services be reduced by 20% in base OM&A and by 24% in outage OM&A. This results in reductions of $178.5M and $272.3M in base OM&A and outage OM&A, respectively, over the IR term. LPMA proposes an 8% annual disallowance of outage OM&A costs based on alleged historical under–spending, which would result in a $153M reduction over the IR term. SEC recommends an unspecified decrease in the OM&A budgets to account for unnamed efficiency initiatives that OPG should be pursuing. In contrast, the PWU supports no disallowances and submits that the outage budget for Darlington Unit 2 is reasonable (PWU argument, paras. 41, 51).

Parties also propose denying recovery of the costs of the CNSC Fitness for Duty program or at least tracking these amounts in a deferral account.

Below OPG responds to the OEB staff and parties' submissions and shows that recommended disallowances are not justified on the record of this proceeding and therefore should not be accepted by the OEB.

7.1.2 Base OM&A

OEB staff, supported by LPMA and VECC, propose reducing base OM&A by $40M per year. The proposed reduction is tied to two cost areas: $15M per year for labour and overtime costs and $25M per year related to other purchased services costs (OEB staff argument, p. 77-78; LPMA argument p. 14; VECC argument, para. 6.1.1). These reductions are in addition to both the proposed reductions in compensation costs related primarily to pension and benefits costs, and the parties' proposal to double the nuclear stretch factor and extend it to all OM&A. As discussed in Section 7.7 the total OM&A reduction recommended in this Application by OEB staff, is more than 50% higher than the disallowance in EB-2013-0321.

2. Total operating costs (line 16) in 2017 to 2021 are incorrect (although the individual line items above the total are correct). The sums shown for 2017 to 2020 should actually be the sums shown for 2018 to 2021.

Before turning to the specific elements of base OM&A reviewed in parties' submissions, OPG submits that it is the overall base OM&A budget that should be assessed for reasonableness (recognizing that it will be reduced further by the stretch factor), not individual components. This approach to reviewing OM&A spending is appropriate because the various categories of base OM&A can be substituted for one another as Ms. Carmichael explained:

> I would like to state that overall, if you do look at our base OM&A picture, we plan in various categories, but they don't always happen in each of the categories, so labour, overtime, aug staff, purchased service, there's a mix. So sometimes the actual don't always agree with the way it was planned. But from an overall perspective, we have a steady state base OM&A budget. It escalates at 1.24 percent and we're also proposing a stretch factor of .3 on top of that. So we think this is a reasonable projection of cost structure for the base OM&A nuclear group. (Tr. Vol. 14, pp. 8-9).

In this vein, OPG notes that, on average, base OM&A, excluding Pickering Continued Operations spending that is subject to CRVA, has been slightly higher than budget by about $11M per year, over 2010-2016, the seven-year period reviewed by OEB staff in a number of areas in their submission (see e.g., OEB staff argument, pp. 78, 81).[51] Looking at 2016 alone, the overall under-spend between planned and actual spending is about $19M, or less than half OEB staff's $40M proposed annual disallowance (Compare Ex. F2-2-1, Table 2 with Ex. J14.3, Attachment 1). As noted previously, the 2016 difference was primarily caused by greater than anticipated attrition and the lag in hiring (Ex. J15.12, AIC, p. 74), which is being addressed through new hiring processes (Tr. Vol. 16, pp. 151-52; Ex. L-11.4-1 Staff-255(a)).

On this basis OPG respectfully submits that OEB staff's recommended disallowance is excessive and should not be adopted. Moreover, the recommended disallowance for labour and overtime costs overlap, at least in part, with parties recommended disallowances for compensation and benefits (see Section 7.7) as well as with the reductions that would arise from proposed changes to the stretch factor (see Section 12.5).

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[51] This figure is the average of variances for the period 2010-2016 between actual total base OM&A excluding Pickering Continued Operations and budgeted (i.e., OPG proposed) total base OM&A excluding Pickering Continued Operations, before disallowances (for 2010-2012, see EB-2013-0321 Ex. F2-2-2, Table 1; for 2013-2016,see EB-2015-0153 Ex. F2-2-2, Table 1). The only other adjustment made is to remove $196.4M from EB-2010-0008 budgeted value for 2012 in order to normalize with the actual value, on account of organizational changes through Business Transformation (EB-2013-0321 Ex. F2-2-2, p. 4, lines 7-11).

Labour and Overtime

OEB staff support their recommended reduction for labour and overtime costs on the basis that OPG's forecast for Darlington work is too high given that Unit 2 is undergoing refurbishment. OPG provided a comprehensive explanation of why OM&A costs do not generally decline when Darlington units are undergoing refurbishment. To summarize, the majority of costs associated with the operation of Darlington are unchanged by refurbishment as many of the functions that support the operation of all four units continue to be required even while units are on refurbishment outages (Ex. L-6.1-2 AMPCO-92). In addition, OPG has a comprehensive plan to perform non-refurbishment maintenance work on the unit that is offline. This work includes preventative and corrective maintenance work that would normally be done during scheduled outages but will be spread over the refurbishment period to be completed while a unit is on a refurbishment outage (*Id.*).

In the context of why Darlington's total generation cost benchmarking performance will not improve during refurbishment, Ms. Carmichael explained the ongoing work that OPG expects to accomplish on the Darlington units that are undergoing refurbishment and the importance of completing that work as follows:

> MS. CARMICHAEL: [...] leading up to the refurbishment period and during the refurbishment period, we do not expect that Darlington will be at better than third quartile. We have extra costs due to the life extension, so just because we're refurbishing the core of the unit. We are going to be doing a lot of work on the rest of the unit, so those costs are incurred as operating costs. We will be maintaining the equipment, some equipment that in fact we haven't even been able to get to since commissioning, so we're going to be working on that kind of equipment. So all of these things, even though we normalize for lost generation, we know that we're going to be spending more operating costs on Darlington to basically fix -- or preventative main -- do preventative maintenance and corrective maintenance on all the equipment, all the components associated with that unit, so that when the unit comes out of refurb the expectation is that it is a very good performing plant. And if we don't do that work now during the refurbishment period and put that investment into the plant, we will sustain issues coming out of refurb, which we know other utilities have sustained, because it did not put the investment into those equipment components. (Tr. Vol. 14, pp. 23-24).[52]

[52] Additional discussion on this point can be found at Tr. Vol. 14, p. 50.

In OPG's submission, this is a complete answer to why OM&A expenditures at Darlington, do not, and should not be expected to decline during refurbishment. OPG further submits that these expenditures are necessary for ratepayers to receive the full benefits of the investment in refurbishment (Tr. Vol. 14, pp. 24-25).

OEB staff submit that the reduced number of Darlington units operating and the resulting reduction in outages should translate into less overtime, but this submission seems to be confusing outage and base OM&A. While it is correct that outages are a main driver of overtime in general, planned outage overtime costs are reflected in the outage OM&A budget (Ex. F2-4-1, Table 2). The base OM&A budget captures overtime costs related to peak work requirements and maintaining coverage for "key staff positions (e.g., authorized nuclear operators) and provide backup for absent staff so as to maintain minimum staff complement on each shift." (Ex. F2-2-1, p. 4). It is only when overtime is used during forced outages that it is funded through base OM&A (Ex. F2-2-1, p. 2).

As OEB staff counsel noted in cross examination and OPG agreed, base OM&A overtime is generally quite stable over both the historical and forecast periods (Tr. Vol. 13, pp. 87-88). This stability is to be expected since base OM&A overtime is forecast based on a percentage of forecast labour costs (*Id.*). The major exception to this stable trend, as shown in Table 21, line 2 of OEB staff's submission, occurred in 2016 when base overtime was more than 25% higher than the average of the other years shown (OEB staff argument, p. 76). As OPG has established, the increase in 2016 base overtime was driven by the lag in hiring for critical positions (Tr. Vol. 15, pp. 100-101). This further confirms that outages are not the major driver of base OM&A overtime expenditures.

AMPCO recommends that OPG needs to focus on resource planning based on what it characterizes as an excessive use of overtime (AMPCO argument, para. 218). Elsewhere in its submissions, AMPCO criticizes OPG and recommends disallowances based on under-spending of its other purchased services budget (AMPCO argument, para. 212). As explained above, overtime and other purchased services often are substitutes. OPG uses them as flexible resources to complete necessary work. While OPG budgets in specific categories, its actual use of these resources depends on their cost and availability when they are needed (Tr. Vol. 14, pp. 7-9).

OEB staff also question whether OPG has properly accounted for the labour costs between the DRP and Darlington Operations (OEB staff argument, p. 76-77). As OPG testified, approximately 100 staff have been transferred from Darlington to work on the DRP (Tr. Vol. 13, p. 77). These staff have been budgeted to the DRP and their costs capitalized (Tr. Vol. 13, p. 79). On the rare occasions that staff make temporary moves from Darlington to DRP, their costs are charged to DRP (Tr. Tech Conf. Vol. 1, p. 36). While actual staff usage between Darlington and the DRP may differ slightly from plan for any number of reasons, there is no systematic double counting of Darlington costs as Ms. Carmichael testified:

> MS. CARMICHAEL: 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. (Tr. Vol. 13, p. 80)[53]

OEB staff argue that the potential to move staff from Darlington to the DRP on occasion provides further support for its view that Darlington labour costs are too high (OEB staff argument, p. 77). This is incorrect. If a situation requires that certain personnel be temporarily assigned to the DRP, OPG will backfill at Darlington with overtime, augmented staff or contracted labour as is discussed further below. But in any event, the staff working on the DRP will be charged to the DRP and staff or other resources working at Darlington will be charged to Darlington.

OEB staff calculate their recommended disallowance for labour and overtime based on a percentage of the difference between 2016 actual and 2017 forecast cost (OEB staff argument, p. 76-77). In OPG's submission, the one year difference on selective components of OM&A is not an appropriate basis for comparison even if OEB staff do not recommend disallowing the entire difference. Instead the OEB should examine OPG's overall base OM&A budget and

[53] OEB staff requests that OPG explain this due diligence process and provide supporting documentation and cost reconciliation in future applications (OEB staff argument, p. 77). OPG responds that if this issue relates to material costs in future applications, OPG will provide the information necessary to support and explain the requested costs.

make a judgment on its reasonableness recognizing that it will be reduced further by the stretch factor.

Other Purchased Services

OEB staff recommend a $25M annual disallowance based on their historical comparison between budgeted and actual amounts for other purchased services costs (OEB staff argument, p. 78). AMPCO advocates a 20% base OM&A disallowance for other purchased services, which totals $178.5M over the IR term (AMPCO argument, para. 204).[54] These recommended disallowances exemplify a pattern where costs that are interrelated are looked at in isolation. As mentioned above, augmented staff, overtime and other purchased services are all various methods of supplementing OPG's labour force to accomplish necessary work. Their use is optimized based on cost, availability, timing and the limits of the collective agreements. If all of these items are looked at together, the pattern of consistent and significant under-spending, as claimed by OEB staff and AMPCO, changes.

Chart 7.1 reproduces the information shown in OEB staff Table 22, but adds the figures for overtime and augmented staff. Chart 7.1 shows that from 2010-2016 the total difference between planned and actual spending over this seven-year period is $26.8M. The average annual difference over this period is $3.8M, compared to OEB staff's recommended annual disallowance of $25M and AMPCO's recommended annual disallowance of $35.7M. This information demonstrates that OEB staff's recommended disallowance is based on a selective review of a single cost from a group of interrelated costs and therefore should not be approved (Tr. Vol. 15, p. 96).

[54] OPG notes that in the Table on the top of page 43 of AMPCO's submissions, the total column is wrong. The correct numbers can be found in OEB staff's Table 22.

Chart 7.1
Base OM&A Categories Plan vs. Actual

BASE OM&A (Overtime; Augmented Staff and Other Purchase Services)								
$Millions	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**Total**
Plan	146.5	138.7	133.6	157.2	178.2	179.7	215.2	1149.1
Actual	155.9	152.3	146.5	151.7	149.1	167.3	199.5	1122.3
Variance	9.4	13.6	12.9	-5.5	-29.1	-12.4	-15.7	-26.8
% Variance/Plan	6.4%	9.8%	9.7%	-3.5%	-16.3%	-6.9%	-7.3%	-2.3%
Source: Ex F2-2-1 Table 2, EB-2010-0008, EB-2013-0321, EB-2016-0152;J14.3 Attachment 1								

7.1.3 Outage OM&A

OEB staff's and LPMA's submissions recommend that OPG's Outage OM&A be reduced by 5% and 8% per year, respectively. The OEB staff recommendation equals an average of $19.1M per year or more than $95M over the IR term (OEB staff argument, p. 81). LPMA's reduction would average $30.5M per year and total $152.6M (LPMA argument, p. 14). AMPCO recommends that outage OM&A be reduced by $272.3M over the IR term or an average of $54.5M per year (AMPCO argument, paras. 204, 214).

None of the parties recommending disallowances acknowledges that $233.6M of the forecast IR term outage OM&A expenditures are for enabling costs related to PEO (Ex. L-6.5-1 Staff-118). These costs are tracked through the CRVA and are subject to refund if under-spent (AIC p. 23). To avoid double counting, these parties should have excluded outage OM&A spending for Extended Operations from their recommended reductions, but none did.

OEB staff offer two bases for their recommendation: 1) OPG is spending too much on Darlington Unit 2 outages, and 2) in recent years OPG's outage OM&A spending has been less than forecast. The LPMA and AMPCO recommendations are also based on claimed under-spending. On the first point, the record is clear that the requested costs are fully justified as OPG is planning to carry out the work of two planned outages during the refurbishment window and plans to undertake extensive renewal of Unit 2 beyond the DRP activities so that the unit will perform reliably once it returns to service. On the second point, while there has been some under-spending in recent years, this is largely attributable to shifts in outage and related scope changes. Both these points are fully explained in the paragraphs that follow.

On Unit 2, OEB staff's first point is that the spending over the 2017-2019 period while the unit is undergoing refurbishment is higher at $124M than the typical spending level for a Darlington outage of $80-$100M (OEB staff argument, p. 80). However, as OPG stated, the work to be accomplished during 2017-2019 replaces work that would have been done during the two planned outages that would have begun in late 2016 and in 2019, absent refurbishment (Tr. Vol. 13, pp. 72-74). Moreover, as noted above, during refurbishment, OPG will be performing extensive preventive and corrective maintenance activities to ensure that when Unit 2 returns to service it is well positioned for 30 years of additional reliable operation (Tr. Vol. 14, pp. 23-24). Thus, the work that will be performed on Unit 2 during refurbishment is not the same as a typical outage.

As noted in OPG's evidence, the scope of the DRP was revised based on the recommendations of the Blue Ribbon Panel. This exercise allowed OPG to establish a final DRP scope, but it did not eliminate the need for necessary tasks that were not included in the final DRP scope. This work is now being performed by the station (Ex. D2-2-5, pp. 3-4; Ex. F2-4-2, p. 1, lines 18-24).

OEB staff offers up the fact that the $6.1M in outage OM&A for Unit 1 that OPG forecasts for 2021 is likely appropriate for the extended outage work in an effort to support its view that Unit 2 outage OM&A is too high (OEB staff argument, p. 80). A more extensive examination of Unit 1 outage OM&A spending, however, supports the opposite conclusion. Unit 1 is forecast to undergo an outage in 2020 costing $128.2M before its planned refurbishment in late 2021 (Ex. L-6.1-20 VECC-20; Tr. Vol. 13, p. 69-70). This cost is in line with the cost of the Unit 1 outage in 2017 (Ex. L-6.1-20 VECC-20).

With regard to recent under-spending of outage OM&A, OPG has provided variance explanations that detail the causes of material spending shifts in recent years (Ex. F2-4-2, pp. 3-6). Typically, under-spending occurs when outages are shifted from one year to the next because outages must occur on specific cycles approved by the CNSC and resource constraints prevent the advancement of outage work. This can result in changes in outage scope (Ex. F2-4-1, pp. 2-5).

7.1.4 Fitness for Duty Spending

OPG's N1 Impact Statement included $41M over the IR term to implement the CNSC's expected Fitness for Duty program (Ex. N1-1-1, p. 4). OPG anticipates that the CNSC will publish its formal Regulatory Document on Fitness for Duty related to employee drug, alcohol, psychological and physical testing in 2017 (Ex. N1-1-1, p. 20).

SEC, supported by LPMA, makes three points as to why the OEB should deny OPG's request or, place the requested amounts in a variance account: 1) the amounts are not material; 2) the requested funds should have been included in the Application and 3) the CNSC program may never be implemented (SEC argument, paras. 7.1.5 to 7.1.9; LPMA argument, pp. 14-15). While the PWU and SEP do not support approving Fitness for Duty costs, they do support creation of a deferral account to record these costs if OPG incurs them during the IR term (PWU argument, paras. 43-44; SEP argument, p. 7), OPG responds to these submissions below.

OPG's evidence shows that $40M of the $41M request will be spent over three years 2019, 2020, and 2021 and that in each of those years the forecast expenditures exceed the $10M materiality threshold (Ex. N1-1-1, p. 21). On this basis, OPG submits that the requested amounts are material and SEC is in error when it states "for most years in the test period, the amount is not material using OPG's own materiality threshold." (SEC argument, para. 7.1.6).

SEC is similarly incorrect when it states that nothing has changed regarding the CNSC's Fitness for Duty programs since the time OPG filed its Application (SEC argument para. 7.1.6). OPG was asked about this during the hearing and responded that it was not until late 2016 that discussions with the CNSC produced sufficient definition of the anticipated coverage and extent of the testing requirements to enable OPG to estimate the program's cost (Tr. Vol. 13, pp. 109-110).

With regard to the possibility that the CNSC program will not be implemented, OPG submits that its understanding is that the CNSC intends to implement drug and alcohol testing as a licence condition and that the lack of such testing in Canada has been identified as a gap by the International Atomic Energy Agency (Tr. Vol. 13, p.113-114). Recognizing that it is possible the program could be delayed and the forecast costs may be different than expected over the

IR term, OPG would support the creation of a deferral account to capture the actual costs as proposed by SEC, LPMA, SEP and the PWU (Tr. Vol. 20, pp. 163-164).

7.2 Issue 6.2

Oral Hearing: Is the nuclear benchmarking methodology reasonable? Are the benchmarking results and targets flowing from OPG's nuclear benchmarking reasonable?

No specific disallowances were proposed based on OEB staff's or intervenors' review of various aspects of OPG's nuclear benchmarking methodology, results and targets. Rather, nuclear benchmarking results were used to inform the parties' recommendations on other aspects of OPG's Application, including proposed adjustments to the nuclear stretch factor (see Issue 11.3, Section 12.6), OPG's OM&A forecast (see Issue 6.1, Section 7.1), and compensation (Issue 6.6, Section 7.7).

CCC submits that benchmarking results should be considered by the OEB when determining OPG's payment amounts (CCC argument, p. 22). OPG agrees. While benchmarking provides insight into relative cost and performance, it is not a precise tool, as noted by ScottMadden in respect of its Phase 1 Benchmarking Report:

> In our opinion, the comparisons provided in this report present a fair and balanced view of OPG operating and financial performance compared to other operators in the nuclear generation industry. However, it would be inappropriate to generalize regarding OPG's absolute performance based solely upon comparisons to industry averages. Differences in design technology, the number of reactors on site, the geographic size of the site, reactor age, operational condition and other factors all influence OPG's operational and financial performance. Benchmark data can be useful for highlighting performance gaps relative to other nuclear generation operators but prescriptive conclusions regarding OPG's ability to narrow such performance gaps will require further analysis. (EB-2010-0008, Ex. F5-1-1, p. 2).

OEB staff's and intervenors' arguments separately discuss the benchmarking methodologies developed by ScottMadden Management Consultants ("ScottMadden") and by Goodnight Consulting ("Goodnight"). OPG's Reply Argument is similarly organized.

Nuclear Benchmarking (ScottMadden)

OEB staff and a number of intervenors (i.e., AMPCO, CME, CCC, EP, LPMA, SEC and VECC) submit various claims that OPG's nuclear benchmarking results are poor; that OPG has not exhibited continuous improvement; and that OPG's approach to normalizing total generation cost per MWh ("TGC/MWh") during DRP was not ScottMadden's "preferred" normalization approach. In OPG's view, the evidence is that OPG has performed well in the context of each nuclear station's lifecycle stage; the benchmarking results demonstrate continuous improvement in a number of areas; and, ScottMadden has in fact validated OPG's approach to normalizing TGC/MWh.

OEB staff recognize that it is "probably not reasonable to expect OPG to achieve first or second quartile overall results" (OEB staff argument, p. 88). Despite this recognition, OEB staff attempt to portray OPG's nuclear benchmarking results as excessively poor by focusing on the results at the operator level, which they believe to be most relevant (OEB staff argument, p. 84).[55] This position is supported by a number of intervenors and is used to propose changes to OPG's TGC/MWh benchmark-based stretch factor proposal, which OPG disputes (see Issue 11.3, Section 12.5 for further discussion).

As OPG's witness explained during the oral hearing, it is more appropriate to look at OPG's two nuclear facilities individually given that they are at different stages of their lifecycle, have different sized units and reflect different generations of CANDU technology (Tr. Vol. 13, pp. 13-14). As noted in the 2016 Nuclear Benchmarking Report, "[o]perator level summary results are the average (mean) of the results across all plants managed by the given operator. These comparisons provide additional context, but the detailed data in the previous sections [of the report] provide a more complete picture of plant by plant performance" (Ex. L-6.2-15 SEC-63 Attachment 1, p. 83). Consequently, Pickering's TGC/MWh challenges (described below) are amplified and give the appearance of poor performance in the major operator level summary results, as Pickering's results outweigh Darlington's historically strong performance (also described below and under Issue 11.3 (Section 12.5)).

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[55] OEB staff incorrectly note that OPG has never ranked higher than 10th out of 13 on TGC/MWh at the operator level (OEB staff argument, p. 88). As shown in Ex. L-6.2-15 SEC-63, Attachment 1, p. 87, OPG ranked 8th out of 13 in 2013.

The results at the station level are shown in OEB staff's nuclear benchmarking summary (OEB staff argument, p. 83). This summary shows results from 2008 to 2015 for Darlington and Pickering for the three key benchmarking metrics (TGC/MWh, Nuclear Performance Index ("NPI") and Unit Capability Factor ("UCF")). For reasons explained below, benchmarking performance at the two stations is markedly different despite Pickering and Darlington being subject to the same OPG governance and oversight controls, human resources policies, staff training requirements, and regulatory frameworks.

Pickering's benchmarking results are challenged by its smaller unit size, first generation CANDU technology and low capability factor attributable to the extensive planned outage program that is required for PEO (Ex. F2-1-1, p. 3; Tr. Vol. 13, p. 15, lines 14-27). CME's characterization of Pickering's benchmarking results as "abysmal" (CME argument para. 230) and EP's questioning "why the plant should continue to remain in operation" if it cannot achieve "at least the median level of performance" (EP argument, para. 6.10) appear to discount these challenges. Pickering's small unit size (540 MW) relative to other nuclear facilities (e.g., Darlington has a 934 MW unit size) is a particular constraint that impacts benchmarking performance (Ex. L-6.2-15 SEC-63 Attachment 3, p. 77). OEB staff recognize various practical challenges at Pickering and note that "it is not realistic to expect that [Pickering] will be a top performer" (OEB staff argument, p. 84).

Despite these challenges, Pickering managed to achieve its best performance to-date on the NPI and UCF metrics in 2015 (OEB staff argument, p. 83), while maintaining stable TGC/MWh even as peers in the top quartile and median experienced significant growth (as discussed further below). This improvement was driven in part by Pickering's improved FLR performance. As noted in the 2016 Nuclear Benchmarking Report, "Pickering's [rolling two-year average] FLR performance over the 5 year review period, has been improving. The equipment reliability improvements at Pickering have been the main drivers for the favourable improvement in FLR performance. FLR performance appreciably improved in 2015 by a reduction in station FLR (6.85) from 2014 FLR (10.08)" (Ex. L-6.2-15 SEC-63 Attachment 3, p. 53).

Darlington has benchmarked very well historically (OEB staff argument, p. 83). In 2015, Darlington's benchmarking results were impacted by several factors. The 2015 VBO at Darlington and forced losses and unbudgeted planned outages associated with PHT pump motors were key contributors to lower production, which OEB staff, CME and EP acknowledge (OEB staff argument, p. 84, CME argument, paras. 393-395, EP argument, paras. 6.7-6.9)[56]. While the parties recognize these factors, they downplay their significance by arguing that all nuclear facilities have periodic outages over their lifecycles and that OPG's benchmarking comparators are faced with similar challenges (*Id.*). The parties may try to make these unique events seem routine, but the fact remains that these factors contributed significantly to Darlington's 2015 benchmarking performance (AIC, p. 81; for further discussion see Issues 11.3 and 11.4 (Section 12.5)).

In particular, the 2015 VBO at Darlington required the shutdown of all four units, which was one of the main factors contributing to 234 more outage days in 2015 than in 2014 and also increased outage OM&A costs in 2015 (Ex. L-6.2-15 SEC-63, Attachment 3, pp. 71-72). OPG notes that the VBO in 2015 was longer than the VBO in 2009 because the 2015 outage combined a Station Containment Outage with the VBO and included critical path work related to emergency service water piping and emergency coolant injection valve replacement (EB-2013-0321 Decision with Reasons, p. 39), so its impact on generation was necessarily greater. OEB staff's view that the 2015 VBO should have had a minor impact on Darlington's benchmarking performance based on the 2009 VBO is therefore incorrect (OEB staff argument, p. 84). Furthermore, since VBOs are unique to CANDU nuclear technology, the performance of OPG's benchmarking comparators, which use Pressurized Water Reactor ("PWR") or Boiling Water Reactor ("BWR") technology (all comparators except Bruce Power), does not reflect VBO-related outages and costs (Ex. L-6.2-15 SEC-63, Attachment 3, p. 103, Tr. Vol. 13, p. 26).

AMPCO submits that because OPG was aware of operational risks at Darlington associated with PHT motor failures, PHT pump seals as well as the 2015 VBO, that the decline in benchmarking performance in 2015 must be attributable to "poor performance in effectively managing these risks" (AMPCO argument, paras. 188-189). AMPCO's unsubstantiated assertion is contrary to the evidence, which shows that OPG took steps to prudently manage those risks. For example, OPG accelerated the replacement of degraded PHT motors to mitigate the risk of premature PHT motor failure (Ex. L-4.2-1 Staff-41, see Issue 5.1 for further

[56] SEC also acknowledges the VBO impact only (SEC argument, para. 7.2.7).

details). OM&A project # 80071 is underway to address PHT pump seal deficiencies (Ex. F2-3-3 Table 2b) and PHT pump seals did not result in any production losses at Darlington in 2015 (Ex. L-6.1-15 SEC-59, p. 4). As for the 2015 VBO at Darlington, it was successfully executed in accordance with CNSC requirements (Tr. Vol. 13, p. 95). Thus, contrary to AMPCO's submissions, OPG effectively managed the emerging PHT motor failure, PHT pump seal and VBO risks to avoid further decline in benchmarking performance at Darlington in 2015.

OEB staff, EP and SEC also do not acknowledge the increased capital investment required to achieve strong reliability and operating performance at Darlington post-DRP as a cause of Darlington's decline in benchmarking performance in 2015. Although Darlington's nuclear capital expenditures per megawatt continues to benchmark in the top quartile (Ex. L-6.2-15 SEC-63, Attachment 3, pp. 81-83), the necessary increase in capital investment is another key driver of Darlington's 2015 benchmarking performance (Tr. Vol. 13, p. 24, line 26 - p. 25, line 17, p. 28, lines 10-20). Darlington's capital costs continued to increase in 2015 due to aging plant equipment, refurbishment support and regulatory requirements to prepare Darlington for extended life after refurbishment (Ex. L-6.2-15 SEC-63 Attachment 3, pp. 71-72, Tr. Vol. 13, p. 30, lines 10-18).

Despite the challenges discussed above, OPG has exhibited continuous improvement in a number of areas, contrary to the view expressed by OEB staff and various intervenors (e.g., OEB staff argument, p. 85). The 2016 Benchmarking Report shows that Pickering's TGC/MWh improved slightly in 2015. Since 2010, Pickering has off-set inflation and maintained a stable TGC/MWh, thereby improving its relative performance as industry costs have escalated, which is shown by the increase in top quartile and median TGC/MWh values (Ex. L-6.2-15 SEC-63, Attachment 3, p. 70). During the 2010-2015 period, Pickering's TGC/MWh was relatively flat with an annual compound growth rate of 0.5%, whereas the industry top quartile and median experienced compound annual growth rates of 3.4% and 2.1% per year, respectively, over the same period (Ex. L-6.2-15 SEC-63, Attachment 3, p. 71). Darlington has also exhibited continuous improvement and has been recognized by the World Association of Nuclear Operators ("WANO") as being among the best performing nuclear plants in the world (Tr. Vol. 13, p. 28; Tr. Vol. 15, p. 150). Between 2010-2014, Darlington showed improvement in the key benchmarking metrics (OEB staff argument, p. 83).

As OPG noted in AIC (p. 84), OPG sets business planning targets that are designed to close performance gaps and significantly drive OPG's Nuclear Operations performance. OPG establishes operational, financial, generation and staff targets set by reference to historical performance, targets established in the prior years, and updated benchmarking results (Ex. F2-1-1, p. 14). OPG's projected targets for the 2017-2021 period are shown at Chart 4 and Chart 5 of Ex. F2-1-1, pp. 15, 17. These targets are challenging, but achievable. They were set on the basis that Darlington and Pickering will require significant investment and operational excellence to achieve the desired outcome of low cost, safe and reliable generation (Ex. F2-1-1, p. 14). SEC submits that OPG has not undertaken sufficient productivity initiatives as part of its Custom IR plan (SEC argument, para. 5.4.1). For the reasons provided in Section 5.4 under the sub-heading "Insufficient Productivity", OPG submits that SEC's assertion does not properly consider how OPG's initiatives are intended to close performance gaps and contribute to its goal of continuous improvement. In SEP's submission, various OPG initiatives currently underway will improve the efficiency and effectiveness of its nuclear operations during the IR term to the advantage of the ratepayer (SEP argument, pp. 8-9).

SEC and AMPCO submit that OPG's targets for the key benchmarking metrics do not show continuous improvement going forward (AMPCO argument, paras. 195-197; SEC argument, paras. 7.2.8-7.2.9, 7.2.12). These submissions focus solely on the metrics at each station that decline and ignore any improvement. For example, SEC mentions the decline in the Darlington NPI, but ignores the improvement in the Pickering NPI shown on the same chart. Both parties omit any mention of factors, such as refurbishment and the outages required for PEO that drive the forecast benchmarking targets. For the reasons discussed above, OPG submits that its goal of continuous improvement needs to be considered in the context of these operational realities.

SEC's assertion that "OPG almost never meets its own annual nuclear operational targets", particularly with respect to 2016 (SEC argument, para. 7.2.11) is incorrect. Using SEC's own table of forecast vs. actual data (SEC argument, para. 7.2.11), it is clear that OPG improved significantly in 2016, having outperformed the forecast in that year for the majority of the metrics shown. SEC's table also reflects the fact that OPG sets very challenging targets for itself, and that annual targets have gotten more stringent over time in several areas (e.g. FLR). AMPCO's submission that Darlington's collective radiation exposure target for 2017 is another sign that OPG does not demonstrate continuous improvement is also unwarranted. OPG notes that while collective radiation exposure at Darlington is expected to temporarily increase in 2017, it is expected to decline in 2018 and 2019. The 2017 increase is largely due to the scope of the Unit 1 outage that includes a single fuel channel replacement program, which is required by the CNSC every four years (Ex. L-6.2-1 Staff-100).

OPG has derived both normalized and non-normalized TGC/MWh targets for Darlington during DRP (Ex. L-6.2-1 Staff-101(a) and (b); Ex. JT2.09). The main thrust of OPG's normalization approach is to add lost production associated with refurbishment back to the denominator in TGC/MWh. OPG is proposing to continue reporting and setting internal performance targets for TGC/MWh on a non-normalized basis (Ex. F2-1-1, p. 16; Tr. Vol. 13, pp. 46-47). However, OPG believes that normalization enables more representative benchmarking against industry peers, and is a necessary tool to understand the drivers of changes in TGC/MWh during DRP.

Without normalization, the net impact will be to temporarily skew this metric higher than would otherwise be the case. This is because while there is a decline in production there is not a corresponding decline in costs (Ex. F2-1-1, p. 16). Support costs and station costs are largely fixed, as discussed in Section 7.1.2 (Ex. L-6.1-2 AMPCO-92; Ex. L-6.2-1 Staff-101, Attachment 1, p. 6).

OEB staff, EP and SEC question OPG's view that ScottMadden accepted OPG's normalization approach (OEB staff argument, p. 86; EP argument, para. 6.16; SEC argument, paras. 7.2.14-7.2.17). The parties submit that OPG's approach was not ScottMadden's "preferred" normalization approach. OEB staff believe that it calls into question OPG's use of normalization and its appropriateness for setting targets over the IR term. Similarly, SEC contends that OPG should be required to maintain and benchmark non-normalized TGC/MWh during the IR term. For the reasons provided above, OPG intends to continue to set TGC/MWh targets on a non-normalized basis and submits that benchmarking TGC/MWh on a normalized basis will assist both OPG and the OEB in assessing OPG's performance during DRP.

ScottMadden's report concluded that OPG's normalization approach was "unique but logical, reasonable, and easy to understand" (Ex. L-6.2-1 Staff-101, Attachment 1, p. 3). Despite this conclusion, OEB staff, EP and SEC appear to believe that OPG's approach was not accepted by ScottMadden because ScottMadden observed that other normalization techniques have also been used in other circumstances. OPG submits that the parties' suppositions are incorrect – nowhere in their report does ScottMadden state or imply a preferred approach to normalization. Rather, ScottMadden reviewed OPG's approach as well as other alternative approaches and determined that OPG's approach was reasonable.

Furthermore, ScottMadden noted that "Refurb is a unique "mega-project," and the experience and perspective of other industry professionals, while useful to consider, cannot provide established practice for normalizing cost metrics during this unique project." (Ex. L-6.2-1 Staff-101 Attachment 1, p. 3). Therefore, while other normalization techniques have been used in other circumstances, OPG submits that those experiences do not provide appropriate guidance in the context of the DRP. ScottMadden validated OPG's approach to normalizing TGC/MWh during the DRP period as appropriate. On this basis, OPG respectfully submits that the OEB should accept it.

Nuclear Staffing Study (Goodnight)

OEB staff submit that OPG is overstaffed during the IR term (OEB staff argument, pp. 90-91) while SEC indicates that OPG's level of staffing is still a concern (SEC argument, para. 1.3.10). These submissions are at odds with the evidence that demonstrates OPG's staffing levels are appropriate and are expected to be below the Goodnight benchmark despite plans to replace staff in critical roles (Tr. Vol. 13, p. 50, lines 14-21).

OEB staff's claim that OPG is overstaffed appears to be driven by the fact that OPG's Nuclear Operations staff forecast exceeds 6,200 FTEs in 2017-2019. OEB staff appear to have selected the 6,200 FTE figure, which covers only nuclear operations staff, based on its arbitrary conception that the 2014 staffing level is the appropriate level for steady state operation (OEB staff argument, p 90). OEB staff provide no evidentiary support for this conclusion and OPG respectfully submits that the record contains none.

Below OPG discusses why OEB staff's proposed 6,200 FTE cap is inappropriate, but it is worth noting at the outset that OEB staff's own data show that when OPG's forecast nuclear operations FTEs are averaged over the IR term, the resulting figure is 6,144 FTEs (OEB staff argument, p. 92). While OEB staff offer their proposed 6,200 FTE cap as support for recommended disallowances to base and outage OM&A (discussed in Section 7.1), the fact is that over the IR term, consistent use of the 6,200 FTE cap would support increasing, not reducing, OM&A.

OPG submits that the relevant benchmark is the one that was established by Goodnight, the nuclear staffing benchmarking expert. OEB staff appear to have disregarded that OPG has determined, using the same methodology as Goodnight, that its 2016 staffing level was below the 2014 Goodnight staffing benchmark (Ex. L-6.2-19 SEP-003(a)) and that OPG staffing is expected to continue to remain at or below the 2014 Goodnight benchmark over the IR term (Ex. L-6.2-19 SEP-003(b)). In fact, after Nuclear Operations FTEs temporarily increase in 2017 to address critical skills shortages (described further below), they are expected to decline throughout the IR term, ending at 5,815.1 FTEs in 2021 (Ex. J14.6).

The view advanced by OEB staff (OEB staff argument, p. 90-91) and SEC (SEC argument, para. 7.2.19(c)) that OPG's hiring of staff in critical operations, maintenance, engineering and technical roles in light of attrition would put OPG above the Goodnight staffing benchmark during the IR term, is inaccurate for the following reason.

The planned increase in FTEs in 2017 reflects completion of hiring to the level required to sustain Nuclear Operations, undertake Extended Operations at Pickering and increase staffing for the DRP. This is because in 2015 and 2016 actual FTEs were below budgeted FTEs primarily due to higher than planned attrition and delays in hiring Nuclear Operations regular staff (Ex. F2-1-1, p. 13; Tr. Vol. 13, p. 49, lines 10-14). The planned hiring in 2017 would restore staffing to a sustainable level, but would not move OPG above benchmark (Ex. F2-1-1, p. 13; Tr. Vol. 13, p. 50, lines 14-21). As OPG explained in Ex. L-6.2-19 SEP-003(b), "after taking the anticipated operating changes into consideration, the resulting benchmarked OPG FTEs during 2017-2021 are expected to continue to remain at or below the 2014 Goodnight benchmark".

Similarly, OEB staff's assertion that OPG's Nuclear Operations staffing forecast does not "demonstrate the sustainability of the Business Transformation Initiative" (OEB staff argument, p. 90) is also contrary to the evidence. OEB's staff's own table shows that at their highest point in 2017, total Nuclear Operations FTEs, including allocated corporate support FTEs, are about

800 FTEs lower than in 2011 (OEB staff argument, p. 92).[57] By 2021, the forecast number for total Nuclear Operations FTEs is almost 1,400 FTEs lower than in 2011.

As a result, the temporary increase in FTEs in Nuclear Operations staff in 2017 does not undo OPG's multi-year effort to achieve Business Transformation targets through attrition. Rather, Nuclear Operations staffing trends downward during the IR term reflecting continuous monitoring and controls as well as development and implementation of initiatives to streamline processes and identify efficiencies to accommodate expected staff attrition (Ex. F2-1-1, p. 13; Ex. J14.6).

In OPG's view, OEB staff's submission that OPG should file FTEs associated with other purchased services in future proceedings (OEB staff argument, p. 91) should not be adopted by the OEB. OPG does not generally track other purchased services-related contractor FTEs and in many cases has no ability to determine the FTEs associated with other purchased services (Tr. Tech Conf. Vol. 2, pp. 186-188; Tr. Vol. 16, p. 143). OEB staff's use of base OM&A other purchased services costs as a proxy for contractor FTEs (OEB staff argument, p. 92) is inappropriate and, from OPG's perspective, misses the point. It is inappropriate because dollars are not a direct substitute for staff time and because OPG's goal should not be to minimize other purchased services FTEs. Rather, OPG's goal should be to minimize total OM&A costs by optimizing the use of other purchased services and other resources. Since other purchased services costs are already filed as part of OPG's applications, requiring OPG to also estimate contractor FTEs would be of limited value. OPG submits that another reason why FTEs are not a good measure of the reasonableness of the other purchased services cost forecast is that there is a non-labour component to other purchased services, which could skew the data (Tr. Vol. 16, pp. 144-146).

SEC's submission expresses doubt as to whether OPG eliminated the gap between the company's nuclear staffing level and the Goodnight benchmark (SEC argument, para. 7.2.18). SEP concurs with OPG that this gap has been eliminated and supports OPG's contention that

[57] OPG notes that these reductions helped allow OPG to decrease its regular headcount company-wide by nearly 2,700 positions from the beginning of 2011 to the end of 2015 (Ex. F4-3-1, p. 5).

it will continue to benchmark favourably through the IR term (SEP argument, pp. 7-8). In OPG's view, SEC's submission is incorrect for the reasons provided in the following paragraphs.

OEB staff's SEC's and VECC's questioning about the nuclear personnel excluded from Goodnight benchmarking (OEB staff argument, pp. 89-90; SEC argument, para. 7.2.19(a); VECC argument, para. 6.2.8) should not obscure the fact that such exclusions are necessary to compare OPG to peers on an "apples to apples" basis, per Goodnight's methodology. Assertions by SEC and VECC that these exclusions lead to results that may not be reflective of a) "the actual ideal benchmark" (SEC argument para. 7.2.19(a)), or b) "what OPG's activities will ultimately cost ratepayers" (VECC argument, para. 6.2.8) are without merit. OPG respectfully submits that the intervenors' views are unrealistic. As explained below, benchmarking will never match each and every position. Moreover, the view expressed by SEC and VECC are directly opposed to the OEB's finding in EB-2013-0321 that "the Goodnight nuclear staffing analysis was informative" (Decision with Reasons, p. 95).

In the oral hearing, OEB staff sought to clarify the summary of OPG nuclear personnel not benchmarked in the 2014 Goodnight study (Ex. F2-1-1 Attachment 2, p. 14). In Ex. J13.4, OPG explained that the types of exclusions were consistent with previous Goodnight benchmarking studies and that the summary of non-benchmarked OPG personnel was mislabeled in the 2014 Goodnight study.[58] As requested by OEB staff (OEB staff argument, p. 89), OPG confirms that Goodnight did not assist OPG with preparing the response to that undertaking because OPG had all the data necessary to undertake the reconciliation in the 2014 Goodnight study as well as previous Goodnight benchmarking studies and was confident in the accuracy of its response.

SEC's submission that the industry benchmark level may have gone down since the Goodnight report in 2014 is contrary to the evidence. OPG's view, supported by SEP (SEP argument, p. 8), is that it is likely that industry benchmark levels have increased since 2014 for various

[58] In particular, indirect corporate staff (e.g., treasury, tax, etc.) and security staff were incorrectly shown on p. 14 of the Goodnight report (Ex. F2-1-1) under the heading Other Exclusions, which represents Nuclear FTEs that could not be benchmarked. In actuality, these positions were appropriately omitted from the benchmarking either because they are not dedicated to the nuclear business or because the nature of the work they undertake does not permit benchmarking (i.e., security personnel) as is fully explained in Ex. J13.4.

reasons, including regulatory factors such as increased security needs, cyber security, and Fukushima-related requirements (Tr. Vol. 13, p. 55).

More generally, OPG wishes to comment on what appears to be OEB staff's inappropriate expectation for benchmarking here and elsewhere in their submissions. As the OEB has recognized, benchmarking necessarily provides high level directional guidance; it is not prescriptive (EB-2013-0321 Decision with Reasons, p. 80). Simply put, there is no other company that has exactly the same technology, operating environment, organization, regulatory requirements, collective agreements and workforce demographics as OPG – there is no perfect match. Thus, benchmarking will always compare only a subset of OPG's employees. This is sufficient to provide useful directional information, and OPG has used it as such, but it cannot produce a formula by which OPG or the OEB can determine exact staffing levels (Tr. Vol. 17, p. 30).

Finally, OPG wishes to address VECC's submission that OPG "seems to be missing…a tangible link between benchmarking results and rates, allowable returns, or prices to be paid to OPG. Without that connection, the benchmarking analysis provides only limited value in incentivizing further efficiencies and lowering the costs of the utility for ratepayers." (VECC argument, para. 6.2.9). OPG respectfully submits that its proposed benchmark-based stretch factor (discussed further under Issues 11.3 and 11.4 (Section 12.5) directly establishes that tangible link between OPG's benchmarking and its payment amounts that VECC believes is missing. Consequently, VECC's request that the OEB direct OPG to "undertake a study of how best to link benchmarking results to future payment calculations" (VECC argument, para. 6.2.10) is unnecessary. The two are already fully connected.

7.3 Issue 6.3

Secondary: Is the forecast of nuclear fuel costs appropriate?

This issue was partially settled as part of the approved Settlement Agreement (Ex. O-1-1, pp. 9-10; Tr. Vol. 9, p.1). As described at Ex. O-1-1, p. 9, the Parties have agreed to a 2% downward adjustment to the nuclear fuel bundle unit cost forecast in each year of the IR term relative to the forecast in the Application at Ex. F2-5-1, Table 1, line 4, resulting in fuel bundle unit costs as follows: $4.18/MWh (2017), $4.14/MWh (2018), $4.07/MWh (2019), $4.39/MWh (2020) and $4.19/MWh (2021).

The unsettled aspects of this issue are:

- The impact of the approved production forecast on annual nuclear fuel bundle cost;
- All components of used nuclear fuel costs; and
- Fuel oil costs.

Submissions made by the parties on OPG's nuclear production forecast (Issue 5.1) are discussed above in Section 6.1. OPG is seeking approval of the nuclear production forecast shown in Chart 6.1 in Section 6.1 above. The approved nuclear production forecast will be combined with the agreed upon nuclear fuel bundle unit cost (per the Settlement Agreement, as noted above) to determine the annual nuclear fuel bundle cost included in the revenue requirement.

OEB staff concur with OPG's forecasts of used nuclear fuel storage and disposal variable costs and fuel oil costs (*Id.*). Used nuclear fuel storage and disposal variable costs (Issue 8.2) are covered further in Section 9.2.[59]

LPMA also agree with OPG's fuel oil costs forecast (LPMA argument, p. 15) and no parties raise objections to this forecast.

7.4 Issue 6.4

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

OEB staff and PWU agreed that the forecast DRP-related OM&A budget for the 2017-2021 period is reasonable, while QMA adopts OEB staff's proposal (OEB staff, p. 65; PWU argument, para. 2). LPMA also accepts the OM&A forecast for the DRP-related costs (LPMA argument, p. 16). No parties objected to OPG's submissions.

7.5 Issue 6.5

Oral Hearing: Are the test period expenditures related to extended operations for Pickering appropriate?

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[59] OEB staff's proposal under Issue 8.2 to reflect changes to nuclear liabilities costs in the revenue requirement rather than flow them through the applicable deferral and variance accounts would impact the forecast of used fuel costs reflected in the revenue requirement.

7.5.1 Introduction

This section responds to the submissions of OEB staff, AMPCO, CME, CCC, EP, ED, GEC, LPMA, QMA and SEC on the costs required to operate six units at Pickering to 2022 at which point two units would shut down and the remaining four would operate to 2024 ("Extended Operations").[60]

The PWU and SEP submissions support OPG's position on this issue (PWU argument, paras. 55-91; SEP argument pp. 10-11). As OPG agrees with both the facts and the supporting arguments presented, particularly the legal analysis advanced by the PWU, OPG provides no further reply to them.

OPG's response begins by discussing the reasons why the OEB should reject the submissions of ED, GEC and SEC, which invite the OEB to assume the system planning role that legislation has assigned to the Minister of Energy. The response next addresses the mischaracterization of the IESO's analysis and testimony to place them in proper context and refute parties' claims. Then OPG addresses comments on the nature of the Government's approval of Extended Operations and shows that OPG has consistently recognized that the Government's approval is subject to the regulatory decisions by the CNSC and OEB. Finally, OPG refutes the various proposals that seek to defer the costs of Extended Operations for future consideration or reject them altogether and shows that the proposed reductions are unwarranted and deferring these costs for future consideration is both unnecessary and impractical.

Before moving to the substance of the argument, OPG wishes first to address the inaccurate claim by SEC, ED, GEC, and CME that funding Extended Operations, and indeed allowing Pickering to operate beyond either 2018 (ED and GEC) or 2020 (SEC, CME) will harm customers. They offer no evidence to support this claim and the facts are undeniably to the contrary. It is beyond reasonable dispute that if Pickering were to be shut down before the end of the IR term, customers will pay more.

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[60] As AMPCO and QMA fully adopt the submissions of OEB staff on this issue they will not be mentioned further in this section.

SEC claims to acknowledge this fact, but does so incompletely (SEC argument paras. 7.4.4-7.4.5). SEC mentions the payment amount increase in 2021 due to the severance costs OPG will incur upon shutdown, but fails to acknowledge the much larger impact from the loss of Pickering production, which would adversely impact customers in two ways. First, it would cause OPG's unsmoothed payment amounts to about double in 2021 as the higher costs would be spread over less than half of the currently forecast 2021 production (Ex. E2-1-1, Table 1). At the same time, customers would pay to purchase replacement power for Pickering's lost production. SEC argues, however, that even if it ends up costing customers more, it does not matter because less money will go to OPG and in the end ratepayers will, somehow, be better off (SEC argument, para. 7.4.5).

In a similar vein, CME's claim that OPG is indifferent to Pickering's economics is incorrect (CME, para. 256). To the contrary, OPG testified that if it became clear that the costs of the project were materially higher, OPG would advise its Board of Directors and seek direction (Tr. Vol. 14, p. 154, lines 5-22).

OPG also wishes to dispel the suggestions by ED and GEC that the IESO does not support moving ahead with Extended Operations. The IESO's testimony on this point is unambiguous:

> I think on balance -- I know that on balance, we thought this has enough merit that it should be developed. For 300 million, $307 million, to preserve an option of extending an existing asset for another four years, I think on balance, in spite of all the uncertainties and the risks, I think that's a good idea.
>
> Mr. RUBENSTEIN: So at the time you finished producing this document -- put aside the technical ensuring it can be done and various other regulatory requirements that need to be done -- was it the IESO's view that as a system planner, Pickering should be extended to 2022-2024?
>
> MR. PIETREWICZ: Again, I think our view is pretty clear in this deck. We said this has benefit and should be explored further, and we're categorical about that.
>
> What should be explored? We're aware that this is a first cut idea. There are probably details that need to be figured out, and I understand that since that time, OPG has developed this concept further including with information that were provided to us for our October analysis.
>
> So I know this seems very -- kind of dark. Maybe it's just me; I'm less likely to celebrate some of these kinds of ideas. But I think our advice is indicative of <u>our support of moving ahead.</u> (Tr. Vol. 12, p.112 (emphasis added)).

7.5.2 The Scope of Issue 6.5 Does Not Include System Planning

As the OEB held in ruling on ED's discovery motion: "The scope of the OEB's review in issue 6.5 is to assess the appropriateness of the expenditures related to PEO" (Decision and Order on Motion filed by Environmental Defence, p. 4). In OPG's respectful submission, this scope does not involve a determination of the need for Pickering to continue operating or comparing Pickering against other electricity resources. These are determinations properly made by the Minister of Energy as Ontario's electricity system planner.

Parties advance two arguments to support their view that the OEB should determine whether Pickering is needed. The first, advanced by SEC, GEC, and echoed by others, is that a determination of need (SEC) or cost effectiveness (GEC) is fundamental to determining costs. SEC argues this most directly by stating "in making its determination whether costs are reasonable, the Board <u>must</u> determine if there is a need for the underlying asset or activity that warrants the expenditure" (SEC argument para. 7.4.6 (emphasis added)). Though SEC says this is something that the OEB must do, they fail to point to a single instance in this proceeding or in any of the previous OPG Payment Amount Applications where the OEB has determined whether a prescribed facility should continue operating. SEC's failure to offer any support for this position is unsurprising because the OEB has never done this and when previously asked to make similar determinations, it has consistently declined, as explained below.

GEC argues that OPG has the burden of proving Pickering's cost-effectiveness without ever explaining how cost effectiveness applies in the context of the OEB's mandate under Section 78.1 of the *OEB Act* to set just and reasonable payment amounts. GEC also fails to articulate the test that the OEB should use to evaluate cost effectiveness (GEC argument, pp. 4-5). Finally, GEC does not explain why this test, however defined, should apply to Pickering alone among OPG's prescribed generating facilities.

OPG submits that the reason GEC's proposed "cost effectiveness" requirement must fail is that "cost effectiveness" can only be assessed in the context of alternatives. In other words, the question "Is Pickering cost-effective?" can only be answered having regard to another question: "compared to what?" As discussed in detail below, the OEB previously has found that the evaluation of alternative resources is a system planning function that is outside the

OEB's statutory mandate to set payment amounts for OPG's prescribed facilities (Decision and Order on Motion by Environmental Defence, p. 5).

The second argument advanced by various parties is based on the amendment to O. Reg. 53/05 that requires the OEB to accept the need for the DRP, but does not mention Pickering. Parties argue that this necessarily means that the OEB is free to review the need for Pickering (SEC argument, para. 7.4.6, GEC argument, p. 4, CME argument, para. 253(b)). This interpretation is wrong from both a legal and a practical perspective. From a legal perspective, implicit in this interpretation is the view that system planning responsibility resides with the OEB unless explicitly removed from its jurisdiction by Government regulation. This interpretation has it backwards and, if accepted, would place the O. Reg. 53/05 amendment in direct conflict with the subsequently enacted Bill 135, which assigns system planning responsibility to the Minister of Energy (*Electricity Act, 1998*, Section 25.29(1)). An interpretation that creates a conflict between a regulation and enacted legislation should be rejected if there is an interpretation that is consistent with the legislation (*Matt v. Crawford*, 2010 ONSC 3980).[61]

A more reasonable interpretation of the amendment, and one entirely consistent with Bill 135, is that the requirement for the OEB to accept the need for the DRP was included to confirm that the Government had already determined need. This confirmation was desirable given that the legislation assigning system planning responsibility to the Minister of Energy, while pending at the time O. Reg. 53/05 was amended, had yet to be approved.[62]

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[61] In *Matt v. Crawford*, 2010 ONSC 3980, the Ontario Superior Court of Justice states:

> 12. There are established principles which govern the interpretation of legislation. Regulations are subordinate to statutes.
>
> 13. It is presumed that regulations are intended to work together with enabling legislation and with other Acts and regulations. Where conflict is unavoidable between the regulations and statute, the statute shall prevail, otherwise the courts prefer an interpretation which permits giving effect to both. Where there is conflict, and one provision deals with the matter specifically, the conflict may be resolved by applying the specific provision to the exclusion of the more general, but this applies to provisions on an equal footing — statutory or regulatory. A presumption may be applied that the legislature does not intend to delegate power to interfere with vested rights: Ruth Sullivan, Dreiger On the Construction of Statues, 3 rd ed., (Butterworths, 1994) at pp 185-186, citing Friends of the Oldman River Society v. Canada (Minister of Transport), [1992] 1 S.C.R. 3 (S.C.C.) per Laforest, J.

[62] The Government introduced Bill 135 which assigns system planning responsibility to the Minster on October 28, 2015, but it was not enacted by the Legislature until June 2, 2016 and received Royal Assent a week later. While Bill 135 was pending, the Government enacted O. Reg. 353/15, which amended O. Reg. 53/05 by introducing rate smoothing and making other changes relevant to the OEB's anticipated consideration of the DRP in OPG's next rate application including removing consideration of the need for Darlington from the proceeding.

As a practical matter, the same amendment that required the OEB to accept the need for the DRP also added explicit mention of the DRP to O. Reg. 53/05 section 6(2)4 which mandates recovery of costs incurred to "increase the output of, refurbish or add operating capacity to a generation facility…" The fact that the DRP is explicitly mentioned in this section cannot credibly be taken to suggest that other projects meeting the listed criteria are now ineligible for CRVA coverage because they are not mentioned, and no party has taken this position.

OPG respectfully submits that the OEB should reiterate its previously expressed view that the selection among alternative resources whether denominated in terms of "need" or "cost effectiveness" is a system planning function. By statute, the Minister of Energy is the system planner (*Electricity Act, 1998*, Section 25.29(1)). The role of the OEB in this proceeding is to determine the amount of Pickering's cost that should be included in setting OPG's payment amounts and not to decide whether Pickering should continue to be part of Ontario's electricity resource mix.

This view of the OEB's responsibilities under section 78.1 of the *OEB Act* has been consistently endorsed by the OEB in past payment amount proceedings. In the very first proceeding for OPG (EB-2007-0905), the OEB addressed intervenor arguments that it should decide the viability of continuing to operate Pickering. In response the OEB said:

> This aspect of the decision gives rise to two significant issues. The first is whether the Board has the jurisdiction to determine the viability of the Pickering stations. ... With respect to the first issue, the Board agrees with OPG that the Board's role in this application is to review the proposed costs of the prescribed facilities and to order reasonable payment amounts. (EB-2007-0905, Decision with Reasons, p. 28).

In EB-2010-0008, the OEB first considered the issue of Pickering continued operations. Again, despite intervenor requests that the OEB evaluate the need for Pickering, the OEB found that its role is limited to determining whether the planned spending on continued operations is reasonable. On this basis it approved OPG's spending request (EB-2010-0008, Decision with Reasons, pp. 51-52).

When faced with another invitation to expand the scope of the Pickering continued operations issue in EB-2013-0321, the OEB once again held that its role is to evaluate costs and declined to broaden the issue, stating: "The Board agrees with OPG that generation planning is not within the scope of this proceeding." (EB-2013-0321, Procedural Order No. 10, p. 3). Again the OEB approved the costs of continued operations (EB-2013-0321 Decision with Reasons, pp. 50-51).

The OEB decisions in the above noted proceedings respected the statutory allocation of responsibility for system planning. That responsibility now rests with the Minister of Energy. On this basis, the OEB should again decline to address the question of the need for Pickering to operate.

7.5.3 The OEB Was Correct in Deciding Not to Require an Updated IESO Analysis

Several parties criticize the IESO's analysis of the options for extending Pickering's operation and state that OPG's evidence is deficient because it failed to provide an updated IESO analysis during the course of the proceeding (CCC argument, p.19; ED argument, para. 42; EP argument, p, 22; GEC argument, p. 5; LPMA argument, p.16; SEC argument, para. 7.4.16). ED goes further and attempts in its argument to demonstrate that an update would prove Pickering is uneconomic (ED argument paras. 45-65). These parties ignore the fact that the OEB has already found that an update to the IESO analysis was not required (Decision and Order on Motion by Environmental Defence, p. 4).[63]

Fundamentally, the IESO analysis was provided to the Ministry for the Minister's use in deciding whether to approve OPG's pursuit of Extended Operations. Given that the Minister has announced his decision, the attempts by ED and GEC to provide biased, selective and incomplete updates to the IESO analysis should be rejected because they serve no purpose in deciding the issue currently before the OEB.

Because the claims of ED and GEC are not properly within the scope of Issue 6.5, OPG will not refute the myriad individual inaccuracies, incorrect assumptions and mischaracterizations of the evidence they contain.[64] Rather, OPG will make four general points about these arguments:

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[63] This finding was reiterated during the oral hearing (Tr. Vol. 8, pp. 67-69; Vol. 12 pp. 43-44).

[64] ED's Table 2 (ED argument, para. 61) exemplifies why these untested calculations cannot be relied on by the OEB. ED's Table 2 has the following obvious and material errors; 1) it treats the results of the IESO's 2018 closure scenario and 2022/24 closure scenario as additive, which they are not because in both scenarios the IESO is calculating savings relative to a 2020 closure (Ex. F2-2-3, Attachment 1, p. 61); 2) it intermingles US and Canadian dollar figures; and 3) it nets the cost savings in the 2018 scenario against the cost savings in the 2022/24 scenario.

- These purported "updates" are biased. Effectively what is being presented is a "one-sided" sensitivity analysis, with all inputs skewed towards the goal of trying to prove that Pickering is uneconomic. This is clearly seen in the lack of any real attempt to incorporate the range of carbon prices currently forecast.

- The approach of individually updating certain variables while ignoring other changes is fundamentally incorrect. Given the many interrelationships among the variables, it is not possible to simply sum the modifications of individual assumptions and produce a coherent result. As Mr. Pietrewicz stated, the IESO performed an assessment of integrated power system impacts (Tr. Vol. 12, p. 110, lines 11-16). Thus any reassessment would require a comprehensive update of all input assumptions and a re-running of the IESO's system planning models.

- Claims that Pickering's costs have increased substantially since the IESO analysis was completed are incorrect (ED paras. 35 to 41; EP paras. 4.23 to 4.29; CME para. 245). ED's submissions state: "However, OPG now admits that the cost to operate Pickering is actually **22% higher** than the costs provided to the IESO and used in its cost-benefit analysis." (ED's argument, para. 35 (emphasis in the original)). OPG submits that with this statement ED has exited the realm of vigourous advocacy and entered the land of "alternative facts." ED's compendium compared the incremental costs appropriately used in the IESO's analysis with OPG's current estimate of <u>fully allocated costs</u> (Tr. Vol. 13, p. 137). While OPG's witness confirmed ED's math, he also pointed out the difference between incremental and fully allocated costs (Tr. Vol. 13, pp. 137-138). Elsewhere, OPG provided ED with a complete reconciliation of the incremental and fully allocated costs including explanations of why certain costs are non-incremental (Ex. JT2.5). Finally, and contrary to ED's submission, the IESO was fully aware of the difference between incremental and fully allocated costs because OPG had provided the IESO with both (compare ED argument, para. 41 with Tr. Vol.12, pp. 16-17).

- Finally it is worth noting, as Member Spoel did, that none of the parties criticizing the IESO studies and OPG's economic analysis elected to provide studies of their own and have them subject to cross examination (Tr. Vol. 8, p. 83). Instead, these parties have chosen to present this material in argument where it cannot be tested.

Below OPG responds to the parties' criticisms of its evidence by demonstrating that the IESO analyses were timely when submitted and represent the best evidence of the analytic bases for the Minister's decision to approve OPG's pursuit of Extended Operations. Furthermore, as the IESO undertook theses analyses at the request of the Ministry of Energy, any request for an update also would have had to come from the Ministry and not from OPG (Tr. Vol. 8, pp. 39-41).

To support ongoing system planning efforts, the Minister requested that the IESO compare the costs associated with various Pickering operating scenarios against the costs of reasonable alternatives. This resulted in two IESO analyses, the first dated March 9, 2015 and a second updated analysis dated November 4, 2015 (Ex. F2-2-3, Attachment 1, pp. 1, 42). OPG included both IESO analyses with its Application so the OEB and the parties could see the analyses that the Minister had available when he approved OPG's plan to pursue Extended Operations on January 11, 2016.

Parties criticize OPG for not submitting an updated IESO analysis (GEC argument, p. 5; SEC argument, para. 7.4.16). Some go so far as to state OPG has failed to meet its burden of proof (GEC argument, p. 5). Others call on the OEB to require that OPG file an updated IESO analysis in the context of the mid-term review (SEC argument, para. 7.4.16; CME argument, para. 259; CCC argument pp.18, 21). These criticisms are without merit and there is no need for further analyses.

OPG's Application was filed on May 27, 2016. At that time, the updated IESO analysis was less than seven months old. As the OEB recognized in its decision on ED's discovery motion: "The analysis is done at a specific point in time. It will never remain static but will always be in need of updating." (Decision and Order on Motion by Environmental Defence, February 16, 2017, p. 4). The OEB also found that: "The IESO and OPG have submitted that no further updates have been prepared. The OEB accepts this response." (*Id.*).

OPG submits that by any objective measure, the IESO analyses were not outdated when filed. To the contrary, they represented the then current analyses available from the IESO.[65] As such, they constitute the best evidence of the basis for the Government's support for the project and there was no need to update them. The OEB reached a similar conclusion in EB-2013-0321 in rejecting calls for an updated analysis of the benefits from Pickering Continued Operations (EB-2013-0321, Decision with Reasons, p. 51).

As to GEC's comment that OPG "elected" not to update them (GEC argument, p. 7), OPG has two responses. First, OPG does not set the IESO's work plan. The Government asked the IESO to perform the original study and the subsequent update. As confirmed by the IESO, no further updates were performed (Ex. L-6.5-5 CCC-34). As far as the economic analysis

[65] Another reason that OPG determined to submit the IESO analyses with its Application was the fact that in EB-2013-0321 the OEB cited a similar analysis by the OPA in approving the costs of Continued Operations (EB-2013-0321, Decision with Reason p. 51: "Further, benefits from Pickering continued operations were confirmed by the OPA.").

performed by OPG as part its request for approval of Extended Operations from the OPG Board of Directors, once the requested approval was granted, there was no need to update the business case, particularly in light of the subsequent IESO analysis, which directionally confirmed OPG's results.[66]

7.5.4 OPG Has Consistently and Correctly Characterized the Government's Approval of Extended Operations

OPG filed Ex. F2-2-3 in support of its request that the OEB approve the costs of Extended Operations. At page 3 of that exhibit, OPG states:

> On January 11, 2016, the Minister of Energy announced that the Government had approved OPG's plan to pursue Extended Operations. Leading up to this announcement, the Ministry of Energy had been working with OPG and the IESO to analyze the technical feasibility, costs and benefits of Extended Operations.

Exhibit F2-2-3 went on to explain that pursuit of Extended Operations required OPG to complete certain technical analysis and renew Pickering's power reactor operating licence from the CNSC (Ex. F2-2-3, pp. 5-9).

ED, GEC and SEC claim that OPG has mischaracterized the nature of the Government's approval. They state, incorrectly, that OPG has implied that the Government's approval is final and not subject to change. In support of this claim they point to statements by the Deputy Minister of Energy in response to questions from the NDP Energy Critic (GEC argument, p. 4; ED argument para. 73; SEC argument para. 7.4.8). OPG submits that its evidence and the Deputy Minister's statements are completely consistent.

GEC, SEC and ED claim that the Deputy Minister has stated that the Government's approval is not final as OPG must still conclude regulatory processes at the CNSC and OEB. In interrogatories, GEC posed the following question:

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[66] SEC claims that OPG has not received final approval for Extended Operations from its own Board of Directors (SEC argument, para. 7.4.18). This claim is incorrect and is not substantiated by the transcript reference that SEC provides. OPG's Board of Directors has approved Extended Operations (Ex. F2-2-3, p. 2). It also approved an initial funding release of $52M (Ex F2-2-3, Attachment 2, p. 5). While OPG management will return to the Board of Directors for a subsequent release of the remaining enabling funds, this will not be a request to re-approve the project.

> (b) Please confirm that a final decision on the Pickering service life will not occur until fuel channel life management work is completed and a relicensing decision is issued by the CNSC. (Ex. L 6.5-8 GEC 21(b)).

OPG responded as follows:

> (b) Since Pickering can only operate pursuant to a licence from the CNSC, no decision on the plant's service life can be final until the CNSC issues its relicencing decision. (Ex. L 6.5-8 GEC-21(b) (emphasis added)).

Thus the understanding reflected in OPG's evidence is the same as that articulated by the Deputy Minister.

In a similar vein, OPG has consistently acknowledged that the OEB has broad discretion to set payment amounts and that OEB approval is necessary to recover the costs of Extended Operations (OPG Reply Submissions To Motions, p. 3, paragraph 10).

To conclude on this issue, what GEC presents as a "subsequent clarification" of the Minister's support for Extended Operations is in fact entirely consistent with OPG's understanding of his original statements and intent. While OPG agrees that the decision on Extended Operations cannot be final until the necessary regulatory approvals have been obtained, this should not be taken to mean that the Government is reassessing its expressed support for Extended Operations.

To eliminate any doubt that the Minister of Energy continues to support Extended Operations, OPG attaches as Appendix A, the Minister's May 30, 2017 Letter concurring with OPG's 2017-2019 Business Plan.[67] There the Minister writes:

> We continue to support the planned operation of Pickering units up to 2024, subject to OPG obtaining necessary regulatory approvals, as the station's output will provide reliable, cost-effective and emission-free electricity supply during the Darlington and initial Bruce refurbishments. I expect OPG to keep the ministry apprised throughout the regulatory processes and as we proceed to update the Long-Term Energy Plan.

[67] In Ex. JT2.1, OPG was asked: "To file the Ministerial Concurrence Letter."

7.5.5 Strong Likelihood of Approval

OEB staff and other parties point to two approvals that are required for Extended Operations: inclusion in the 2017 LTEP and a receipt of CNSC operating licence renewal (OEB staff argument, pp. 97-98; CCC argument, pp. 18-20). OPG agrees that these actions are required, but submits that there is every reason to believe that they will be granted.

OPG's AIC detailed the documents and actions that indicate the Minister's support for OPG's Extended Operations plan (AIC, pp. 89-90). OEB staff agree with some of this evidence and are silent on the remainder; they do not dispute any of it (OEB staff argument, p. 97). Other parties dismiss this information as either not determinative (SEC argument, para. 7.4.10) or, as discussed above, superseded (GEC argument p. 4; SEC argument, paras. 7.4.8 to 7.4.10).

Neither OEB staff nor any other party provide any additional evidence indicating that the Minister is unlikely to include Extended Operations in the 2017 LTEP. They only raise this as a possibility. Until the 2017 LTEP is issued, OPG acknowledges that there is some chance, however small, that the 2017 LTEP will not include Extended Operations. OPG submits that based on the IESO's continued support for the project, which OEB staff acknowledge, but other parties discount, and the Government documents and actions previously discussed, the balance of probabilities weighs strongly toward the conclusion that Extended Operations will form part of the 2017 LTEP.

As for CNSC approval to operate Pickering beyond 2020, OPG again submits that there is every reason to believe that it is likely. The following facts support this view:

- OPG has conducted the technical assessments necessary to support operation of all six Pickering units to at least 2022 (Tr. Vol. 15, p. 146). CNSC staff have concurred with these assessments (Tr. Tech. Conf. Vol. 2, pp. 82-83).
- OPG has completed the Fuel Channel Life Assurance project. The Periodic Safety Review and condition assessments are nearing completion. The work is progressing very well and showing positive results (Tr. Vol. 13, p. 177).
- OPG successfully completed Pickering Continued Operations on time and on budget, which will allow Pickering to operate to 2020. This work is similar to that required for approval of Extended Operations (Tr. Vol. 15, p. 145).

The parties' submissions do not refute any of these facts and offer no other evidence that would tend to decrease the likelihood of CNSC approval to operate Pickering as OPG proposes. Again, OPG acknowledges that until an approval is actually received, there is always some possibility that it will not be granted or that that the approval will include conditions that render operation to 2022/24 impractical.[68] OPG discusses how best to proceed in this scenario in the following sections. In this case, however, all the evidence points to the conclusion that the 2017 LTEP and CNSC will provide the approvals necessary for Extended Operations.

7.5.6 Deferring Consideration of the Costs of Extended Operations is Impractical and Unnecessary

OEB staff seek to defer $211M in enabling costs that OPG forecasts spending in 2019 and 2020 for the technical work necessary for Extended Operations and an additional $250M for restoration of normal operating costs to be spent over the period 2017-2020.[69] The latter amounts reinstate funding for normal operating activities that OPG had planned to reduce when Pickering operations were scheduled to end in 2020. Under OEB staff's proposal, the deferred enabling costs would be recovered through the CRVA while the restoration costs would be tracked for future recovery in a new deferral account to be created for that purpose. OEB Staff also suggest that OPG consider delaying the spending necessary to restore normal operating costs, but as discussed below, this is not possible. The sole basis offered for the proposed deferral is that Extended Operations may not be approved.

The remaining parties submit a range of proposals for deferring or limiting funding for Extended Operations. As discussed above, these proposals are based on the fact that the 2017 LTEP and CNSC licensing decision are pending and on these parties' unfavourable view of the relative economics of Extended Operations. Their proposals are as follows:

- CME and EP recommend that no costs beyond those in 2017 be approved (CME argument, para. 259; EP argument, para. 4.48).

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[68] During the hearing OPG acknowledged that it is possible, but unlikely, that the CNSC could require conditions that would cause OPG not to proceed with the project (Ex. L-6.5-1 Staff-117).

[69] OEB staff's statement that: "These are costs to prepare the Pickering units for operation beyond 2020 and are needed only if the project proceeds as planned." is incorrect (OEB staff argument, p. 98). Once OPG made the decision to pursue Extended Operations, it began incurring enabling costs and is currently incurring both enabling costs and the costs to restore normal operations. OPG cannot stop these expenditures and then restart them when all approvals are known, as explained later in this section.

- CCC recommends that the costs could be considered in the mid-term review, but does not state how the OEB should treat the normal operating costs, which are not subject to a variance account, in the interim (CCC argument, p. 21).
- ED recommends that no costs beyond 2018 be approved, although ED's alternative suggestion is that approval of any post-2018 costs be subject to an updated cost-benefit analysis that addresses the issues that they and other intervenors raised (ED argument, paras.79-81)
- GEC's recommendation is similar to ED's, either disallow all post-2018 Pickering costs or approve the 2017-2018 payment amounts on an interim basis and make a final determination on the amount of Pickering costs to include once the Government has definitively indicated that Pickering should operate (GEC argument, p.15).
- LPMA's proposal is similar to that of OEB staff on enabling costs, except it would use the CRVA to track the 2019-2020 amounts rather than defer them, or include them in rates on an interim basis. On restoration of normal operating costs, LPMA supports the OEB staff proposals (LPMA argument, pp. 16-17).
- SEC proposes that the enabling costs be disallowed unless subsequent analysis shows system benefits and that payment amounts be set assuming that Pickering will cease operating in 2020. SEC recognizes that this approach will increase the 2021 payment amounts, but makes no proposal on how these increases should be addressed (SEC argument, paras. 7.4.3-7.4.4).

As previously discussed, OPG believes that OEB staff and other parties have overstated the risk that Extended Operations will not be approved through the CNSC licensing process or included in the 2017 LTEP. Even if the OEB were to agree with these parties' assessment of the risks of non-approval, however, OPG submits that the OEB should still reject the proposed deferrals and disallowances. Simply put, if Extended Operations receives the necessary approvals, the proposed deferrals and disallowances would be unnecessary. If Extended Operations is not approved, they would again be unnecessary because OPG would be required to file a new application with the OEB and has committed to do so (Tr. Vol. 6, pp. 157-158).

On a more pragmatic level, parties' deferral proposals are unworkable as proposed. OPG's Application is based on the 2016-2018 Business Plan, which assumes Extended Operations. OPG's cost projections for outages, capital projects, OM&A and staffing all rest on this planning basis. In 2017, OPG cannot both retain the staff required to accomplish the work necessary to operate Pickering to 2022/24 and yet not be funded to undertake this work as parties propose. Similarly, the OEB cannot set nuclear payment amounts using a production forecast that is predicated on OPG undertaking the outages required for Extended Operations, without providing the funding to support these outages. Simply put, if the OEB determines to set payment amounts on an assumption other than Extended Operations, it will necessarily impact virtually every aspect of the nuclear revenue requirement.

7.5.7 Parties Extended Operations Proposals Do Not Align with Their Submissions in Other Areas

OEB staff and other parties appear to treat their proposals to defer or disallow certain Extended Operations costs as being unrelated to their positions on the remainder of OPG's Application. As mentioned previously, OPG's work program in both the 2016-2018 Business Plan that underpins OPG's Application and the more recent 2017-2019 business plan includes undertaking the work necessary for Extended Operations.

In effect, OEB staff and parties are proposing that for purposes of Extended Operations' costs, the OEB should assume that Extended Operations will not be approved, but for purposes of the remainder of the Application, the OEB should assume that Pickering will operate beyond 2020. This inconsistency in approach is most easily seen in two areas: the production forecast and 2021 costs.

In its submissions on the production forecast, OEB staff note that OPG includes 637 outage days over the 2016-2020 period to enable Extended Operations, which equates to a 7.5 TWh decrease in production (OEB staff argument, p. 69). While staff propose increasing Pickering's forecast production in the first three years of the IR term and exclude Pickering production from the mid-term review, they do not recommend any changes to the number of outage days forecast for Extended Operations or dispute that the production forecast should assume Extended Operations.

OEB staff's submissions on the mid-term review explicitly state "OEB staff submits that any event requiring Pickering to shut down sooner than OPG plans would result in an application to the OEB at the time of the event." (OEB staff argument, pp.172-173). If OEB staff view OPG's commitment to file a new OEB application as sufficient for mid-term review purposes, it should suffice equally well for cost forecast purposes. SEC argues that the OEB should deny all funding for Pickering post-2020, but makes no submissions at all on OPG's production forecast, which has Pickering producing 18.8 TWh in 2021 (SEC argument, para. 6.1.1; Ex. E2-1-1, Table 1).

Obviously, if Pickering ceases commercial operation in 2020, its costs in 2021 will change dramatically. The submissions by OEB staff and other parties proposing deferrals or disallowances fail to acknowledge this fact. OEB staff submit that:

> 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. (OEB staff argument, p. 98)

Thus OEB staff propose that recovery of the restoration of normal operating costs in 2017-2020 be fully deferred, while at the same time proposing that the normal operating costs for 2021 be recovered, subject to OEB staff's general OM&A adjustments. The differing treatment proposed for recovery of the same types of OM&A costs in different years is difficult to reconcile.

7.5.8 How Best to Proceed in the Interim

Given that the necessary approvals have not yet been obtained, the issue before the OEB here is how best to proceed in the interim, while the 2017 LTEP and CNSC decisions are pending. OPG submits that the simple answer is the correct one - approve the funds requested to enable PEO and to restore normal operations and require OPG to file a new application if the necessary approvals for Extended Operations are not issued or OPG determines it cannot proceed with the project. In the paragraphs that follow, OPG demonstrates why this approach is more appropriate than the deferral and disallowance proposals advocated by OEB staff and other parties.

As OPG's evidence shows, the expenditures necessary to enable Extended Operations began in 2016 and continue through 2020 (Ex. L-6.5-1 Staff-116). OEB staff would have the OEB approve the 2017 and 2018 enabling costs and defer the remaining expenditures in the CRVA for future disposition. The restoration costs began in 2017 and continue to 2020 (*Id*.). While OEB staff do not question the quantum of restoration costs, they propose that all of these costs be deferred, including the amounts that are currently being spent. OEB staff, with support from LPMA, suggest that OPG attempt to delay spending the restoration costs until after the CNSC decision is received (OEB staff argument, p. 98), but this suggestion is unworkable as these are normal operating costs that are incurred on a daily basis to support Pickering's operation.

For example, these costs include training required to ensure that OPG has sufficient authorized staff to operate Pickering beyond 2020 (Ex F2-2-3. Attachment 2, p. 14). Given the three years required to train these staff (Tr. Vol. 15, p.157), it is not possible to delay this spending.

For the enabling costs, OEB staff's proposal will create new D&V account entries for costs that are known today and that OEB staff do not dispute. OPG had already committed to tracking the enabling costs in the CRVA; so while the proposal would unnecessarily increase the CRVA balances, it would pose no tracking issues. To avoid increasing CRVA balances, LPMA suggests that these costs be approved now, but subject to refund through the CRVA if Extended Operations does not proceed (LPMA argument, pp. 16-17).

Restoration costs are different because these are normal operating costs that had been expected to decrease when OPG planned to end commercial operations at Pickering in 2020 (Ex. F2-2-3, p. 6, lines 16-22). OPG's 2017 to 2020 spending includes amounts to restore operating costs to normal levels. While OPG could simply place the forecast amounts in a deferral account, for 2017 this would mean deferring amounts that OPG has already spent and, again, that OEB staff do not directly dispute.[70] Because restoration costs are comingled with, and indistinguishable from all other operating costs, OPG did not establish any separate tracking for them in its most recent Business Plan (2017-2019). In practical terms, these costs cannot be tracked without an unreasonable level of effort and the exercise of significant judgment, making the deferral proposals of OEB staff and other parties unworkable.

Under OPG's approach, the deferral of known and largely undisputed costs is unnecessary, as is the effort to track a sub-set of ongoing operating costs. If Extended Operations is approved as expected, no further OEB action would be necessary. If approval is denied, OPG would return to the OEB with an application based on an integrated view of the costs and production associated with the planned Pickering shutdown. As the evidence demonstrates, the 2021 costs would include significant severance payments and related costs under that scenario (Ex. L-6.5-1 Staff-118, Table 2).

[70] OEB staff and other parties have challenged portions of OPG's overall OM&A costs. While no party has directly questioned the forecast restoration costs, because these costs are recovered through nuclear and corporate support OM&A, it is fair to say that OEB staff and other parties have indirectly challenged a portion of them (Ex. L-6.5-1 Staff-118).

Based on the foregoing, OPG respectfully requests that the OEB decline to defer or disallow both the enabling costs and the restoration of normal operating costs for Extended Operations. Instead, the OEB should approve the requested costs and require OPG to file a new application if Extended Operations does not proceed.

7.6 Corporate Costs

7.7 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?

7.7.1 Introduction

This section discusses OEB staff and intervenor submissions on the compensation and benefits that OPG pays to its employees. OEB staff's submissions recognize that OPG has made progress in controlling both compensation costs and the number of employees (OEB staff argument, pp. 102, 112). Other parties descriptions of OPG's progress on compensation cost range from "slightly improving" (SEC argument, para. 7.5.2) to "clear improvement" (PWU argument, para. 118).

OEB staff, supported by VECC, propose disallowing $50M per year on account of excessive employee compensation and benefits primarily related to pension costs (OEB staff argument, p. 113; VECC argument, para. 11). AMPCO recommends an annual disallowance of $85M (AMPCO argument, para. 246). CME recommends an annual disallowance of up to $80M (CME argument, para. 279). CCC recommends that the OEB consider the disallowances proposed by OEB staff and SEC particularly with regard to pensions and benefits (CCC argument, p. 23). LPMA suggests an annual disallowance in the range of $56.7M to $70M (LPMA argument, p.18).[71] SEP propose disallowances of $20M in 2017, $10M in 2018 and zero in the subsequent years (SEP argument, p. 21).

[71] LPMA's argument for a disallowance includes $10 to $20M per year to incent OPG "to focus on continuing improvement and improving their benchmarking performance" (LPMA argument, p. 18). OPG notes that this is the purpose of the stretch factor, not disallowance. Therefore, a disallowance on this basis would result in double counting with stretch factor reductions.

SEC proposes disallowing at least $86.7M per year (SEC argument, para. 7.5.39). It argues that a large disallowance is necessary for the OEB to exercise its role as a market proxy (SEC argument, para. 7.5.5). In this context, it is revealing that neither SEC nor any of the other parties who claim OPG's compensation is unreasonable comment on the fact that the benchmarking of Bruce Power's wages by Willis Towers Watson ("Towers") shows that Bruce Power has higher wages for both PWU and Society positions (Ex. F4-3-1, pp. 21-22). Bruce Power operates CANDU technology in the same market as OPG and is OPG's closest competitor for attracting and retaining talent, and therefore would serve well as a market proxy.

Many of intervenor submissions continue to be critical of OPG in the area of compensation. For example, SEC begins its submission in this area by stating that OPG's proposed compensation is a "far cry from levels that can fairly be called reasonable" (SEC argument, para. 7.5.2), later claiming that OPG "has returned to its previous habits of paying unreasonable amounts to its employees" (SEC argument, para. 7.5.12). While OPG knows it must remain focused on making further inroads when it comes to certain areas of compensation, particularly pensions and benefits, it respectfully submits that this kind of rhetoric cannot obscure the clear evidence of substantial progress on both total direct compensation ("TDC") and pensions since EB-2013-0321 (see AIC, Section 7.7).

7.7.2 The Towers Benchmarking Study

OEB staff recognize that the Towers benchmarking study shows that OPG's TDC is at market, but suggest that because the study does not consider overtime expenditures or include the lump-sum payments and Hydro One share awards, the OEB should place less confidence in this result (OEB staff argument pp. 102-103). Other parties cite similar alleged deficiencies in the Towers benchmarking (SEC argument, para. 7.5.9; AMPCO argument, para. 237; CME argument, para. 266; VECC argument, para. 6.6.7). OPG submits that these concerns should not undercut the OEB's confidence in the results of the Towers study because those results were produced through the consistent application of industry standard benchmarking approaches and fully support the appropriate use of benchmarking.

While OPG responds to the specific points on benchmarking below, as an initial matter, OPG wishes to emphasize the inherent limitations of benchmarking. As the OEB stated:

> The Board is mindful that benchmarking, while useful, is not a precise tool. It provides a high level picture of OPG's compensation situation, but cannot be expected to produce an exact dollar figure by which OPG's compensation is too high (or, in theory, too low). (EB-2013-0321, Decision with Reasons, p. 80).

Any benchmarking exercise is necessarily a high level comparison because the tasks and accountabilities associated with reasonably similar jobs differ among companies. Nor is it possible to match every job at each of the comparator companies because some companies outsource certain work, while others combine various tasks and accountabilities into different jobs depending on their business needs. SEC appears to recognize this when it writes: "[a]t some level no two positions in different companies are the same. They each have unique features." (SEC argument para. 759(d)). As is discussed below, however, elsewhere in its submissions, SEC treats the benchmarking results as yielding a precise mathematical formula to calculate disallowances.

Benchmarking is, necessarily, an approximation. Recognizing these inherent limitations, OPG submits that the Towers benchmarking study undertaken for this case is a robust and independent examination of OPG's relative compensation that is based on industry standard methods and an appropriate comparator group.[72] For TDC, the study's directional findings demonstrate that overall, OPG is at market.

During the course of this proceeding, OPG explained in detail the methods that Towers employed and the data it used (see e.g., Ex. F4-3-1, Attachment 2; Ex. L 6.6-1 Staff-152 to 155; Ex. L 6.6-15 SEC-82 to 84; Ex. JT3.2). OPG has also demonstrated the many ways in which the Towers benchmarking has improved on the AON Hewitt ("AON") benchmarking filed in EB-2013-0321 (Ex. L 6.6-1 Staff-149; Tr. Vol. 16, p. 67, lines 18-28, p. 68, lines 1-8). For example, the Towers study uses a broader data set (i.e. the Towers survey database). This increased the number of OPG positions that could be matched, particularly in the General Industry segment,[73] permitted the inclusion of additional compensation components (i.e. long term incentives), and will allow OPG to repeat this study in the future on a comparable basis (Ex. L-6.6-1 Staff-149; Tr. Vol. 16., p. 69, lines 27-28, p. 70, lines 1-19, p. 71, lines 2-7). The

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[72] Contrary to VECC's claim (VECC argument, para. 6.6.9), the comparator companies selected by Towers provide appropriate comparisons for the positions in each segment (Ex. F4-3-1, Attachment 2, pp. 6, 29-33). See AIC, p. 109 for additional discussion of the comparator companies.

[73] The Towers study matched 78% of OPG's positions compared to 54% in the AON study. As discussed below, Towers matched 66% of general industry segment incumbents, while AON only matched 26% (Ex. J16.3).

Towers study also better segmented positions to allow for a more robust selection of comparator companies using a mix of 50% private and 50% public sector entities (*Id*.). Based on this, OPG submits that the Towers study represents a clearly positive evolution from the AON benchmarking in EB-2013-0321. As well, OPG has relied on the Towers study for internal purposes (Tr. Vol. 16, p. 49, lines 9-10; Ex. F4-3-1, p. 12).

Parties make submissions questioning the results of the Towers study, in large part, because it excludes certain elements of compensation. Before turning to specific elements referenced by parties, OPG notes that Tower's compensation benchmarking methodology compares the current compensation offered to new hires by the participating companies. Specifically, "[p]rogram costs that are not available to new hires are not typically included in this type of compensation benchmarking study as these programs do not reflect the ongoing compensation offering" (Ex. L-6.6-1 Staff-148). This was also the approach used by AON in the benchmarking study that OPG submitted in EB-2013-0321.

Regarding the lump sum payments and Hydro One share awards to represented staff, OEB staff submit that "[i]t is unlikely that OPG's comparators have similar incentives that have been excluded from their total direct compensation" (OEB staff argument, p. 103). AMPCO, CME, SEC, and VECC similarly comment that OPG failed to include these items (AMPCO argument, paras. 237-240; CME argument, para. 278; SEC argument, para. 7.5.9; VECC argument, para. 6.6.7).[74] OPG responds that without conducting a direct inquiry of each comparator company, it is not possible to determine which companies have provided lump-sum payments or the quantum of these payments, as this information is not routinely included in the Towers compensation data base. Moreover, since these are "one-time" payments, the results in one year would not reflect future years and, in any event, these payments are being provided in exchange for higher pension contributions, not in lieu of higher wage increases. For context, OPG also notes that, as the Towers study was conducted using data as of April 1, 2015, the inclusion of the "one-time" payments as part of that data would have totaled about $4M as only the 1% payment to PWU employees was in effect as of that date.

[74] SEC's argument incorrectly states: "Starting in 2017 and 2018 respectively, the PWU and the Society employees will earn in addition to their regular compensation, 2.75% of the value of their 2015 base compensation paid in Hydro One shares." The correct percentages and timing are as stated in OPG's evidence: "2.75 per cent of salary as of April 1, 2015 for PWU and 2.0 per cent of salary as of January 1, 2016 for Society" (Ex. F4-3-1, p. 17, lines 15-17).

OEB staff, AMPCO and CME also note that OPG's benchmarking results do not include overtime payments (OEB staff argument, p. 102; AMPCO argument, para. 237-240; CME argument, para. 278). In OPG's submission, this exclusion is not only appropriate, it is necessary because, as explained below, it is not possible to meaningfully benchmark the amount of overtime a company pays.[75] Towers recommended that overtime be excluded from benchmarking, as per standard industry practice (Ex. L-6.6-1 Staff-148).

Overtime is excluded from benchmarking because companies use overtime differently based on their business needs, resourcing strategies and the relevant provisions of their collective agreements (Ex. L 6.6-1 Staff-148). Moreover, within an individual company, the amount of overtime paid can vary year over year depending on the amount of unanticipated work and the urgency to complete it, actual staffing levels relative to planned levels, and the costs and availability of alternatives to overtime such as engaging temporary employees or purchasing external services. Because of these differences in companies' approach to using overtime and their need for overtime in any given year, industry practice is to exclude overtime from compensation benchmarking. A comparison of the overtime amounts paid by different companies in any given year would not produce meaningful information about their relative efficiencies in using overtime. OPG notes its continuing efforts to control overtime expenditures by requiring pre-approvals of overtime use in non-emergency situations, having executives and finance staff monitor overtime use and conducting periodic assessments of overtime use (Ex. F4-3-1, pp. 12-13).

OEB staff also suggest that the Towers results may be favourably impacted by the relatively lower number of General Industry positions covered in the study. As OPG explained:

> [Towers] was able to match 66% of the General Industry segment of OPG's population. According to WTW, this represents a strong level of representation of disciplines and levels across the General Industry segment. The purpose of benchmarking is to select an appropriate sample of jobs that create "apples to apples" comparisons of similar jobs across organizations. As noted in L-6.6-1 Staff-149 (b), compared to the previous benchmarking conducted by Aon Hewitt,

[75] It may be possible to benchmark overtime policies (e.g. when employees are paid at time and a half versus when they are paid double time), but not overtime amounts as the parties request. In OPG's case, since only represented employees receive overtime, the policies governing overtime payments are entirely a product of collective bargaining.

> the WTW benchmarking was able to benchmark more OPG positions and more appropriately match positions in the General Industry segment (see EB-2013-0321, Ex. F5-4-1). (Ex. J16.2).

In comparison to the 66% figure in the Towers study, in the benchmarking study submitted in EB-2013-0321, AON was only able to match only 26% of the incumbents in the General Industry segment (Ex. J16.3). Moreover, data provided in the Towers study shows that overall 23% of the incumbents matched were in the General Industry segment (Ex. F4-3-1, Attachment 2, p. 11).[76] Given that the General Industry segment comprises 27% of all OPG employees, it is clear that this segment is not significantly under-represented in the Towers study.

SEC, CME and VECC argue that Towers did not account for the fact that some OPG employees work 35 or 37.5 hours per week rather than 40 hours (SEC argument para 7.5. 9(e); CME argument para. 266; VECC argument, para. 6.6.7). OPG's response to Undertaking J17.13 puts this issue in perspective in a number of ways (Ex. J17.13). First, it shows that two out of three OPG employees have nominal work weeks of 40 hours. This figure is understated because while most management employees have a nominal 35 hour week, their typical work week is longer and management employees are not paid overtime. Second, it explains why Towers specifically rejected any adjustment for hours worked:

> Towers advises that for TDC benchmarking annualized salary is the most comparable element to use because it integrates various company policies such as paid time off, formal vacation and hours of work which different companies will use in different combinations. Making adjustments on one element such as hours of work without considering the other elements undermines the purpose of benchmarking which is to create as standardized a comparison as possible from one company to the next, recognizing that individual policies vary. (Ex. J17.13).

Finally, the fact that Towers did not adjust for the length of the work week while the Goodnight staff benchmarking did is fully explained by the different purposes of each study. The Towers study seeks to evaluate total direct compensation for comparable positions, where the factors noted above, such as vacation policy and other time off with pay, will influence the actual time employees spend at work, but not the tasks they perform or their level of accountability. In

[76] The calculation is as follows: Number of General Industry segment incumbents matched is 1,051+290+362, which totals 1,703. Dividing 1,703 by 7,380 (the total number of incumbents matched) equals 23%.

contrast, Goodnight benchmarked staffing levels, and as such, made an adjustment to the hours worked to compare the number of staff required for functions on an equivalent basis.

Benchmarking Nuclear Authorized Staff

OEB staff and other parties also dispute the use of the 75th percentile as the appropriate benchmark for the 4% of OPG employees that are in the Nuclear Authorized segment (OEB staff argument, p.104; AMPCO argument, para. 236; SEC argument para. 7.5.9(d)).[77] OPG has used this benchmark for the relatively small numbers of employees in this segment in recognition that the jobs they are doing are more complex and entail greater responsibility (Ex. J16.1; Ex. JT2.33; Tr. Vol. 16, pp. 56-69; Tr. Vol. 17, pp, 7-9; Ex. L 6.6-1 Staff-153). This complexity is based on the multiple systems that an authorized operator at a CANDU reactor must manage compared to an authorized operator in the U.S. (Tr. Vol. 17, pp, 8-9). As OPG testified:

> They would have a number of years' experience at the plant prior to entering the authorization program. That could be could be three, five, eight years, up to many more.
>
> But once they start the authorization program, it's essentially -- for an authorized nuclear operator, that's about a three-year process. And that's three years of intense training, a number of exams they have to write that are overseen by the CNSC, and that includes simulator training as well. So they have to go through a number of exams in the simulator. (Tr. Vol. 15, p. 157).

In contrast, training for equivalent positions in the U.S. is 14-16 months in duration (Tr. Vol. 16, p. 58, line 25 to p. 59, line 7).

OEB staff and other parties claim that this difference in complexity does not justify the use of the 75th percentile. However, Towers agreed that the differences in role complexity were sufficient to support OPG's use of the 75th percentile as the appropriate comparator for the nuclear authorized segment (Ex. L-6.6-1 Staff-153).

SEC speculates that there also might be other positions at OPG that are less complex than those at the comparator companies, but offers no evidence to support this point (SEC

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[77] Senior Executives in the Nuclear Authorized segment are benchmarked at the 50th percentile (Ex. F4-3-1, Attachment 2, p.20 (footnote)).

argument, para. 7.5.9 (d)). SEC's speculation is counter to OPG's testimony, which states that there is no indication of any difference in complexity between positions at OPG and those at other companies in any category other than the nuclear authorized segment (Tr. Vol. 17, pp. 9-10).

OPG submits that for the crucial role of licensed authorized nuclear operators who run the control rooms for the Darlington and Pickering nuclear reactors, it must be able to attract and retain the most qualified personnel. On this basis, using the 75th percentile for this small segment of employees is reasonable.

Extrapolation to the Entire OPG Population

On the issue of the dollar value associated with moving all OPG staff exactly to the 50th percentile, for the reasons discussed above, OPG submits that such an approach would ascribe a level of precision to benchmarking that is unrealistic. It is precisely for this reason that compensation professionals, like Towers, use a range to determine whether compensation is at market. Towers used a range of ± 10% in their study (Ex. F4-3-1, Attachment 1, p. 11).

In the hearing, SEC presented a calculation that combines the results of benchmarking the Nuclear Authorized Segment at the 50th percentile and moving all OPG employees exactly to the 50th percentile. Based on this calculation, SEC recommends a $46.7M compensation disallowance (SEC argument, paras. 7.5.14-7.5.15). This calculation is mentioned in the OEB staff argument and supported by other parties (OEB staff argument, p. 104; AMPCO argument, para. 246; CME argument, para. 274; LMPA argument, p. 18). As OPG testified, while the math may be correct, the granular extrapolation that SEC performed is incorrect because in certain segments, such as for PWU employees in the general industry segment where security positions were excluded, there is evidence that the positions that were not benchmarked would be closer to market than the positions that were benchmarked (Tr. Vol. 17, p. 31). As such, SEC's suggestion that OPG's security personnel are likely to be earning more than the benchmark is the opposite of what the evidence shows (Tr. Vol. 17, pp. 29-30).

In support of its recommended disallowance, SEC discusses the OEB's decision for Hydro One Distribution in EB-2013-0416 (SEC argument, para. 7.5.17). SEC's discussion omits two salient points. First, Hydro One's benchmarking showed it to be 10% above market median, compared to OPG's 5%. Second, the OEB disallowed half the difference between the forecast compensation levels and compensation at market median, not the full amount as SEC recommends (EB-2013-0416, Decision with Reasons, p. 24).

Auditor General's Report and Public Sector Salary Disclosure List

This section responds to SEC submissions on the Auditor General's Report and the Public Sector Salary Disclosure Act ("PSSDA") list. While these submissions are more in the nature of "colour commentary" rather than specific recommendations for adjustments to the revenue requirement, OPG nonetheless refutes them. They are uniformly biased and often wrong.

SEC claims that after a few years of positive trends OPG is again paying its employees too much and points to the Province's annual PSSDA list (known as the "Sunshine List") as evidence of this (SEC argument, paras. 7.5.10-7.5.12). OPG has explained that the list is based on amounts shown on employees T4 slips and thus contains all compensation paid, including base salaries, incentives, shift premiums, other allowances, and overtime paid in a given year, which may not be the year in which these sums were earned (Ex. J17.5).

SEC's main claim, that the number of employees shown as receiving $200K or $300K per year is rising well above historic levels, is completely refuted by Exhibits J17.5 and J17.7. For payments above $200K, comparing 2013 to 2016, shows that the absolute number of individuals has fallen and the number as a percentage of T4 slips issued has remained at approximately 2.6% for unionized employees and 1.3% for management employees (Ex. J17.5). For payments above $300K, comparing 2013 to 2016 shows that for unionized employees the absolute number of individuals fell while the percentage remained the same at 0.1% and for management employees both the absolute number and percentage rose slightly, from 0.3% in 2013 to 0.4% in 2016 (Ex. J17.7). OPG explained the factors that cause year over year variation (Ex. J17.5; Ex. J17.7).

SEC selectively discusses certain aspects of OPG's response to the Auditor General's report and how that response has evolved over time (SEC argument, para. 7.5.28), but the overall point it seeks to make in the context of this Application is not readily apparent. Below OPG responds to the specific aspects of the 2013 Auditor General's Report that SEC raises.

SEC claims that OPG's management employee incentive compensation results are skewed to above average performance and based on this concludes OPG's goals are set too low (SEC argument, para. 7.5.28(a)).[78] OPG rejects this claim. Review of the 2013 through 2016 scores shows that over this period, on average 70% of employees received scores that were at or below target (Ex. L-6.6-15 SEC-76, Attachment 2; Ex. J17.2). Fundamentally, SEC's criticisms on this issue, including those made in the context of the Towers methodology, are misguided (SEC argument, para. 7.5.9). They ignore the most important fact – OPG's management incentives have been and continue to be budgeted at target and were benchmarked by Towers at that level (Ex. F4-4-1, p. 4; Tr. Vol. 17, pp. 11-15). Therefore, over the IR term, customers will pay only the amounts necessary to fund incentive compensation at target levels.

AMPCO's view is that OPG should forecast management incentives based on historical performance against target (AMCPO argument, para. 224). OPG disagrees that it is possible to extrapolate future scorecard performance from past performance because certain objectives (e.g. projects) and business circumstances vary from year to year. Nonetheless, as a practical matter, OPG notes that the average corporate score for the 2013-2015 period was 0.98 compared to a target of 1.00 (Ex. JT3.1).

Regarding incentive compensation, SEC also points to an OPG audit that found compliance with the requirements for SMART (specific, measureable, achievable, relevant and realistic and time-bound) objectives for determining incentive compensation requires improvement (SEC argument, para. 7.5.28 (a)). Contrary's to SEC's claims, OPG recognizes that developing the quality of individual performance metrics is a very important area where skill levels and performance require improvement, which is why it was subject to a follow-up audit in the Fall of 2016 and remains an areas of focus (Ex. JT3.4, Attachment 9). Also contrary to SEC's submission, OPG is not targeting to achieve 70% compliance with SMART objective, but rather has set 70% as a minimum goal for 2017.[79]

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[78] SEC identifies "incentive compensation higher than forecast" as one of their concerns with the Towers methodology (SEC argument, para. 7.5.9). CME includes a similar complaint (CME argument, para. 266).
[79] Ex. J17.8 states:

> "For 2017, OPG is targeting to have greater than 70% of performance plans include at least three high quality objectives that incorporate the underlying SMART principles. This target represents an improvement over previous audit results and recognizes that the development of skills in writing objectives will be realized over time through practice and training."

SEC next claims to be troubled by OPG's decision to modify its policy regarding the rehiring of former employees (SEC argument, para. 7.5.28(b)). SEC points to the decision to reduce the waiting period before rehire from one year to six months and eliminate it for certified employees (Ex. L-6.6-1 Staff-140, Chart 1). SEC claims that this change happened "right after the Auditor General's 2015 report which gave OPG a clean bill of health on this issue," but that is incorrect.[80] As OPG explained, some of the individuals rehired are authorized nuclear operators who, as previously mentioned, require extensive training, and who lose their authorization if they cease working for any extended period (Tr. Vol. 15, pp. 172-73). More generally, OPG explained that in 2015 and 2016 it experienced higher than anticipated attrition (Ex. L-6.6-19 SEP-13). In these circumstances, former employees represent a valuable source of experienced talent who arrive fully prepared to accomplish the necessary work, on a temporary basis.

On sick leave, SEC criticizes a policy that only covers unionized employees hired before 2001 (SEC argument, para. 7.5.28(c)). OPG notes that, while collective bargaining has not produced any retroactive change to this legacy policy, the number of employees covered by it is decreasing every year (Ex. L-6.6-2 AMPCO-144). Moreover, throughout 2014 and 2015, OPG implemented initiatives to increase focus on compliance with absence management programs and improve the health culture and overall health of its workforce (Ex. L-6.6-2 AMPCO-145). OPG's annualized total sick leave days per employee continue to be lower than those of the public sector (Ex. L-6.6-2 AMPCO-144).

More generally, OPG notes that it values the feedback provided by the Auditor General, understands its responsibility to address the Auditor General's findings and, to that end, has worked diligently to implement the Auditor General's recommendations. OPG also recognizes, however, that the ultimate responsibility for safely, reliably and efficiently operating the company's generating facilities rests with OPG's management. As such, while being cognizant of Auditor General's previous concerns, OPG submits that management must be able to adjust policies to address changing business requirements, even if these policies were originally implemented in response to the Auditor General.

[80] The Auditor General's 2015 follow-up was dated December 2, 2015, while OPG made the change to its rehire policy some six months later in June 2016 (Ex. L-6.6-1 Staff-140).

Collective Bargaining and Net Zero

SEC claims, incorrectly, that the results achieved in collective bargaining do not represent "net zero" (SEC argument, para. 7.5.21). SEC cites the calculations provided in OPG's response to interrogatory Ex. L-6.6-15 SEC-72 in support of this statement (see Tr. Vol. 17, p. 81; Ex. JX17.10). This interrogatory shows only the costs and savings attributable to the nuclear business, not to OPG as a whole. These calculations were also completed at a different point in time than those submitted to Government, and use a different vintage of data to be consistent with the data and assumptions underpinning this Application. Mr. Kogan explained this in detail during SEC's cross examination, but SEC never refers to this explanation (Tr. Vol. 17, pp. 81-82 [CONFIDENTIAL]). OPG's witnesses also pointed SEC to interrogatory Ex. L-6.6-1 Staff-147 which explains the net zero calculation provided to the Government and provides the Minister's letter confirming that OPG met the net zero mandate (Ex. L-6.6-1 Staff-147, Attachment 2). They also agreed to provide SEC with the information OPG provided to the Minister of Energy (Ex. JX17.10).

SEC's argument in this section has two additional flaws. The numbers cited in SEC argument for both the PWU and Society are out-of-date because they were corrected in an updated response to interrogatory Ex. L-6.6-15 SEC-72. In particular, the amount SEC cites as a cost of the Society collective agreement is actually a savings in the updated version. During SEC's cross examination OPG witnesses made SEC counsel aware he was using the out-of-date numbers and provided SEC with the correct numbers, but SEC's argument continues to use the uncorrected numbers (Tr. Vol. 17, p. 79 [CONFIDENTIAL]).

Also in this section SEC claims that OPG negotiated provisions that will yield cost savings that benefit OPG [redacted] in exchange for items that will impose additional costs on customers [redacted] (SEC argument, para. 7.5.23 to 7.5.26). Below OPG shows paragraph by paragraph that SEC's suppositions and submissions on these points are wrong.

- Paragraph 7.5.23 – OPG did not use the reduced severance provisions that it had negotiated because PEO eliminated the need to sever employees (Tr. Vol. 17 p. 83). Thus, rather than saving money by paying reduced severance, OPG saved even more money by not having to pay any severance at all. Since the severance costs were not included in OPG's 2016-2018 Business Plan, which assumes Extended Operations (and thus are also not included in the Application), the savings from not having to pay severance were realized by customers, contrary to SEC's claim.[81]

- Paragraph 7.5.24 – SEC's whole argument in this paragraph is rooted in its continuing failure to read the corrected version of Ex. L6.6-15 SEC-72. Regarding the purchased services agreement that SEC states only applies [redacted], the corrected version states: [redacted] (Ex. L-6.6-15 SEC-72, Chart 1, Note 3). Thus the savings that SEC claims do not persist [redacted] clearly do.

- Paragraph 7.5.25 – As noted above the Society collective agreement produces a [redacted] The [redacted] appear [redacted] because the cost grow over the term of the agreement as the 1% wage increase in year one, continues into year two where the cost of the 1% increase from year one is added to cost of the 1% increase for year two.

- Paragraph 7.5.26 – SEC claims that OPG should have better managed the timing of the items it negotiated [redacted] The only way for OPG to have balanced the costs and savings as SEC suggests would have been to negotiate the present value of the three individual yearly 1% wage increases as single increase in the first year of the agreement, but having a relatively large increase in year one followed by two years of frozen wages was not considered desirable by either OPG or the unions.

Finally SEC argues that OPG's wage assumptions for the balance of the IR term beyond the expiry of the current collective agreements (March 31, 2018 for the PWU and December 31, 2018 for the Society) are unreasonable (SEC argument, para. 7.5.27). SEC assumes that none of the savings in the current agreement [redacted] As OPG witnesses explained, [redacted] (L-6.6-15 SEC-70; Tr. Vol. 17, pp. 90-96). Moreover, while it is not possible to calculate precisely how the value of these provisions may change in the future because that will depend on the business needs and conditions at the time, [redacted] (Tr. Vol. 17, pp. 91-92, 95 [CONFIDENTIAL]). OPG submits that its assumptions are reasonable based on historical experience and general trends in labour costs and its experience negotiating offsets in the past two collective agreements (Tr. Vol. 17, p. 96).

[81] OPG also notes that the calculation in SEC footnote 446 is incorrect. The savings are from lower headcount throughout the IR term (not just for 57 months), but as noted these savings already have been built into OPG's forecast.

Conclusions on Benchmarking

SEC argues that in the next Application, OPG should provide all inclusive benchmarking study that consist of all elements of the "compensation package, e.g. base salary, incentive pay, lump sum payment, share grant value, and the value of pensions and existing and future benefits." (SEC argument, para. 7.5.37). AMPCO echoes SEC's submissions and would also include overtime (AMPCO argument, para. 240). All inclusive benchmarking in the form envisioned by these parties is not industry standard practice. OPG is not aware of, and parties have not pointed to, any examples of this type of benchmarking, either in the context of OEB regulatory proceedings, or elsewhere. As explained above for the lump sum payment, overtime and share grants, and below for pensions and benefits, OPG does not believe that this type of benchmarking would yield meaningful comparisons and is unsure how such a study would be performed. While OPG has every intention of continuing to benchmark compensation, pensions and benefits, for future payment amounts proceedings and for internal purposes, OPG respectfully requests that the OEB decline to order the type of benchmarking sought by SEC and AMPCO.

7.7.3 Pension and Benefits

Introduction

As OEB staff acknowledge, this Application clearly demonstrates improvements to the employee contribution ratio for pensions as well as improvements in the salary basis for determining future pension benefits and the retirement eligibility formula (OEB staff argument, p. 109; Ex. F4-3-1, pp. 15-16). For represented employees, these improvements were only achieved during the last round of collective bargaining with the assistance of the Government. OPG has implemented similar changes for management employees.

It is equally indisputable that further progress is required if OPG is to achieve the Government of Ontario's goal of equalizing employee and employer current service pension contributions for single-employer pension plans, as discussed below. Continued effort also will be required to make other reductions in OPG's cost of providing pensions and benefits in future rounds of collective bargaining (L-6.6-1 Staff-147(h)). OPG is committed to this effort while recognizing that continuing to make strides in this area will necessarily take time, and engagement with its unions. In addition, OPG notes that if the proposed pension costs are approved as filed and further improvements in this area are achieved in future rounds of collective bargaining, any resulting savings would be credited to ratepayers through the operation of the approved pension and other post employment benefits (“OPEB”) D&V accounts (Tr. Vol. 16, p. 17, lines 10-14).

The Towers benchmarking shows that the value of OPG’s pension and benefits for a typical plan participant is above market (Ex. F4-3-1, Attachment 1, p. 27). However, as Towers explained, it is not possible to directly translate the value differences shown in the pension and benefits benchmarking to costs (Ex. J16.5). Costs depend on a number of variables specific to each company, which are difficult to track and compare. These variables include, among other things, pension fund investment performance; actuarial assumptions about future salary growth, mortality, and benefit usage; demographics; and employees’ choice of flexible benefits (Ex. J16.5).

OEB staff and SEC reviewed the results of various pension and benefits benchmarking studies that OPG has undertaken in recent years (OEB staff argument, pp. 108-109; SEC argument para. 7.5.30). Many of the specifics from these studies and related interrogatories are confidential. As OPG does not dispute the figures cited by OEB staff and SEC, OPG will not repeat the confidential material here in order to avoid the need for further redactions.

OPG respectfully submits that the OEB’s review should consider the question of whether, in the context of what OPG has achieved and what was practically achievable, the proposed pension and benefits costs are reasonable. OPG submits that they are. OEB staff acknowledge that some progress has been made; however, their recommended compensation disallowance of $50M per year is based primarily on the view that the requested pension and benefits costs are excessive. SEC claims that OPG’s pension and benefits cost should be reduced by $40M annually (as part of a total compensation disallowance of at least $86.7M), using arguments largely the same as those advanced by OEB staff (SEC argument para. 7.5.36). AMPCO recommends a disallowance of $38.3M per year for these costs (as part of a total compensation disallowance of $85M), while CME advocates for an implicit disallowance of up to $33.3M per year (as part of a total compensation disallowance of up to $80M), for similar reasons (AMPCO argument, para. 246, CME argument, para. 279). CCC supports the non-confidential arguments of OEB staff and SEC on pensions and benefits without recommending a specific disallowance (CCC argument, p. 22). Below OPG responds to parties' submissions on these issues. Discussion of the implications of the OEB's recently issued Board Report in the generic proceeding on pension and other post-employment benefit costs (EB-2015-0040) is found in Issue 9.6 (Section 10.6).

Contribution Ratio

OEB staff and SEC express concerns about the method that OPG has used to calculate the employee to employer ratio for pension contributions and suggest OPG is overstating the portion of the contributions made by its employees (OEB staff argument, pp. 109-111; SEC argument para. 7.5.34). This is both incorrect and somewhat surprising given that the OEB staff and SEC cite to the *Report on the Sustainability of Electricity Sector Pension Plans* ("the Leech Report") throughout their submission (OEB staff argument, pp. 107 109-110; SEC argument, footnote 468).

The Leech Report discusses "equal cost-sharing <u>for ongoing contributions</u>" in a number of places (Leech Report, p. 2 (emphasis added)). The Leach Report calculates an employer/employee contribution ratio of 76% / 24% for OPG, or approximately 3 to 1 (Leech Report, Appendix B, Table 2).[82] That calculation shows the percentage paid by the employer and the employees, respectively, of the current service pension costs. This is precisely how OPG calculated the ratios shown in its evidence at Ex. F4-3-1, Figure 10, (at p. 16). There, OPG shows the 2014 ratio of 3 to 1 moving to about 2 to 1 by 2017. When the Leach Report speaks of the ratio moving to 1 to 1 over time, this is the ratio, calculated exactly as shown, to which the report refers.

That the Leach Report uses the current service cost ratio when discussing equalizing employer and employee contributions is to be expected because that was the Government's specific direction. The 2012 Ontario Budget includes the Government's statement that "single-employer public-sector pension plans will move to a 50–50 cost sharing formula <u>for ongoing contributions</u> within five years" (2012 Ontario Budget, p. 271 (emphasis added)).

[82] Using the numbers in Appendix B, Table 2 of the Leach Report for OPG, the calculation of the employee percentage is: 73 / (73+225) = 24%.

The method used to calculate the employer to employee contribution ratio is important because achieving a target contribution ratio of 1 to 1 for current service pension remains Government policy. Thus, while OEB staff may find it useful to calculate different ratios to illustrate particular points, these alternative ratios should not be confused with the specific mandate established by the Government for single-employer pension plans like OPG. Moreover, these alternative ratios are inconsistent with the way industry, the actuarial community and other experts express contribution ratios (Tr. Vol. 16, pp. 104, 107-198).

Pension Plan Sustainability

OEB staff reference the 2014 Leech Report and a 2011 internal OPG briefing document, commissioned by OPG management and prepared with the assistance of external consultants, as background for their conclusion that pension and benefits costs are excessive. These documents were developed prior to the improvements OPG made in the most recent round of collective bargaining and were addressed in some detail in EB-2013-0321. When OEB staff put these documents to OPG witnesses in this proceeding, the witnesses explained that OPG has made clear progress against a number of the metrics shown and that the risks related to pension sustainability are substantially less today (Tr. Vol. 16, p.84, line 17 to p. 86, line 9). OEB staff's submissions acknowledge OPG's testimony that the sustainability of its pension plan has materially improved (OEB staff argument, p.108). A comparison of the cost levels (both on a cash and accrual bases) requested in this proceeding to those requested in EB-2013-0321, reflect the improvements in this area.[83]

The Recommended Disallowances Are Excessive

OEB staff's recommended disallowance of $50M per year in compensation costs appears to be tied primarily to the results of the pension and benefits benchmarking, as the OEB staff acknowledge that total direct compensation is "close to or marginally above" market (OEB staff argument, p. 112). This amount appears to be quite high, representing approximately 15% of

[83] Comparing the pension cost shown in OEB staff argument, Table 26 (p. 106) with those shown in EB-2013-0321 Decision with Reason, Table 21 (p. 84).

OPG's pension and OPEB costs, using the cash amounts for pension and OPEB that OPG has included in its nuclear revenue requirement request.[84]

OEB staff state that their proposed disallowance in this Application is less than the EB-2013-0321 annual disallowance amount of $100M (OEB staff argument, pp. 102, 113). OPG believes that this statement does not consider the full amount of OM&A disallowance proposed by OEB staff in their submissions. In EB-2013-0321, the OEB reduced OPG's total OM&A by $100M per year citing a number of OM&A-related factors predominately involving compensation and benefits, and staffing levels (EB-2013-0321 Decision with Reasons, pp. 80-82). This disallowance covered both hydroelectric and nuclear OM&A. The amount allocated to Nuclear annually was approximately $88M (EB-2013-0321 Payment Amounts Order, Appendix A, Table 3a, Note 4). In this proceeding, in contrast, OEB staff propose to disallow about $135M annually of nuclear OM&A expenses, not including the proposed deferral of Extended Operations costs, as shown in Chart 7.2 below.

Chart 7.2
OEB Staff Proposed Nuclear OM&A Disallowances

OEB staff Proposed Annual Nuclear OM&A Reductions*	Annual Amount ($M)
Compensation and Benefits	50.0
Base OM&A (Other Purchased Services)	25.0
Base OM&A (Labour & Overtime)	15.0
Outage OM&A (average value of 5% reduction per year)	19.1
Corporate Support OM&A (five-year total = $40.6M)	8.1
Increased Nuclear Stretch Factor (five-year total = $70.4M)**	14.3
Including Outage and Project OM&A in the Stretch Factor (five-year total = $21.3M)**	4.1
Total	**135.6**

*This Chart shows only recommended disallowances and does not include the proposed deferral of PEO costs.
** Based on OPG's update of Table 40 in OEB staff argument (see Issue 11.3, Section 12.5).

As OEB staff recognize, OM&A costs are largely comprised of labour (OEB staff argument, p. 99). Thus, while OEB staff justify some of the proposed disallowances shown in Chart 7.2 above on bases other than compensation and benefits, the fact remains, as the OEB's decision in EB-2013-0321 recognized, whether a disallowance is attributed primarily to compensation or

[84] On an accrual basis, the OEB staff proposed disallowance would represent approximately 14% of the nuclear pension and OPEB costs.

compensation and other factors, does not change the fundamental fact that OPG has less money available to fund required nuclear OM&A.

In OPG's submission, in light of the progress that the company has made in negotiating and implementing higher employee contributions and more favourable terms for pension benefit calculation and eligibility, a 15% disallowance as proposed by OEB Staff is unwarranted. Other parties' proposed total compensation disallowances are even higher: $80M (CME); $85M (AMPCO); and, at least, $86.7M (SEC). These total disallowances are unreasonable in light of the progress made since the last proceeding and, particularly so, given that they are in addition to parties' proposals disallowing other nuclear OM&A costs that are largely comprised of labour.

7.8 Issue 6.7

Oral Hearing: Are the corporate costs allocated to the nuclear business appropriate?

Based primarily on historical spending, OEB staff recommend annual disallowances ranging from $3.2M to $20.1M, for a total IR term reduction of $40.5M (OEB staff argument, pp. 114-116). CCC did not calculate a specific reduction, but would limit OPG to an annual inflationary increase using actual 2016 spending as a starting point (CCC argument, p. 22). SEC would reduce the forecast amounts by 2.5% per year for a total disallowance of $55.7M over the period (SEC argument, para 7.6.7). LPMA adopts SEC's proposed 2.5% annual reduction for 2018-2021, but would impose a greater reduction in 2017 for a total disallowance of $60.8M (LPMA argument, p. 18). CME proposes a reduction for Executive and Corporate Services ("ECS") costs and, to a smaller extent Finance costs, based on benchmarking results, and also supports SEC's proposal.

OEB staff and parties' submissions involve three issues, the appropriateness of the Hackett benchmarking, the level of ECS and Finance costs and OPG's historical spending trend. Below OPG discusses these issues and demonstrates why the proposed disallowances should be rejected.

Benchmarking

With regard to the Hackett Benchmarking, OEB staff appear to question the reliability of the IT benchmarking, where OPG was found to be in the first quartile. In contrast, OEB staff do not raise any concerns with the reliability of the results in other areas of Hackett Benchmarking where OPG's performance was at median or below. The primary area of OEB staff's concerns about IT benchmarking appears to be with the number of IT end users.

Hackett defined an end user as follows:

> End User: An individual (typically either an employee or contractor) that spends at least 10% of his or her time using a company provided, funded, supported computing device that is part of the company's IT infrastructure (i.e. desktops, laptops, hand held devices, etc.) to support his or her business function. The user must have direct access to internal applications / systems to execute specific transactions on behalf of the company. OPG includes end users associated with regulated operations only. (Ex. F3-1-1, Attachment 1, p. 6).

OEB staff suggests that "it is not clear whether "doing at least 10 percent of efforts using and accessing systems" is a consistent definition applied to all peers." OPG has carefully reviewed the record and is unable to locate any support for such a statement and, in fact, confirms that this definition is part of Hackett's Benchmarking approach and has been consistently applied to all peers. Furthermore, there is no reason to believe that this definition produces an unreasonably high number of end users at OPG, in comparison to the peers.

As Mr. Mauti testified, while all regular OPG employees have LAN IDs, so do numerous temporary employees and contractors whose work requires them to access OPG's IT system (Tr. Vol. 20, pp.18-21). The fact that the number of end users grew between 2010 and 2014, while the number of employees declined, is not surprising (Ex. F3-1-1, Attachment 1, p. 6). As Mr. Mauti explained at the Technical Conference, the increasing number of IT end-users between 2010 and 2014 can be attributed to the growing number of contractors for DRP and outage work, combined with greater digitalization of tasks such that more people require access to OPG IT systems to accomplish their work (Tr. Tech. Conf. Vol. 2, pp. 210-211).

Executive and Corporate Services and Finance Costs

While OPG's ECS costs as a percentage of revenue declined by 19% between 2010 and 2014, they remain higher than the comparators (Ex F3-1-1, Attachment 1, p.15). CME proposes a disallowance of $100M for ECS costs based on the results of the benchmarking (CME argument, para 220). OEB staff state that cross examination responses and Undertaking J20.3 indicate that OPG has no plans to target improvements in ECS costs, but that is not the case. The main point that Mr. Mauti actually made in the exchange with OEB staff is as follows:

> I think there are specific drivers, especially on those categories that had been flagged by Hackett, environment, and health and safety specifically. I don't think you can discount the fact that operating a nuclear generating fleet and the level of reporting and requirements for nuclear safety, public safety, and environmental impacts, the testing that we do and the monitoring that we do, not only as a result of CNSC regulations, but just to be able to operate in the communities that we do and to gain their trust and the public trust, we do have to expend an amount for those functions, and that is the largest of the ECS categories that was listed on that table that you had on [Ex. F3-1-1, Attachment 1] page 13, I believe it was.
>
> MR. MILLAR: Yes.
>
> MR. MAUTI: So being the largest cost category, that one very specifically, I think if I was a ratepayer I would want to make sure that OPG was properly protecting the environment and ensuring public and employee safety, so I think there has to be an understanding and appreciation for a nuclear generating fleet that some of these things will result necessarily in higher than the median for the group of companies that we look at, especially since only five of the 19 are nuclear generators, and as I mentioned yesterday, of those five I don't believe any are as highly dependent and focused on nuclear as OPG would be in terms of its overall corporate structure, so I think that would have to be taken into account. (Tr. Vol. 21, pp. 126-127).

As Mr. Mauti's testimony discussed, however, a number of other ECS areas (i.e. Risk Management, Environment, Health and Safety) exist, among other things, to ensure that OPG operates its nuclear and regulated hydroelectric facilities with a clear commitment to public and workplace safety, environmental stewardship and robust risk management practices. These values are fundamental to maintaining OPG's social licence to continue as an operator of facilities that have a significant footprint in communities across the Province. On this basis alone, CME's proposed disallowance is unreasonable.

In Undertaking J20.3, OPG responded to a request to show the cost consequences if the finance and ECS functions, which benchmark above median, were brought to the 2014 median level.[85] In its response, OPG provided this information for each of the four benchmarked corporate support services functions (i.e., OPG added lines for the HR and IT function). The Undertaking response shows that, notwithstanding the performance of the ECS function, if all of these corporate services functions were brought to 2014 median levels, aggregate costs would be higher by $95M (or an average of $19M per year) over the IR term. Furthermore, as CME acknowledges, at least for ECS costs, the use of a static 2014 median does not reflect inflationary pressures that peers are likely to have experienced over the period (CME argument, para. 220). Finally, as these costs are largely comprised of labour, any disallowance here would overlap substantially with the disallowances proposed in compensation and benefits.

In addition to ECS costs, CME makes a submission for a disallowance of Finance costs of $19M over the IR term, representing the amount by which Undertaking J20.3 calculates the costs would be over the 2014 benchmark (CME argument, para. 210). OPG notes that while CME's proposed ECS reduction recognizes the static 2014 median issue noted above, the proposed disallowance for Finance costs contains no such recognition, which would drastically reduce, if not completely eliminate, the proposed reduction.

OPG understands that there are areas within ECS where the Hackett Benchmarking highlights opportunities for improvement and fully expects to continue to challenge itself, through future business planning processes, to seek out additional cost reductions. OPG also notes that this is exactly the behavior that the stretch factor component of the Custom IR, which under OPG's proposal would apply to corporate support costs, is intended to drive.

OPG's Historical Spending Trend

OEB staff's argument reviews the historical growth of corporate services costs and states that this review demonstrates that the proposed levels of IR term costs are unreasonable. CCC, LMPA and SEC focus their arguments on the variances between forecast and actual levels of corporate support services costs over the 2014-2016 period. Based on their review, OEB staff and CCC propose that a formulaic increase replace OPG's 2017-2021 planned costs, SEC proposes a 2.5% disallowance of each year's costs over the period, and LPMA adopts elements

[85] OEB staff writes: "If OPG's corporate wide ECS costs had been at median in 2014, expenses would have been reduced by $81 million" (OEB staff argument, p. 114). This figure is significantly higher than those shown in Undertaking J20.3 because it is an OPG-wide figure whereas the amounts in J20.3 are nuclear only.

of both proposals. OPG has three responses. First, parties' submissions ignores the legitimate reasons that OPG has provided to explain the proposed costs increase are necessary, as further discussed below. Second, OEB staff's selection of 2014 as a base year is arbitrary and the use of a 1% growth rate is unreasonable. Third, an approach of mechanistically applying a formula to a historical year is inconsistent with the OEB's guidance on reviewing Custom IR applications.

OPG has explained some of the factors that account for the necessary growth in corporate support OM&A expenses attributed to the nuclear operations, but these do not appear to have been considered in developing parties' recommendations. For example, the single largest driver for the observed increase between 2015 actual and 2016 budget was the assumption that starting April 1, 2016, OPG's 700 University Avenue property would be sold and the asset service fee that OPG's regulated operations had been incurring would be converted to an OM&A lease payment (Ex. F3-2-1, p. 5). This caused a substantial increase in Real Estate costs that was largely offset by a reduction in the asset service fee (Ex. L-6.7-1 Staff-166; Tr. Tech. Conf. Vol. 3, pp. 5-6). The resulting increase in Real Estate costs above 2015 was projected to be about $6M in 2016 and about $8M annually in 2017-2021 (Tr. Vol. 20, p. 38).

As the property was not sold in 2016, Real Estate costs in 2016 were notably lower than budgeted (Tr. Vol. 20, pp. 35-36). The delay in selling 700 University Avenue is the single largest driver of the under-spending in 2016 corporate support costs observed by parties (OEB staff argument, p. 116; CCC argument, p. 22; SEC argument, para. 7.6.2). Correspondingly, the actual asset service fee charged to the Nuclear operations in 2016 was higher than budgeted (Ex. J14.2, Attachment 1). OPG notes that, if the 2016 value produced by OEB staff's approach is adjusted by $8M per year to account for the lease costs that are otherwise not considered in OEB staff's proposal, which uses 2014 actual costs as a base, then OEB staff's proposed corporate support cost levels would total within $1M of OPG's requested levels over the five years, even at OEB staff's proposed 1% per year escalation, which is well below anticipated inflation.

There are two other aspects of corporate support costs where OEB staff's observations are inaccurate. First, OEB staff state that they would have expected People and Culture expenses to be lower in 2021 than in 2014 because of lower forecast FTEs (OEB staff argument, p. 116).

As OEB staff acknowledge, the increase over this seven year period is small, from $98.2M to $100.5M. OPG notes that the human resource cost structure is not completely variable with FTEs and that OEB staff's observation does not consider seven years of inflationary pressures. Even assuming OEB staff's unreasonably low 1% per year escalation allowance, discussed below, the 2021 forecast costs would be lower in real terms than the 2014 costs.

Second, OEB staff cite a 7.9% compound annual growth rate for Corporate Centre costs for the 2014 to 2021 period, which it characterizes as "well above inflation" (OEB staff argument p. 116). As OEB staff correctly note, this increase is mainly related to the transfer of staff from other areas, such as Finance. The transfer of the Assurance Group from Finance to the Corporate Centre is the predominant driver of the Corporate Centre cost increase (Ex. L 6.7-1 Staff 167). Thus, the compounded annual growth rate calculated by OEB staff is incomplete as it looks only at the increase in the Corporate Centre while ignoring the related decrease in the Finance costs, which fall between 2014 and 2015 (Ex. F3-1-1, Table 3).

OEB staff and other parties do not explain why the specifics of their proposed formulaic adjustment are appropriate. In particular, OEB staff propose to escalate costs from 2014 actual figures without explaining why a historical spending from three years ago is the appropriate starting point. Similarly, in an era where general inflation is consistently around 2%, OEB staff offer no justification why the 2014 starting point should escalate by only 1%. This figure is particularly low given that corporate support costs will be subject to the stretch factor, which will further reduce the approved amounts by 0.3% annually under OPG proposal or 0.6% annually under OEB staff's proposal. OPG submits that a 0.7% per year or 0.4% per year net increase in corporate support services costs is not reasonable, even assuming future efficiency savings under Custom IR.

Finally, suggestions by OEB staff, CCC, SEC and LPMA that the OEB ignore OPG's forecasted corporate support costs and use a formulaic adjustment instead, goes against the OEB's guidance on Custom IR applications. As the OEB has observed: "A Custom IR, unlike other rate setting options in the RRFE, does not include a predetermined formulaic approach to annual rate adjustments,…" (EB-2014-0116, Decision and Order, p. 5). OPG submits that it has provided a challenging forecast of corporate support spending in each year of the IR term, which it proposes to reduce by the approved nuclear stretch. On this basis, the parties' proposed disallowances should be rejected.

7.9 Issue 6.8

Oral Hearing: Are the centrally held costs allocated to the nuclear business appropriate?

No party opposed OPG's position on this issue. OPG submits, as it did in its AIC (AIC, Section 7.9), that the centrally held costs allocated to the nuclear business are appropriate and should be approved.

7.10 Depreciation

7.11 Issue 6.9

Primary: Is the proposed test period nuclear depreciation expense appropriate?

OPG set out its proposal on depreciation in Ex. F4-1-1 and in section 7.10 in its AIC (AIC, pp. 121-124). OEB staff supports OPG's proposal in section 6.9 of its submissions (OEB argument, pp. 118-119). Specifically. OEB staff:

- Take no issue with OPG's proposal regarding the Pickering extension (OPG has chosen not to incorporate the extension for depreciation purposes, requesting a D&V account to capture the impact of an end of life ("EOL") date revision should it occur). OEB staff also take no issue with OPG's revised EOL dates for the prescribed Pickering facilities. (*Id*.)
- Support OPG's proposal to request an accounting order should the criteria as indicated by OPG be met. OEB staff note the methodology has been approved in past decisions from the OEB. (OEB argument, p. 119)
- Take no issue with OPG's proposal 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. OEB staff notes that OPG's Depreciation Review Committee 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 D&V account should there be a material change in service life, is sufficient to delay the performance of an independent review of service lives, which would be conducted in 2021, after Darlington Unit 2 is returned to service, based on year-end 2020 asset net book values. (*Id*.)

The only other intervenor to make submissions on issue 6.9 is LPMA, who (along with OEB staff) requested that additional evidence be filed regarding OPG's depreciation expense (LPMA argument, p. 19). These submissions are addressed in section 5.4.

OPG received no other submissions on this issue and submits that the OEB should find that OPG's nuclear depreciation expense is appropriate.

7.12 Income and Property Taxes

7.13 Issue 6.10

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

OEB staff and LPMA are the only parties to make submissions on this issue. OEB staff are largely supportive of the total tax amounts OPG has proposed to include in the nuclear revenue requirement but provide a number of submissions on the treatment of Scientific Research and Experimental Development Investment Tax Credits ("SR&ED ITCs" or "ITCs"). The proposed regulatory income taxes for the nuclear business, net of the ITCs, total $10.7M over the 2017-2021 period, as shown in OEB staff's Table 30. The proposed income tax amounts reflect a forecast of SR&ED ITCs totaling $92.0M over the period, based on OPG's 2016-2018 Business Plan, as shown in OEB staff's Table 32.[86] From 2017-2019 and 2021 the proposed income tax amounts are negative due to the application of the ITCs.

LPMA supports OEB staff's submissions regarding SR&ED ITCs. LPMA additionally submits that the increase in OPG's property taxes is not justified.

These issues are addressed, in turn, below.

7.13.1 SR&ED ITCs

Broadly speaking, OEB staff are concerned that ratepayers will not receive the appropriate amount of SR&ED ITC benefits as a result of differences between forecast ITCs included in the nuclear revenue requirement and the actual ITCs earned by the nuclear business. OEB staff propose to prospectively implement certain true-up mechanisms, as well as to increase the forecast 2017-2021 nuclear ITCs by a total of $40.5M to reflect the more recent forecast per OPG's 2017-2019 Business Plan.[87] OPG understands that the OEB staff propose both the

[86] Historically, virtually all of SR&ED ITCs from OPG's regulated business have been from the nuclear operations (e.g., see Ex. JT3.13, Chart 1).
[87] As explained in Ex. F4-2-1, section 3.4 and L-6.10-1 Staff-189 (e), SR&ED ITCs are taxable. As such an increase in ITCs of $40.5M over the 2017-2021 period would increase regulatory taxable income, resulting in additional

following with respect to true-up mechanisms: (i) prospectively, a carryforward mechanism[88] for the ITCs earned by the nuclear business in a given year, to the extent there are insufficient regulatory income taxes for the nuclear business to fully utilize those ITCs in that year, and (ii) prospectively, expand the scope of the Income and Other Taxes Variance Account to capture the difference between actual and forecast nuclear ITCs. OEB Staff also assert, with respect to the 2014-2016 period, that "if OPG had carried forward the nuclear ITCs, the benefits would flow to rate payers in this application as the ITCs would be used against in the test period to reduce the cumulative nuclear taxes OPG is forecasting over the 2017 to 2021 period" (OEB staff argument, p. 121). Below, OPG responds to each of these submissions.

7.13.2 Forecasting Approach and Updates

To determine the actual amount of ITCs earned in a given year, OPG engages external specialists to undertake a review of the company's expenditures to identify qualifying work and prepare the SR&ED ITC claim, as part of the corporate tax return. The preparation of the SR&ED claim takes several months and involves detailed technical interviews and reviews of documentation. The actual ITCs are therefore a function of specific elements of work undertaken as part of various work programs and projects during the year that external expert consultants determine to be eligible under the SR&ED ITC program. Therefore, actual ITCs will vary from year to year.

The external consultants review the projects completed (or in progress) for a given year after the end of that year. They apply the benefit of hindsight in order to determine which work qualifies for the SR&ED claim. It is not possible to forecast ITCs with the same high level of precision in advance of the year-end, let alone as part of a multi-year business plan. Recognizing this, OPG forecasts ITCs based on the aggregate actual ITCs per the latest tax return available at the time the forecast is prepared and, for certain projects considered to be outside of ongoing work programs, a high-level forward-looking estimate provided by technical personnel (Ex. L-6.10-1 Staff-189 (c)). OPG has been applying this methodology consistently, including for the 2013-2015 forecast ITCs in EB-2013-0321 and the 2017-2021 forecast ITCs in this Application. OPG submits that this forecasting methodology is reasonable, and the

regulatory income taxes of approximately $8.7M. Therefore, the net reduction of regulatory income taxes over the period (before tax gross-up) would be $31.8M, not $40.5M.

[88] In accordance with tax legislation, SR&ED ITCs can be carried forward for a period of up to 10 years.

magnitude or direction of historical variances between actual and forecast amounts is not predictive of potential future variances.

It has not been the OEB's approach to true up tax amounts recovered by utilities for tax driven and operations driven factors, with the exception of items generally beyond the utility's control such as changes in tax rates, rules and assessing practices of tax authorities, and re-assessments for past periods.[89] The majority of variances in SR&ED ITCs do not fall into these categories. However, OPG acknowledges that the overall magnitude of and difficulty in forecasting the nuclear ITCs may warrant their treatment as an exception to this policy, as implied by OEB staff. Therefore, OPG does not object to prospectively truing up the nuclear ITCs (and associated taxes payable on the ITCs) to actual amounts using a variance account approach as discussed in Section 7.13.4 below. As discussed in Section 7.13.3 below, OPG does not support a carryforward mechanism as a true up approach and notes that implementing both a variance account approach and a carryforward mechanism would result in double counting of ITC benefits.

OPG does not support OEB staff's proposal to adjust the revenue requirement for SR&ED ITCs based on the 2017-2019 Business Plan. OPG has applied a reasonable, consistent forecasting methodology that appropriately reflected information regarding actual ITCs available at the time of the prefiled evidence. The potential subsequent update to the ITC forecast based on the 2017-2019 Business Plan was considered as part of OPG's comprehensive Ex. N1 Impact Statement, which was prepared with reference to a materiality threshold of $10M per year. As OEB staff note at p. 124 of their submission, the change in the nuclear ITCs was below $10M/year and therefore was not included in the Ex. N1 Impact Statement. Adjusting the revenue requirement for the updated ITCs, but no other items below the $10M threshold, would be arbitrary and selective, particularly as some of the other items below the threshold would have increased the revenue requirement. Further, if a variance account approach is adopted, the actual amount of nuclear ITCs would flow through to ratepayers regardless of the forecast amount used, rendering the update unnecessary in any event.

[89] See Section 7.13.4 for a discussion of the OEB's approach to true-ups for taxes in RP-2004-0188, the 2006 Electricity Distribution Rate Handbook.

7.13.3 Carryforward Mechanism

OEB Staff propose a carryforward mechanism for the ITCs. While OPG does not dispute OEB staff's assertion that the utilization of actual ITCs for regulatory purposes does not need to align with corporate tax return purposes and that ITCs are attributable to a particular business segment (OEB staff argument, p. 120-121), OPG submits that a carryforward mechanism nevertheless poses a number of substantive and practical challenges and is unnecessary in light of the variance account option. A carryforward mechanism would not consistently yield a full true up outcome, is likely to result in double counting of ITCs across periods, and will add unnecessary complexity. Moreover, applying OEB staff's proposed carryforward approach would likely decrease the amount of ITCs available to reduce the 2017-2021 nuclear revenue requirement.

The carryforward approach would not consistently produce a full true up outcome because the true up under a carryforward approach would depend on the level of regulatory taxable income attributed to the nuclear business in a given historical year. For example, if actual ITCs earned in given year exceed the forecast amount, but the actual regulatory taxes are sufficient to utilize all of the actual ITCs, no ITCs would be carried forward and no true up would occur. The situation may be further complicated when several consecutive historical years are involved before the next rate-setting period. For example, a portion of actual ITCs may be carried forward from historical Year 1 to historical Year 2 based on Year 1's taxable income position, but there may be sufficient actual regulatory taxes in Year 2 to utilize both the actual ITCs carried forward from Year 1 and the actual ITCs earned in Year 2, resulting in no true up. Various other scenarios can be envisioned where the amount of ITCs carried forward to a future rate-setting year would produce different, unpredictable true up results depending on the levels of actual ITCs and actual regulatory taxes, particularly over a multi-year period.

Achieving an appropriate true up effect under a carryforward approach would be further complicated by the need to take into account that a certain forecast of ITCs would have been factored into the payment amounts. For example, if a tax loss position occurs in a given historical year and the full amount of actual ITCs is carried forward to a future rate-setting year, the carried forward amount would double count the portion of any forecast ITCs already factored into the payment amounts in effect during that year.

The scenarios above demonstrate that, absent further adjustments, the carryforward approach will have limited effectiveness as a true-up mechanism, potentially shortchanging ratepayers or inappropriately double counting the ITCs benefit. And while it is possible to modify the carryforward amounts with adjustments that would ensure a full true up does occur, this would constitute a deviation from tax carryforward principles, require added tracking and reconciliation and, in any event, would yield the same effect as a simple comparison of actual ITCs to forecast ITCs – exactly what a variance account would do as a matter of course.

In addition, under the carryforward approach proposed by OEB staff, ratepayers would no longer benefit from negative income taxes on account of the ITCs as part of a revenue requirement determination. This is because OPG has been applying forecast ITCs as a reduction to the year's revenue requirement irrespective of the calculated nuclear taxable income (or loss) in that year, rather than carrying them forward. For example, this was the case for 2014 and 2015 in the EB-2013-0321 Payment Amounts Order.[90] Under OEB staff's proposal, test year ITCs would have to be carried forward to a later period if they would otherwise reduce test year forecast regulatory taxes to below zero. While it appears to OPG that OEB staff believe that this would not affect the total amount of OPG's proposed income tax amounts over the 2017-2021 period (as set out in OEB staff's Table 30), this likely would not hold true if the OEB makes revenue requirement adjustments that consequently reduce regulatory taxable income relative to OPG's proposal.[91] For example, OEB staff's proposal under Issues 7.2 and 8.2 to reflect post-Ex. N1 Impact Statement changes to the nuclear liabilities revenue requirement impact – rather than flow them through the Nuclear Liability Deferral Account and the Bruce Lease Net Revenues Account – would reduce nuclear regulatory income taxes from the currently proposed levels such that the full amount of forecast ITCs of $92.0M for the 2017-2021 period would be carried forward under OEB staff's proposal (as opposed to being credited to ratepayers in the revenue requirement). Moreover, there would be uncertainty around the future period(s) in which these carried forward amounts are ultimately utilized because, under current assumptions, the nuclear business may continue to

[90] Negative income taxes of $9.4M per year were included in the approved nuclear revenue requirement in EB-2013-0321 representing a forecast of SR&ED ITCs for the nuclear business (EB-2013-0321, Payment Amounts Order, Appendix A, Table 3, line 23).
[91] Assuming OPG's revenue requirement is approved as proposed, OEB staff's carryforward approach means that negative income taxes proposed for 2017-2019 and 2021 on account of the ITCs would need to be adjusted to zero, with the ITCs giving rise to these negative income taxes carried to reduce the proposed 2020 income taxes. OEB staff's summary of revenue requirement impacts at p. 3 of their submission omits this inter-period adjustment.

have relatively low taxable income levels for at least several years past 2021, in light of future capital cost allowance deductions related to DRP expenditures. As such, a carryforward approach very likely will delay the crediting of ratepayers with the benefit of the ITCs.

Finally, adopting a carryforward mechanism <u>together</u> with a variance account is not appropriate because it would result in a double counting of ITCs. For example, if actual ITCs are higher than the forecast amount, the difference between the actual and forecast amounts would be recorded in a variance account as a credit to ratepayers. If a portion of the actual ITCs in the year is <u>also</u> carried forward to a future rate-setting period because they cannot be utilized in that year, the carried forward amount would be double counted with the variance account amount. This is an inappropriate outcome.

7.13.4 Variance Account Approach

A variance account tracking the difference between actual and forecast SR&ED ITCs (and associated taxes payable on the ITCs) for the nuclear business is a simpler, more effective and more transparent true-up method than a carryforward mechanism. Among other things, the variance account approach will ensure that ratepayers receive the benefit of ITCs sooner than under a stand-alone nuclear carryforward approach, as it is not dependent on future levels of nuclear regulatory taxes and therefore does not restrict forecast ITCs from being credited to ratepayers through negative nuclear income taxes.[92,93]

OPG submits that a new account would need to be established to implement a variance account true up approach, as of the effective date of the payment amounts determined in this proceeding.[94] OEB staff's proposal to prospectively amend the scope of the Income and Other

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[92] While OPG acknowledges that not following the carryforward approach represents a divergence from the strict application of income tax rules, OPG feels this divergence would best meet regulatory objectives in this case, including fairness in the determination of the ITCs credited to ratepayers, consistency of true-up outcomes, and overall simplicity. As OEB staff note at pp.120-121 of their submission, while regulatory income taxes generally simulate a utility's actual corporate taxes, the two are not necessarily identical and may diverge for certain specific elements.

[93] If the variance account approach is adopted, OPG expects it would simplify its regulatory reporting of actual ITCs for each regulated business in a given year to the amount of ITCs earned by that business (subject to the applicable accounting recognition percentage as discussed at Ex. F4-2-1, pp. 10-11).

[94] The new variance account would record the difference between actual SR&ED ITCs earned at the applicable accounting recognition percentage (see Ex. F4-2-1, pp. 10-11) and the forecast ITCs included in the payment amounts. OPG expects that the new account, rather than the Income and Other Taxes Variance Account, also would capture any subsequent adjustments to the amount of actual ITCs recognized as a result of tax audit resolution or similar.

Taxes Variance Account to include a true-up to the actual ITCs earned would not only be inconsistent with the OEB-approved Settlement Agreement in this proceeding, but also inconsistent with the intent of the account and related OEB policy.

The Income and Other Taxes Variance Account was originally approved in EB-2007-0905 and has been continued in every applicable OPG proceeding since that time without change. Specifically, in approving the Income and Other Taxes Variance Account in EB-2007-0905, the OEB stated the following in its Decision with Reasons:

> The Board approves the variance account to track variations in municipal property taxes, and variations in payments in lieu of capital taxes, property taxes, and income taxes. The Board has authorized a tax variance account for electricity distributors (Account 1592, which deals with tax variances after April 2006) that is used to record variations due to changes in tax rates or rules, new assessing or administrative practices of tax authorities, and tax re-assessments for past periods. The events and circumstances that give rise to entries into Account 1592 are essentially the same as those proposed by OPG, except that OPG includes court decisions for other taxpayers that will affect OPG's tax position. The Board finds that OPG's inclusion of variations due to court decisions for other taxpayers is appropriate. (EB-2007-0905, Decision with Reasons, pp. 127-128 (emphasis added)).

The 2006 Electricity Distribution Rate Handbook (RP-2004-0188) discusses the OEB's approach to true-ups for taxes (pp. 48-50). In issuing this document, the OEB considered two alternatives for the determination and recovery of variances between taxes paid and taxes included in rates. Option 1 provided a partial true-up for tax driven factors (such as legislative or regulatory changes), and Option 2 provided a full true-up for tax driven and operations driven factors. The OEB formally adopted the partial true-up approach, which is consistent with the scope of OPG's Income and Other Taxes Variance Account and Account 1592 for electricity distributors. In coming to this conclusion, the OEB stated that:

> ...it would be inappropriate to adjust rates to account for tax differences arising from variations in revenues or expenses. The Board also accepts that a partial true-up for changes in tax rates, rules, etc. represent a reasonable balance of risk between shareholders and ratepayer for items which are beyond the control of the distributor. (RP-2004-0188, 2006 Electricity Distribution Handbook, pp. 49-50).

OPG submits that a true-up for SR&ED ITCs is not consistent with the scope of Account 1592 and the related policy in OEB's 2006 Electricity Distribution Rate Handbook and therefore should not be recorded in the Income and Other Taxes Variance Account. OPG disagrees with the link that OEB staff suggest exists between a true up to the actual ITCs and resolution of tax audits, when they state, at p. 123 of their submission: “OEB staff is of the view that this [result from tax reassessments] should include a true up to the actual ITCs claimed per the tax audit ...” (emphasis added). Differences between actual and forecast ITCs cited by OEB staff are not a function of the tax audit but rather general forecast risk related to the level of underlying qualifying expenditures, a function of actual work programs and projects undertaken, as discussed earlier. If the OEB were to accept OEB staff’s argument on this issue, it would effectively mean that all variances between forecast and actual taxes could be in scope of the Income and Other Taxes Variance Account because they would all be inputs into the “results from tax reassessments.” OPG submits that this would not be a sensible result.

Moreover, as OEB staff recognize at p. 123 of their submissions, the Income and Other Taxes Variance Account is a settled matter in this proceeding. In the approved Settlement Agreement (Tr. Vol. 9, p. 1) under Issue 9.6, parties agreed that

> …the proposed continuation of deferral and variance accounts is appropriate on the basis of OPG's evidence. Provided that, for greater certainty, agreement to continue the accounts is not intended to imply agreement with the existing or proposed methodology, entries, or other terms relating to those accounts that are excluded from the settlement of issues 9.1, 9.2, and 9.3. (Ex. O1-1-1, p. 14).

Issues 9.1, 9.2 and 9.3 excluded the following three accounts: CRVA (Nuclear), Nuclear Liability Deferral Account, and Bruce Lease Net Revenues Variance Account. Issue 9.3 also excluded the Pension & OPEB Cash Versus Accrual Differential Deferral Account. The Income and Other Taxes Variance Account was not one of the exclusions and therefore has been settled.

On the basis of the above, OPG submits that a separate SR&ED ITC variance account would need to be established, should the OEB find that that a true up is warranted.

7.13.5 2014-2016 SR&ED ITCs

Although OEB staff’s proposed changes to the treatment of ITCs are prospective, they assert that, due to tax losses calculated in respect of the nuclear businesses during the 2014-2016 period, carrying forward of nuclear ITCs from the 2014-2016 period would have yielded revenue requirement reductions in the 2017-2021 period. Putting aside OPG's general disagreement with the carryforward approach discussed above, OPG disagrees with OEB staff's conclusion.

At page 122, OEB staff's submission notes that "OPG [has] indicated [during the hearing that] 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". These adjustments were outlined by the witness at Tr. Vol. 21, pp. 136-140.[95] Once these adjustments are applied to the 2014-2016 taxable income or loss amounts and the resulting nuclear ITCs carried forward are reduced to avoid "double counting" with the forecast ITCs included in the EB-2013-0321 payment amounts[96], the estimated amount of 2014-2016 ITCs that hypothetically would have been available to reduce the 2017-2021 regulatory taxes would be nil.

7.13.6 Property Taxes

LPMA submits that the OEB should reduce OPG's annual nuclear revenue requirement by $2M per year on account of property taxes. LPMA argues that the increase in OPG's forecast of property tax amounts over the test period is not justified in light of 2014 and 2015 actual amounts being lower than planned (LPMA argument, p. 20). OPG disagrees with LPMA's submission.

In Ex. F4-2-1, pp. 13-16 OPG provides an explanation of the forecast of property tax values. As noted at that evidence, the nature, basis, and components of OPG's property tax expense are unchanged from EB-2013-0321 and EB-2010-0008. The proposed property tax expense for the regulated nuclear facilities increases gradually over the test period, reflecting differences in

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[95] The three main adjustments to taxable income or loss for carryforward purposes are: i) removing any forecast tax losses already reflected in the revenue requirement underpinning the payment amounts in effect (e.g. nuclear tax losses were reflected in EB-2013-0321 payment amounts); ii) adjusting for the impact of tax additions and deductions that represent items for which the tax cost or benefit is already being passed on to ratepayers through deferral and variance accounts (e.g., variances from forecast DRP capital cost allowance deductions) ; and iii) removing tax savings related to disallowed expenses (e.g., OM&A costs disallowed in setting the EB-2013-0321 payment amounts). The first two adjustments ensure that the amount of regulatory taxable income or loss considered for carryforward purposes is not double counted with tax amounts being settled with ratepayers through other means, while the third adjustment attributes the loss between ratepayers and shareholders consistent with the 2006 Electricity Distribution Handbook (RP-2004-0188), pp. 53-55.

[96] Tr. Vol. 21, pp. 138-140.

municipal property tax rates and changes in property assessment values. OPG submits that the property tax values submitted in this Application are reasonable and should be approved on the basis of the written evidence. OPG further notes that the 2016 actual property taxes for the nuclear facilities came in at $14.1M (Ex. J14.2, Attachment 1), higher than the budget of $13.5M (Ex. F4-2-1, Table 2) and with a year-over-year increase of $0.9M from 2015. This is a higher increase than the average increase of $0.6M per year over the test period.

7.14 Other Costs

7.15 Issue 6.11

Secondary: Are the asset service fee amounts charged to the nuclear business appropriate?

There is an agreement to settle this issue (Ex. O-1-1, pp. 10; Tr. Vol. 9, p. 1).

8.0 OTHER REVENUES

8.1 Nuclear

8.2 Issue 7.1

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

There is an agreement to settle this issue (Ex. O-1-1, pp. 10-11; Tr. Vol. 9, p. 1).

8.3 Bruce Nuclear Generating Station

8.4 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?

OPG's submissions with respect to this issue are set out at pages 128-131 of its AIC. As in EB-2014-0730, EB-2013-0321, EB-2012-0002 and EB-2010-0008, the treatment of revenues and costs associated with the Bruce lease and associated agreements follows the OEB's decision in EB-2007-0905 which, in turn, was based on the requirements of O. Reg. 53/05. Specifically, that these amounts are to be calculated in accordance with Generally Accepted Accounting Principles ("GAAP").

OEB staff, QMA, LPMA, and OAPPA made submissions directly in relation to this issue. OEB staff submits that the revenue requirement changes arising subsequent to the Exhibit N1 Impact Statement should be reflected in the revenue requirement approved in this proceeding rather than, as initially proposed by OPG, in the Nuclear Liability Deferral Account and the Bruce Lease Net Revenues Variance Account (OEB staff argument, p. 126). OEB staff makes the same submission in relation to Issue 8.2. As OPG indicated during the hearing (Tr. Vol. 21, p. 42) and in its AIC (p. 133), it does not oppose this approach.

OAPPA argues that the OEB should disallow recovery of 50% of the costs relating to the Bruce lease. While conceding the LTEP, government policy and other social-economic benefits, it argues that the "Bruce NGS has no financial value beyond the test period." (OAPPA Argument, p. 15). The OEB can disregard OAPPA's assessment. Its argument has no legal force. As the OEB held in EB-2007-0905, the requirements of the regulation as they relate to the Bruce NGS are clear and unambiguous: OPG shall recover "all the costs it occurs with respect to the Bruce Nuclear Generating Stations." (O. Reg. 53/05, section 6(2)9)

Other parties, notably SEC and those that support it or take a similar position with respect to nuclear liabilities, take an indirect, disguised approach to the issue. As discussed further below in relation to Issue 8 (Section 9.0), in advocating for a cash form of recovery for all of OPG nuclear liabilities, they do not distinguish between the different methodologies applicable to the Bruce and prescribed facilities. As the OEB held in specifically rejecting a cash-based, non-GAAP approach to determining OPG's Bruce related nuclear liabilities:

> The Board finds that the appropriate method to calculate OPG's test period revenues and costs related to the Bruce stations is to use amounts calculated in accordance with GAAP. OPG's investment in Bruce is not rate regulated. In the Board's view, it would be not be a reasonable interpretation of Section 6(2)9 and 6(2)10 to find that OPG should use an accounting method to determine revenues and costs that an unregulated business would otherwise never use. ...
>
> The Board will require that Bruce lease revenue be calculated in accordance with GAAP for non-regulated businesses. The Board's rational is the same as its rationale for requiring that the cost of the Bruce nuclear liabilities be computed in accordance with GAAP – it is not reasonable to interpret the regulation to find that OPG can calculate revenues from an unregulated activity using an accounting policy that an unregulated company would not be permitted to use. (EB-2007-0905, Decision with Reasons, pp. 109-110).

SEC and other intervenor cash based approach to nuclear liabilities should be rejected by the OEB.

9.0 NUCLEAR WASTE MANAGEMENT AND DECOMMISSIONING LIABILITIES

9.1 Issue 8.1

Primary: 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?

OPG operates the largest nuclear fleet in Canada, and accounts for more than 90% of nuclear waste nation-wide. OPG has a legal and social obligation to decommission its nuclear facilities at the end of station life and for the safe, responsible, long-term management of used nuclear fuel and other irradiated waste. The costs of these obligations are recognized in OPG's financial statements, on a present-value basis, in accordance with GAAP in the periods they are incurred, by matching those costs to the benefits (i.e. electricity generation) derived from the nuclear facilities over time (Ex. C2-1-2, p. 7).

A large portion of these costs are funded by OPG under the Ontario Nuclear Funds Agreement ("ONFA"). ONFA is a bilateral agreement between OPG and the Province of Ontario, which requires monies to be set aside into two segregated funds, the Decommissioning Fund ("DF") and the Used Fuel Fund ("UFF") held in third-party custodial accounts. The remaining costs are paid out of OPG's operating cash flow on a pay-as-you-go basis (referred to as "internally-funded"). As detailed in Ex. C2-1-2 and discussed below, ONFA funding rules have been structured such that OPG has been required to fund a substantial portion of the underlying used fuel liabilities in earlier years (i.e. front-loading), effectively as a form of funding conservatism. OPG can use the funds solely for the purpose of paying for eligible expenditures on nuclear liabilities.

The OEB recognized the significance of these long-term obligations to OPG's regulated cost of service in the first OPG payment amounts proceeding and established, within the framework of O. Reg. 53/05, separate methodologies for recovering the underlying costs for the Bruce and prescribed facilities (EB-2007-0905 Decision with Reasons, p. 91). As discussed later in this section, the OEB did so after careful consideration of the accounting, funding and rate making aspects of the nuclear liabilities based on a fully developed record that included submissions from most of the intervenors making submissions on the issue in this proceeding.

In the EB-2007-0905 proceeding, the OEB rejected arguments that the methodologies it established should be made interim and a new process convened to investigate the matter further. Since then, the methodologies approved in EB-2007-0905 have been applied without any substantial controversy. In the last three OPG payment amounts proceedings and two D&V account applications the OEB has reaffirmed the methodologies approved in EB-2007-0905. In this proceeding, OPG has proposed to continue with these same methodologies and recover approximately $1.8B (including taxes) for these costs over the five years, based on the Exhibit N1 Impact Statement (Ex. C2-1-2, p. 3, Chart 1). This is equivalent to about $360M per year and represents just over 10% of the total revenue requirement request. The proposed cost levels are consistent with the last payment amounts proceeding, where OPG sought and was approved to recover approximately $395M per year.[97]

OEB staff do not oppose continuing the existing OEB-approved methodologies in this proceeding. Their submissions focus on two issues. First, that the reductions resulting from the updated ONFA contribution schedule should be recovered in the revenue requirement, rather than through applicable variance accounts[98] (OEB staff argument, pp. 128-129). LPMA and CME agree with OEB staff on this issue (LPMA argument, p. 21; CME argument, paras. 288-291). OPG does not oppose this approach, as indicated previously (AIC, p. 133). OPG notes that reflecting the changes in revenue requirement, would reduce the average annual recovery for the costs to about $300M, or about 25% lower than in the last proceeding.

OEB staff next request that the OEB direct OPG to file a study of various costs recovery methodologies for nuclear liabilities including those used in other regulatory jurisdictions in its next cost-based nuclear payment amounts application, (OEB staff argument, pp. 129-133). As

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[97] The two-year figure of approximately $395M is computed from EB-2013-0321 as the sum of the following, divided by 2: (i) Ex. C2-1-1, Table 1, line 18, col. (e) + col. (f), and (ii) (Ex. F4-2-1, Table 5, line 4 - line 5 in cols. (b) + (c)) x 25%/(1-25%).

[98] The impact is a revenue requirement reduction, before consideration of regulatory tax loss carryforward effects during the period, of $304.7M, rather than $294.6M cited in OEB staff's argument at the top p. 129. The difference between $304.7M and $294.6M is explained in footnote 58 of the AIC (p. 133). The $304.7M figure is properly reflected in OEB staff's argument in Table 35.

discussed in Section 9.1.6, OPG does not see that a study is necessary, but does not oppose a study if it would be of value to the OEB.

In contrast to OEB staff, SEC, CCC, LPMA and CME oppose OPG's request to continue recovery of nuclear liabilities using the OEB's previously approved methodology (SEC argument, pp. 99-110; CCC argument, pp. 27-34; LPMA argument pp. 21-23; CME argument pp. 55-61). They argue for a revenue requirement reduction of $423.2M over the IR term.[99]

These intervenors propose that the OEB should determine the revenue requirement based on the funding payments required by the current ONFA contribution schedules and pay-as-you-go expenditures on the "internally funded" nuclear liability programs, rather than the existing methodology (SEC argument, para. 8.1.26; CCC argument, p. 28; LPMA argument, p. 21; CME argument, para. 298). The motivation for their request is plain: the total cash funding amounts for this particular period, based on the 2017-2021 ONFA Reference Plan, are expected to be lower than the revenue requirement based on the approved OEB methodology.[100]

The parties' submissions do not advance any substantive principles which justify a change to the OEB's established methodology, other than that OPG should not collect money from ratepayers when, as intervenors claim, "those monies will never actually be spent on nuclear liability costs" (SEC argument, para. 8.1.2). Parties also claim that the current fully funded status of the segregated funds is a significant new development (CME argument, para. 293).

The parties make a number of other submissions which, while addressed by OPG below, do not support a change in methodology. These submissions include SEC's suggestion that the proposed cash-based method is somehow novel and was not previously considered by the OEB or intervenors in the EB-2007-0905 proceeding (SEC argument, p. 100-102). Both SEC and CME also confuse matters by advancing a flawed understanding of ONFA, culminating in a

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[99] While OPG agrees with this figure, it rejects SEC's characterization that OPG somehow improperly or incorrectly presented information during the proceeding (SEC argument, paras. 8.2.13 and 8.2.19). SEC asked for certain information, which it received, and now appears to object that OPG provided what SEC asked for rather than what SEC now believes it really wanted. While SEC now complains that there are "a lot of number flying around" (SEC argument, para. 8.2.5) at least some were provided in response to specific requests from SEC. Moreover, SEC ignores the fact that in Undertaking J20.7, OPG specifically provided a clear road-map on how to calculate the tax impacts that SEC now says were not properly presented.

[100] LPMA's submission speaks for itself in this regard when it states: "The Province (OPG's shareholder) is emphasizing the need for ratepayer relief from high electricity bills. What better way to accomplish this than to move to the cash methodology for nuclear liabilities?" (LPMA argument, p. 21).

claim that the Province has, through ONFA, decided the appropriate amount that should be recovered in payment amounts. CCC takes a slightly different tact and focuses its argument on assertions that OPG would not be harmed by the change in methodology (CCC argument, pp. 29-32). Suggesting that a change in the recovery methodology for a long-term obligation is somehow consistent with the OEB "emphasizing the need for continuous improvement" in OPG's operations, LPMA largely echoes the positions of the other intervenors, as does CME (LPMA, argument, p. 21; CME argument, paras. 280-333).

OPG disagrees with the parties' positions and submits that their request for a change in methodology should be rejected. It is not appropriate to switch to a cash-based methodology of recovery for the nuclear liabilities costs going forward. Below OPG responds to the main points raised by parties by highlighting why a cash-based methodology would be inconsistent with sound rate-making principles and would mean that OPG will not recover the from ratepayers the full costs of the nuclear liabilities attributable to the nuclear production over the IR term.

In making their arguments for switching to the cash-based methodology, the intervenors also ignore the important differences between the prescribed facilities and the Bruce facilities in terms of the approved recovery approach and the O. Reg. 53/05 requirements. Intervenors fail to acknowledge that their proposed reduction of $423M over the IR term is actually made up of a requirement <u>increase</u> of $634M for the prescribed facilities and a revenue requirement <u>decrease</u> of $1,057M for the Bruce facilities.[101] Their proposed approach for the Bruce facilities would be contrary to the legal requirements of O. Reg. 53/05 as previously interpreted by the OEB.

Based on the positions summarized above, and fully developed in the sections that follow, OPG respectfully submits that the OEB should continue with the methodology adopted after careful consideration in EB-2007-0905 and followed in every subsequent OPG proceeding that has involved nuclear liabilities.

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[101] The prescribed facilities figure is calculated: as Ex. J20.7, Chart 3, line 12, Total column x (1+0.25/(1-0.25)). The Bruce facilities figure is calculated as: Ex. J20.7, Chart 3, line 22, Total column x (1+0.25/(1-0.25)).

9.1.1 Intervenors Misstate Both the Issues and the OEB's Decision in EB-2007-0905

The issue of nuclear liabilities was the largest single issue in EB-2007-0905 involving some five days of testimony and fully 50 pages of the OEB's Decision with Reasons. The approach to nuclear liabilities was the subject of intense scrutiny by parties and the OEB, with SEC, CME, CCC and VECC in particular making extensive submissions on this issue. The proceeding included a detailed consideration of the proper interpretation of O. Reg. 53/05 as it relates to the nuclear liabilities costs and related variance and deferral accounts for the prescribed and Bruce facilities, as well as a detailed review of potential methods for including these costs in the revenue requirement. SEC's suggestions to the contrary are wrong (SEC argument p. 100-102).

A review of the EB-2007-0905 decision readily demonstrates that:

- the OEB carefully reviewed and interpreted the provisions of O. Reg. 53/05;
- was fully aware of the features of ONFA;
- understood how contributions under ONFA differed from various rate recovery mechanisms under consideration;
- considered different rate recovery mechanisms; and
- recognized that a cash outlay approach to recovery would produce a different result than a GAAP based methodology and that the funding status of the UFF and the DF could and would change over time.

In EB-2007-0905, the OEB had the benefit of intervenors' detailed submissions that dealt extensively with many of these issues. Indeed, as it relates to cash, OPG had originally proposed that the calculation of Bruce revenues be done on a cash basis – a proposition, as set out above – that was rejected by the OEB (EB-2007-0905, Decision with Reasons, p. 110). As detailed in Ex. C2-1-2, page 14 and at pages 138-142 of the AIC, the OEB adopted a depreciation-based method, based on accounting principles, for prescribed facilities and, in accordance with O. Reg. 53/05 requirements, a pure GAAP-based method for the Bruce facilities.

As explained further at the above references, both methods recover capitalized ARC through depreciation over the station life and accrued variable costs for used fuel and other irradiated waste as that waste is generated over time. For the Bruce facilities, accretion expense (i.e., the growth in the present value of the accounting liability due to the passage of time, net of earnings on the nuclear segregated funds) is included in the methodology. For the prescribed facilities, OEB effectively replaced these components by a formula whereby the lesser of the undepreciated ARC and unfunded nuclear liabilities as reported in OPG's financial statements earns the weighted average accretion rate (currently 4.95%[102]), while the remainder of the undepreciated ARC, if any, earns the full weighted average cost of capital.

SEC misstates the issues in the EB-2007-0905 proceeding. SEC's claims include that the cash-based (funding) recovery methodology was not considered; that the record was not clear that there would have been a significant difference between GAAP-based recovery and ONFA-based recovery; that the OEB was unaware of differences between ONFA requirements and accounting liabilities; and that the parties accepted that nuclear liabilities would be included in rates based on accounting principles (SEC argument, para 8.1.5-8.1.8). Given that SEC asserts these matters for the first time in its argument, and did not raise them in the hearing, they can only be addressed now by referring to the EB-2007-0905 decision and the underlying record in that case as OPG does below.

SEC claims, incorrectly, that the cash-based method "never came up" in EB-2007-0905 and that the OEB never turned its mind to it (SEC argument, paras. 8.1.5, 8.1.8). In fact, OPG adduced evidence regarding future ONFA contributions, including a schedule of future contributions going out to 2036 based on the then-current ONFA reference plan (EB-2007-0905, Ex. J15.11, Attachments 2 and 3), and internally funded expenditures (EB-2007-0905 Ex. H1-1-3). The OEB specifically adverted to this evidence in the decision:

> OPG noted that its total proposed revenue requirement for nuclear waste management and decommissioning costs (as shown in [OEB Decision] Table 5-4) would be less than the company's cash flow requirements during the test period (expected contributions to the segregated funds and nuclear costs funded through operations). (EB-2007-0905, Decision with Reasons, pp. 81-82).

SEC's suggestion that the record in EB-2007-0905 was not clear regarding the differences between GAAP-based costs and cash-based amounts is equally inaccurate (SEC argument, para. 8.1.9). For example, OPG filed a separate, stand-alone exhibit (EB-2007-0905, Ex. H1-1-

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[102] Ex. N1-1-1, p. 16.

3) specifically detailing the proposed revenue requirement impacts and corresponding cash outlays. This exhibit showed, at page 2, that OPG's proposed revenue requirements were significantly lower than the expected cash outlays over the 21-month test period to December 31, 2009.

Further, SEC's claim that the OEB did not consider "whether the accounting methods governing the calculations of nuclear liabilities are appropriate for ratemaking purposes" is also wrong (SEC argument, para. 8.1.8). As evident from the below passage (also set out in Ex. C2-1-2, p. 15), the OEB considered whether financial accounting values at large represented an appropriate basis for rate recovery, not just for the narrower issue of the appropriate rate of return for the ARC component of rate base, as SEC claims (SEC argument, 8.1.6):

> The Board will accept inclusion in the revenue requirement of depreciation expense for the nuclear plants computed in accordance with GAAP, as proposed by OPG. Under GAAP, ARC included in the net book value of fixed assets is depreciated like any other fixed asset cost. It appears as an expense in OPG's income statement. The Board finds that this approach results in a rational allocation of cost. (EB-2007-0905, Decision with Reasons, pp. 88-89).

In fact, in <u>direct contradiction</u> of SEC's claim that "all parties to the proceeding accepted that nuclear liabilities would be included in rates based on accounting principles" (SEC argument, para. 8.1.6), SEC said the following in its EB-2007-0905 argument:

> In the case of nuclear negative salvage, it is submitted that the Board should determine independently what it believes a reasonable recovery amount should be in any given year, taking into account the fact, noted earlier, that this is a "saving for retirement" type of problem. <u>To the extent that the accounting rules mandate a different calculation, the Board should accept that there may be a difference, because the goals of the Board in balancing the interests of the ratepayers and the Applicant may not, in this case, be the same as the goals of GAAP in achieving the clearest, and most conservative, financial statement presentation.</u> (EB-2007-0905, SEC argument, paras. 167-168 (emphasis added)).

In turn, VECC and CME's submissions specifically distinguished between rate recovery and the ONFA funding mechanism. For example, VECC stated:

> In the present case, <u>the Board is faced with implementing a regulatory mechanism for the recovery of Nuclear Liabilities where the utility has,</u> in conjunction with its shareholder, <u>created its own 'sinking fund', setting aside</u>

> amounts in segregated funds that are intended to cover the cost of the [ONFA] Reference Plan. (EB-2007-0905, VECC argument, para. 31 (emphasis added)).

And CME stated:

> The fact that OPG has agreed with its owner, the Province of Ontario, to make payments into its nuclear Asset Removal and Waste Management funds pursuant to a payment schedule that is heavily front-end loaded, should not have any influence on the rate-making approach the Board applies to recover Asset Retirement Costs from ratepayers. (EB-2016-0152, CME argument, para. 88 (emphasis added)).

In direct response to these submissions, the OEB found the following in its decision, clearly demonstrating full awareness of the availability of a funding-based methodology:

> CME advocated its "Cost of Service Supplement to ARC Depreciation" concept as a model that the Board should consider in the future, while VECC advanced a sinking fund methodology as the right approach. Neither model was fully developed in the intervenor arguments. It appeared to the Board that both models would require the Board to develop an alternative funding schedule in order to calculate the revenue requirement. The Board questions the utility and practicality of developing alternatives to the funding scheduled set out in the ONFA. (EB-2007-0905, Decision with Reasons, p. 91 (emphasis added)).

SEC's statement that "at no time did the Board know that the amounts for nuclear liabilities on the financial statements of OPG were calculated in a manner inconsistent with ONFA" (SEC argument, para. 8.1.8) is also demonstrably wrong. This is plain from the headings and content of the OEB's decision, which include sections devoted to the questions on the funding (EB-2007-0905, Decision with Reasons, section 5.1.2) and the financial accounting bases for nuclear liabilities (EB-2007-0905, Decision with Reasons, section 5.1.3). In those sections, the OEB reviewed, in detail, the basis for OPG's obligations under the ONFA and the relevant financial accounting standards, respectively.

As an example, the decision demonstrates that the OEB was aware of the difference between the discount rates used in accordance with GAAP to determine the nuclear asset retirement obligation ("ARO") and the rate used for ONFA funding purposes. The EB-2007-0905 Decision with Reasons noted, at page 66 in discussing funding, that "[t]he Province also guarantees an annual rate of return of 3.25% above the Consumer Price Index on the portion of the used fuel fund related to the first 2.23 million used fuel bundles." In contrast, with respect to the financial accounting liability, at page 86, footnote 59 of the EB-2007-0905 Decision with Reasons, the

OEB stated: "[t]he Board understands, however, that only a portion of the $10.8 billion ARO liability as at December 31, 2007 […] has been calculated using a 4.6% discount rate; the balance of the ARO liability has been measured using a 5.75% discount rate."

The matter of the discount rate is discussed below in Section 9.1.4. Here it is worth noting, that while SEC's submission in this proceeding expresses surprise at the difference between accounting and funding discount rates (SEC's argument, p. 105, footnote 507), SEC's own EB-2007-0905 submission (page 53, para. 214) recognized the difference between these two rates. SEC also explored this issue in proceedings that followed EB-2007-0905.[103]

Given the evidence on record in EB-2007-0905, intervenors' submissions in that proceedings and the OEB's findings in the Decision with Reasons, SEC's suggestion that a funding-based recovery methodology and differences between ONFA and accounting determinations is new information that was not available to intervenors and the OEB or actively considered by them is fundamentally wrong and should be rejected.

To the same effect, CME's claim that that the current funded status of the UFF and DF represents a change since EB-2007-0905 (CME argument, para. 293) and therefore supports a new methodology, is also incorrect. As set out in Ex. C2-1-2, page 16, while the UFF has not historically been overfunded, the DF was considered overfunded at the time the OEB established the nuclear liabilities methodology in the EB-2007-0905 proceeding, and this was specifically adverted to in the OEB's EB-2007-0905 Decision with Reasons at page 66. Subsequent decisions have also recognized this (see EB-2013-0321, Decision with Reasons, p. 109). In fact, the OEB specifically contemplated that the nuclear liabilities may be fully funded at points in the future when it stated "[i]n Board's view, [OPG's proposed] rate base method over-compensates OPG when OPG's nuclear liabilities are fully funded" (EB-2007-0905, Decision with Reasons, p.89 (emphasis added)).

[103] For example, in EB-2012-0002 SEC specifically sought information on differences in various discount rates involved in the calculation of funding and accounting values. SEC's interrogatory Ex. L-1-7 SEC-12 in EB-2012-0002 asked: "Please explain the different applications of the 5.15% discount rate, the 3.43% discount rate, the 4.8% discount rate, and the 5.58% accretion rate. Please include in the explanations examples of the sensitivities of the calculations in which each is used to changes, up or down, in the particular rate. Please include in your answer the source of the rate, and the statutory, regulatory, or other authority for the use of that rate." OPG provided a comprehensive response.

In summary, all of the issues that intervenors now raise were considered by the OEB in EB-2007-0905 in establishing the approved methodologies for the prescribed facilities and the Bruce facilities. These issues, therefore, provide no basis for overturning the OEB's approved methodologies.

9.1.2 Intervenors Ignore the Provisions of O. Reg. 53/05 and the Proper Treatment of Costs of the Bruce Facilities

The OEB's decision in EB-2007-0905 determined that based on O. Reg. 53/05 sections 6(2)9 and 6(2)10, it would be inappropriate to calculate OPG's nuclear liabilities costs related to the Bruce stations in a manner that an unregulated entity would not use (EB-2007-0905 Decision with Reasons, p. 109). Therefore, it directed OPG to calculate the Bruce portion of the nuclear liabilities costs using GAAP.[104] Despite this long-standing difference in treatment, none of the intervenor submissions directly address this point.

Clearly, adopting the intervenor nuclear liabilities ratemaking proposals for the Bruce assets would be inconsistent with the OEB's prior determination on the proper interpretation of the regulation. During the hearing, Mr. Mauti reinforced the importance of considering the impacts on the Bruce and prescribed facilities separately when assessing nuclear liabilities as follows:

> MR. MAUTI: I just wanted to make sure that -- I know this is a complicated area, but when it comes to Bruce versus prescribed, the Board in its 2007 decision made what I'll call a bright line distinction between the two, that the Bruce facilities were to be treated as an unregulated business of OPG's, and it would be reporting its net costs or revenues on a GAAP basis going forward. …
>
> You're going to end up with some fairly big numbers going in different directions for both Bruce and prescribed. And given the Bruce basis is on a GAAP basis, I wanted to point that out that, that distinction between the two is very important when looking at the results of this undertaking and just in general, when evaluating the methodologies. While those methodologies are largely consistent on an accrual basis right now for both prescribed and Bruce for a significant portion of those recoveries, any differences going forward I think you have to keep in mind that Bruce basis as recovery on a GAAP foundation as being a very important distinction. So I just wanted to flag that to make sure it was clearly understood. (Tr. Vol. 21, pp. 147-148).

[104] The methodologies for the prescribed facilities and the Bruce facilities are discussed in Ex. C2-1-1, Ex. C2-1-2 and in the AIC (pp. 139-142).

Ultimately, as set out in Ex. J20.7 and noted above, the impact of moving the prescribed facilities to a cash methodology, while (properly) maintaining the Bruce facilities on the approved GAAP-based method would be to significantly increase the revenue requirement over the IR term by $634M. While OPG is not proposing to move to a cash basis for either the prescribed or Bruce facilities, it emphasizes the importance of considering the two separately when evaluating a change in methodology.

9.1.3 ONFA is a Set-aside, Funding Mechanism, Not a Cost-based or Rate-making View of Nuclear Liabilities

Parties to the EB-2007-0905 proceeding proposed a range of different methods for recovery of OPG's nuclear liabilities costs. Some parties, like SEC,[105] proposed accounting-based methods while, others, like VECC and CME,[106] proposed methods that were substantially different than GAAP costs. However, while they differed on their approaches, all parties were operating from the same fundamental principle – recover the costs of nuclear liabilities over the productive life of the nuclear facilities which, together with interest or return, would yield recovery from ratepayers of the amount necessary to meet the decommissioning and nuclear waste obligations. This principle has not changed since the EB-2007-0905 proceeding.

SEC referred to this as a "saving for retirement" problem, noting that, for a utility, "matching the cost to the production is generally the most stable form of saving" (EB-2007-0905, SEC argument, para. 161). VECC recommended a "sinking fund" approach, noting that annual ratepayer payments over the life of the obligation would be preferred because this "would result in far less rate shock, would promote rate stability, and would be consistent with an appropriate intergenerational sharing of the cost of Nuclear Liabilities across all ratepayers" (EB-2007-0905, VECC argument, pp. 9-10). CME identified the need for "the estimated annual amount needed, over and above the ARC depreciation amount, to produce, at the end the economic life of the nuclear assets, the portion of the fund needed to retire and decommission the asset which will not be funded by ARC depreciation and accrual thereon" (EB-2007-0905, CME argument, para. 91). Leveraging some of the concepts advanced by intervenors for the prescribed facilities, the OEB chose not to 'reinvent the wheel' and adopted an accounting-based depreciation approach

[105]EB-2007-0905 SEC argument, paras. 175-178.
[106]EB-2007-0905, CME argument, paras. 68, 92-93; EB-2007-0905, VECC argument, para. 26.

that resulted in a “rational allocation of cost” (EB-2007-0905, Decision with Reasons, p. 88) over the nuclear stations’ productive lives.

It is telling that none of the parties (including OPG) recommended and the OEB did not adopt the ONFA-based funding recovery method in EB-2007-0905. OPG submits that this was precisely because parties and the OEB recognized: 1) that the ONFA was a set-aside, funding mechanism that was never designed to be a proper measure of OPG’s costs or ratepayers’ payments; 2) that it did not align with the cost recovery objectives articulated by parties; and 3) that, therefore, it should be treated as separate and distinct from the basis upon which payment amounts are set.

VECC correctly made this distinction, as noted above but worth repeating, when it stated that the OEB was faced with “implementing a regulatory mechanism for the recovery of Nuclear Liabilities where the utility has […] created its own ‘sinking fund’, setting aside amounts in segregated funds that are intended to cover the cost of the[se liabilities].” (EB-2007-0905, VECC’s argument, para. 31). None of this has changed since EB-2007-0905.

ONFA funding and pay-as-you-go internally funded expenditures remain an inappropriate basis for cost recovery, as further explained below. For these reasons, intervenor submissions are incorrect that the cash-based methodology “passes through the actual costs to OPG of Nuclear Liabilities” (CCC argument, p. 34).

The ONFA was put in place to provide prudent financial backing for the company’s nuclear liabilities. The ONFA funding mechanism was established consistent with a growing trend in international jurisdictions to place money aside for the long-term management of nuclear liabilities, in recognition of the fact that these liabilities will be discharged many years after the nuclear generating stations have closed (Ex. C2-1-2, p. 8). Contrary to intervenors’ claims, the ONFA, a contractual agreement, is neither the Province’s view of accounting for nuclear liabilities costs over the stations’ operating lives nor its expression of public policy or direction to the OEB as to how much money should be collected from customers in a given period, as SEC implies (SEC argument, para. 8.1.1).

Conversely, as SEC does note correctly, the OEB “is not charged with … decisions” on “how much should be spent currently, and how much should be set aside for future costs” (SEC argument, para. 8.1.27). As discussed in Ex. C2-1-2 (pp. 10-11) and in the EB-2007-0905 proceeding, the ONFA was structured from the outset to ensure that monies were contributed well in advance of the end of operations, which resulted in significant “front-loading” of the funding.[107] Among other things, this included a substantial contribution of $3B by the Province to the DF in 2003.[108] In addition, the Province instituted UFF funding requirements that resulted in about three-quarters of the long-term used fuel management costs being funded over the nuclear stations’ remaining operating periods assumed at the inception of the ONFA (rather than the significantly longer operating periods currently expected for most units on the basis of refurbishment and life extension decisions made since the early 2000s).[109] It is not surprising that the DF has been fully funded from the outset of the ONFA, while the UFF has had significantly declining contribution requirements. As part of EB-2007-0905, OPG provided the UFF contribution schedule in Ex. J15.11, which the OEB noted had contributions over the period 2008 to 2017 with “smaller amounts being contributed thereafter” (EB-2007-0905, Decision with Reasons, p.66).

Specifically, EB-2007-0905 Ex. J15.11, Attachment 2 showed that total UFF contributions were set to decline from $454M in 2008 to $83M in 2017, to $29M in 2021. For a fuller comparison, EB-2010-0008, Ex. C2-1-1, Attachment 1 shows the total contributions from 2007 going back to the inception of the ONFA. For that period, the Province and OPG’s contributions (before fund earnings) totaled $3.7B to the UFF and $3.6B for the DF.[110]

Although these amounts were set aside pursuant to the ONFA, this does <u>not</u> mean that they have been incurred as costs by OPG <u>or</u> recovered from ratepayers. Equating the pace and amount at which funds are set aside by the company with their recovery from ratepayers is the

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[107] In para. 8.1.24, SEC implies that ONFA funding requirements are somehow a substitute for “decisions of accounting bodies” with respect to the determination of costs. ONFA funding decisions have nothing to do with accounting principles that seek to match costs across time.
[108] EB-2010-0008, Ex. C2-1-1, Attachment 1, Table 1.
[109] Further details can be found in Ex. C2-1-2, page 11, footnote 8. This also means that if there is a future change in baseline cost estimates or assumptions that increases OPG’s nuclear decommissioning or waste management obligations, incremental ONFA funding may be required over a much shorter timeframe than the equivalent accounting costs would be recognized.
[110] As explained in Ex. J21.3, these contributions include funding for all future ONFA-eligible costs, even those associated with incremental used fuel and other irradiated waste not yet generated. This is in contrast to accounting values that recognize only committed costs and exclude what are considered to be incremental variable costs associated with future wastes not yet generated. As Ex. J21.3 notes, the inclusion of future waste volume accounts for approximately $1B of the 2016 year-end ONFA segregated fund balance.

fundamental fallacy of the argument advanced by interveners in the current proceeding.[111] Parties largely avoided this mistake in EB-2007-0905 when they recognized the front-end loaded nature of ONFA funding and advocated for an allocation of cost over the station's life. Put differently, a utility may choose (or, in this case, be required) to set aside funding to help manage future expenditures, such as when a station is shut down, even if the costs of those expenditures have not yet been collected from ratepayers.

To the extent future costs were effectively "pre-funded" and not yet recovered from ratepayers, they must still be recovered to ensure that OPG is held whole. The recovery of these costs over the life of the station, in a manner that reasonably matches the benefits of electricity generation received by ratepayers, is what the OEB's approved methodology contemplated and what OPG seeks in this proceeding. SEC's claim that "there is no benefit to current customers" (SEC argument, para. 8.1.31) of paying for these costs is thus incorrect, as is CCC's proposition that "[i]t would seem obvious […] that OPG is held whole if it recovers through payment amounts that year's contributions to the Used Fuel and Decommissioning Segregated Funds and its internally funded expenditures" (CCC argument, p. 29).

OPG provided an analysis that compares amounts expended by OPG as ONFA contributions and internally funded expenditures to amounts recovered from ratepayers (including proxy amounts recovered through interim rates set by the Government for the period from April 1, 2005 to March 31, 2008) for the period April 1, 2005 to December 31, 2016. This is found in Ex. C2-1-2, Charts 3 and 4 on a pre-tax basis and Ex. J20.7 on an after-tax basis. Referring to the latter, which CCC and CME argue is more representative, this difference has been to the considerable benefit of ratepayers (CCC argument pp. 30-31; CME argument paras 328-330). As shown in Ex. J20.7, since April 1, 2005, OPG estimates it has recovered approximately $885M less than it has funded to December 31, 2016 in nominal dollars. Once the tax gross-up effect is taken into account, the amount would be closer to $1.2B.[112]. Had a cash-based recovery methodology been in place over this period, ratepayers would have paid that much more. However, OPG submits (and expects that intervenors would agree), this would not have been an optimal outcome given that the ONFA is structured to collect funds over a relatively

[111] For example, SEC submits that the recovery of Nuclear Liabilities "is a funding exercise, driven by intergenerational equity and fairness," which completely misses the point (SEC argument, para. 8.1.15).
[112] The amount would be higher once the time value of money effects are considered.

short period of time and not to ensure fair collection during the entire operating lives of the nuclear stations.

CCC attempts to cast doubt on OPG's estimate of historical differences between amounts recovered from ratepayers and amounts expended for ONFA contributions and internally funded expenditures, but its argument misinterprets OPG's evidence (CCC argument pp. 29-32). CME repeats CCC's arguments (CME argument paras.323-333). CCC argues that in looking at history, the period from April 1, 2005 to March 31, 2008 should be disregarded, in part, because it believes OPG's analysis "is based on the assumption that interim rates [set by Government for that period] were predicated on the inclusion of these costs using the methodology created by the Board in the EB-2007-0905 proceeding" (CCC argument, pp. 31-32). This is not accurate. In EB-2007-0905, the OEB accepted that the Province used the rate base method that OPG proposed in EB-2007-0905, but that the OEB rejected, to determine the ratemaking costs of the nuclear liabilities during the interim period of Provincial regulation prior to OEB regulation (EB-2007-0905, Decision with Reasons, pp. 96-98). At Ex. C2-1-2, p. 25, lines 12-15, when OPG explained that it applied "the revenue requirement methodology accepted by the OEB in that proceeding as having been used by the Province to set interim rates," it was referring to the rate base methodology the OEB accepted had been used in the interim period, not the methodology that the OEB established for the post-April 1, 2008 period.[113]

While CCC and CME question the relevance of the period prior to OEB regulation, an examination of the difference between the amounts contributed to the segregated funds or expended, on one hand, and the amounts recovered in rates, on the other, shows "the significant front-end loading of contributions under the ONFA funding mechanism" (Ex. C2-1-2, p. 26). Information regarding the pre-April 1, 2008 period is helpful and, indeed, necessary to appreciate the significant extent to which the ONFA by front-loading the funding profile has impacted OPG's cash flow.

9.1.4 Other Intervenor Arguments Are Without Merit

CME and CCC raise similar issues with the tax implications of the existing methodology, effectively in reference to the tax gross up component on collection of costs from ratepayers.

[113] As noted at Ex. C2-1-2, p. 25, lines 12-13, OPG's analysis of proxy amounts recovered in the interim period uses figures on record in the EB-2007-0905 proceeding.

CME directly argues that ratepayers are being unreasonably asked to "bear an increased tax burden simply to satisfy OPG's accounting methods" (CME argument, para. 302). CCC claims that the existing methodology is flawed because, due to the effect of the tax gross up on recovered amounts and the tax shield associated with segregated fund contributions, it results in a higher revenue requirement when the contributions are lower. Both of these submissions are misconceived and should be rejected.

At the outset, OPG notes that the treatment of income tax impacts for the nuclear liabilities in this proceeding is exactly the same as in previous proceedings. Exhibit F4-2-1, page 1 specifically notes that "[f]or all tax matters for the prescribed facilities addressed in this exhibit OPG has applied the same principles and methodology as in EB-2013-0321." The calculation of the tax impacts specific to the nuclear liabilities is explained in Ex. C2-1-2, p. 15, lines 9-22 and p. 17, lines 3-13.

To the specific arguments advanced by these parties, there can be only one response – it would be unreasonable to deny OPG the properly determined amount for taxes it will have to pay on the revenues it legitimately collects under an OEB-approved methodology. Such a denial would not allow OPG to recover its approved cost levels and preclude the opportunity to earn the allowed rate of return. Moreover, it stands the matter on its head to suggest that an appropriate regulatory methodology should be changed because of the tax consequences which flow from that methodology. If the methodology is appropriate based on regulatory principles, the resulting taxes, properly calculated, are necessarily appropriate.

The tax effects mechanically flow from the cost elements included in the pre-tax revenue requirement, nothing more and nothing less. This includes the tax shield on ONFA contributions, which OPG passes on to ratepayers when it receives it. When OPG does not receive such a benefit, there is nothing to pass on. Finally, both CCC and CME fail to recognize that significant tax shield benefits would have been realized in prior years, given the front-end loaded nature of the ONFA contributions.

CME notes the difference that arises between funding and accounting values due to different discount rates and asks the OEB to "reduce OPG's ARO discount rate to match the ONFA prescribed amounts" (CME argument, paras. 311-316; 320).[114] SEC claims that OPG decided "to use a different approach to discount rates to value its future liability, compared to that mandated by the Province in ONFA." (SEC argument, p. 105, footnote 507). These are not accurate characterizations. As explained in Undertaking J21.3, the different discount rates are derived based on different requirements and are used for different purposes. The Province, through the ONFA, has determined the discount rate to be used for funding purposes, which establishes the long-term target rate of return on the ONFA segregated funds. In contrast, US GAAP requires that any calculation of an initial ARO and all subsequent increases in the underlying undiscounted cash flows, are present valued using a discount rate is in effect when the ARO is established or increased. US GAAP requires that discount rate be determined using a credit adjusted risk- free rate that matches the steam of cash flows associated with the underlying liability (Ex. L-8.2-1 Staff-207).[115] Contrary to SEC's claim at page 105, footnote 507 of their argument, OPG is not a position to use the contractually-determined ONFA discount rate to determine its nuclear liabilities in accordance with GAAP.

OPG also notes that the weighted average accretion rate (and, to a lesser extent, the ONFA rate that considers inflation) will continue to change over the life of the nuclear liabilities. The accounting rate will change as new tranches of the liability (up or down) are recorded to reflect changes in underlying cost estimates or assumptions, and as expenditures against the liability draw down previously set up tranches. In some ways, the point-in-time comparison of discount rates has as little value as the point-in-time comparison of the funded status of the nuclear segregated funds – both are certain to change over time.

The submissions by CME and SEC also are opportunistic. For many years, the ONFA funding rate was lower than the ARO discount rate and this has been known to the OEB and parties, including, as discussed in Section 9.1.1, at the time of EB-2007-0905. At no point in the past has CME, SEC, or any other party, argued to equalize the two rates. Additionally, CME ignores that, as Undertaking J21.3 shows, while discount rates are one driver of differences between the ARO and ONFA funding obligation, there is a substantial difference in the opposite

[114] OPG understands CME means to request that the OEB increase, not reduce, the ARO discount rate to match the ONFA rate, as the ARO discount rate is lower than the ONFA rate.

[115] As noted in Ex. N1-1-1, p. 16, when the underlying undiscounted cash flows decrease, OPG uses the weighted average discount rate of the existing ARO balance to determine the change in the ARO, in accordance with US GAAP.

direction, because the ONFA includes funding for future wastes not yet generated that are not included in the ARO.

9.1.5 The OEB-Approved Methodology is Superior to a Cash Method

OPG submits that the existing OEB-approved methodology is superior to the cash model proposed by intervenors and better meets established regulatory principles as discussed below. OPG has organized the discussion based on the principles enumerated by the OEB at page 3 of its recently issued Report on Pension and Other-Post Employment Benefits (OPEBs) Costs (EB-2015-0040) and added a discussion of transition issues as discussed at page 9 of the EB-2015-0040 Report. OPG observes that there are some similarities between the issues examined in that consultation and nuclear liabilities issues that intervenors raise in this proceeding.

Minimizing Intergenerational Inequity / Providing Value to Customers: Intergenerational inequity arises when costs incurred in providing service to a generation of ratepayers in one period are paid in a different (past or future) period by a different generation of ratepayers.

As discussed above, the existing recovery methodology for nuclear liabilities attributes the costs of decommissioning the nuclear stations and long-term management of nuclear waste over the station's life. Costs that are considered to be fixed in nature are amortized through depreciation expense and those costs that are considered to vary with output are accounted for as part of fuel costs or, to a lesser extent, operating OM&A (Ex. C2-1-2, p. 7).[116] This allows these costs to be matched to the period over which the customers receive value through consumption of electricity, supporting intergenerational equity.

In contrast, for the ONFA-funded portion of the liabilities, a cash-based methodology would over-recover from customers in earlier years and under-recover in later years, due to the front-loaded nature of the ONFA funding requirements. This applies to both the initial funding liability and subsequent changes in the funding liability during the station's life (due to a change in assumptions or baseline cost estimates) – customers consuming electricity immediately following a change during the station's life may be charged significantly higher amounts under an ONFA-based methodology than future customers, even though both sets of customers

[116] In the same vein, OEB staff note that "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" (OEB staff argument, p. 131).

should be equally responsible for end-of-life costs. This intergenerational inequity is reduced under the existing methodology, as the change in the liabilities would generally be amortized into costs over the proper remaining life of the station.

For internally-funded expenditures, a pay-as-you-go methodology would concentrate recovery in the year of the cash outlay, likely to be different than the period in which the corresponding waste was actually produced through the electricity generation process. For example, the expenditures for used fuel operations in a given year are for work performed handling and transferring fuel bundles that were consumed 10 or more years earlier.[117] The customer paying for these costs in the current year will receive little or no value from these expenditures since the electricity was produced 10 years earlier. This is similar to the pay-as-you-go approach to OPEBs where the costs being paid out bear little relationship to the cost obligation being incurred based on work in the current year. Intergenerational inequity would ensue from this approach.

Fairness: A cash-based methodology would be unfair both to customers and to OPG and its Shareholder. From a customer's perspective, a fair recovery methodology should be linked to "cost causation" and appropriately and predictably match recovery of the costs to the periods in which the customers receive the benefit of services. The cash-based method fails to provide such matching. Additionally, recovery of internally funded expenditures on a cash basis may result in a potential "windfall" for OPG because the customers could end up paying again for the portion of these costs that were previously accrued and fully or partially recovered through depreciation expense or variable costs.[118] This would be unfair to customers.

From a utility's perspective, a fair methodology allows for recovery of the necessary costs incurred to deliver a service, on a reasonably timely basis. Due to the front-end loading of the ONFA, adopting the cash-based methodology at this time would effectively deprive OPG of an ability to recover its fully incurred costs related to the nuclear liabilities, which are material. As

[117] As described in EB-2010-0008, Ex. C2-1-1, p. 2, used fuel bundles are temporarily stored in water-filled pools at the nuclear stations for a "cooling-off" period of at least ten years, during which time their radioactivity is substantially reduced. Subsequently, used fuel is transferred to above-ground concrete canisters for storage at each nuclear station site.

[118] This potential concern, although very difficult to quantify, is similar in nature to the potential "windfall" referenced in EB-2015-0040, the Report of the OEB, Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs, p. 9.

discussed above, cash outlays have significantly exceeded amounts recovered by OPG since April 1, 2005. In addition, as also noted above, there were substantial contributions by OPG and the Province between 2003 and 2005. Switching to a cash-based methodology at this point in the funding lifecycle would not allow rate recoveries to "catch up" to the cumulative amounts expended.

If a cash-based methodology were to be adopted going forward, OPG would experience an economic loss. The adverse financial consequences to OPG and its shareholder would include material reductions in the company's revenues and, as a result, net income, decreases in cash flow and pressure on financial metrics. Said differently, depreciation expense and variable costs will remain on OPG's income statement, but the company's revenues will not suffice to cover these costs over the remaining life of the station.

The anticipated net of tax reduction to revenue over the IR term would be $336M. This is the difference between the after-tax amounts to be recovered under the existing methodology and the after-tax amounts forecast to be expended over the 2017-2021 period (for both prescribed and Bruce facilities), per Ex. J20.8. OPG submits such an outcome would be an unfair. Contrary to the implication of LMPA's submission, it is unreasonable to expect OPG to implement over $300M of offsetting savings over the IR period, in addition to meeting a challenging business plan, achieving the stretch factors and absorbing any other financial consequences arising from the OEB's decision in this proceeding.

Moreover, the adverse financial impacts would not be limited to this test period. For example, the undepreciated ARC at the end of 2021 would be charged to depreciation expense, but not recovered in the post-2021 period under a cash-based methodology. That balance is estimated at about $2.9B for both Bruce and prescribed facilities.[119]

Minimizing Rate Volatility / Appropriate Allocation of Risk: The existing methodology for the prescribed facilities yields more stable revenue requirements than the cash method.[120]

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[119] Estimated based on $238M for the prescribed facilities + $2,656M for the Bruce facilities. The prescribed facilities figure is derived from Ex. J21.1, Attachment 2: Table 5, line 34, col. (e) minus Table 7, line 41, col. (d). The Bruce facilities figure is from Ex. N1-1-1, Table 4, line 22, col. (e).

[120] For the Bruce facilities, it is much more difficult to assess which of the recovery methodologies (cash-based or existing) would lead to greater volatility or relative allocation of risk.

Among other things, this greater stability for the prescribed facilities is supported by the fact that periodic revaluations of the liability due to changes in assumptions or underlying cost estimates would be amortized over the remaining station life, not over a potentially shorter period pursuant to the ONFA.

Moreover, as discussed in Ex. C2-1-2, future contribution levels are not just a function of changes in the underlying cost estimates, but also future fluctuations in market performance that impact earnings on the funds. Should the funds under-perform relative to the target rate, higher contributions may be required at the time of the next ONFA reference plan. Hence, under the cash methodology for the prescribed facilities, ratepayers would be subject to the risk of future segregated fund performance. Finally, yearly cash outlays for internally funded expenditures will be inherently more uneven than the relatively predictable annual depreciation expense and variable costs.

OPG also wishes to emphasize, as OEB staff recognize at page 131 of their submission, that the fully funded status of the segregated funds at year-end 2016 cannot be taken as indicative of future funding requirements based on subsequent ONFA reference plans (Ex. C2-1-2, p. 6). As Charts 3 and 4 in that exhibit show, historically there have been differences, in both directions, between amounts recovered and amounts expended. And while the 2017-2021 cash amounts are currently expected to be lower than those under the existing recovery methodology, it is not difficult to envision future circumstances at the time of the next ONFA reference plan, or a subsequent one, that could materially increase ONFA funding requirements (particularly considering that the UFF was marginally over-funded at year-end 2016, by less than 1%) (AIC, p. 137).

In a given period, many factors can affect the funded status and the relative difference between cash amounts and amounts pursuant to the existing methodology, including but not limited to:

- market performance;[121]

[121] In general, the long-term nature of the required funding for nuclear waste management and decommissioning naturally lends itself to periods of under-earning or over-earning relative to the long-term target rate of return, as noted by the OEB in the EB-2013-0321 Decision with Reasons (p. 110). This could result in significant fluctuations in the funded status of the funds over time. For example, the relatively strong overall performance of the funds from inception could be followed by a period of future under-performance.

- changes in liability estimates;
- conservative ONFA funding rules;
- requirement to fund costs related to waste not yet generated;
- asset investment decisions (made jointly with the Province);
- differences between ONFA and accounting discount rates;
- changes in assumed timing or strategies for permanent long-term disposal of wastes that can increase internally funded expenditures for interim storage of the wastes; and
- changes in the consumer price index (Ontario) which forms the basis for the Province's rate of return guarantee for the first 2.23 million bundles' portion of the UFF.

CCC appears to misunderstand the above point made in Ex. C2-1-2. At page 34 of its submission, CCC incorrectly states that volatility will necessarily be reduced. OPG does not fully follow CCC's submission since it appears to state the self-evident proposition that if volatility is measured as the difference between amounts paid out and collected, it would be reduced if amounts collected were set equal to the amounts paid out. OPG's actual point is that the cash-based methodology for the nuclear liabilities (in part, similar to the registered pension plans[122]) may not consistently yield a fully funded status or lower recovery amounts for ratepayers than the existing methodology, just because it is forecast to do so for the current five-year period. As OPG stated in Ex. C2-1-2, pages 26-27, "the revenue requirement methodology for the nuclear liabilities should reflect their long-term nature, not a point in time funded status of the monies set aside to discharge these obligations."

Transparency: OPG believes that the ONFA-based cash methodology would be inherently less transparent than the existing accounting-based methodology. The ONFA is a 200-page bilateral contract between OPG and the Province (Ex. L-8.1-15 SEC-091). It was never intended to be a ratemaking tool, and can be amended if the two parties agree.[123] While it sets

[122] ONFA funding is generally more front-loaded than registered pension plan funding. However, in either case, there are a host of factors that make it extremely difficult, if not impossible, to predict the direction of a particular future period's "cash-to-accounting" variance.

[123] SEC's argument is that the Province, notwithstanding or perhaps because of the nature of the arrangement, meant to use it to indicate an appropriate basis for recovering nuclear liabilities costs from ratepayers. If this were the case, O. Reg. 53/05 would have contained explicit language clearly requiring the OEB to follow this basis. Since it does not, the OEB determined it was free to establish the adopted recovery methodology based on applicable ratemaking principles.

out a detailed set of funding rules and calculations that must be followed, it periodically requires interpretation by OPG and the Province.[124] In the past, the ONFA also has required OPG to make special contributions to the segregated funds.[125]As the OEB noted in the EB-2031-0321 Decision (p. 110), "[t]he Board has no authority over the segregated funds or the reference plan for nuclear liabilities established by the Ontario Nuclear Funds Agreement".

The existing methodology better aligns with the financial accounting treatment of these costs and with sound rate-making principles. Accounting values are determined in accordance with a common set of accounting rules, developed by recognized accounting standard-setting organizations through a defined, transparent, participative process, and are reflected in OPG's publicly available audited financial statements. OPG's financial accounting practices in relation to nuclear liabilities have been described in evidence and parties have been able to study and test them throughout the years. No substantive issues have been identified in prior proceedings.

Transition Issues: Continuing with the existing methodology avoids potential complexities associated with transition to a cash-based methodology. As the OEB stated in the EB-2015-0040 Report at page 9, "[t]he issues raised by transitioning between recovery methods may be serious and difficult to resolve fairly,…" OPG submits that this statement applies with even greater force here than it does for pension and OPEB costs. As demonstrated above, the pre-funding of nuclear liabilities in the earlier years is measured in billions of dollars, as are the likely longer-term financial impacts on OPG.

CCC and CME attempt to downplay the transition issue. The core of their argument is that OPG would not be harmed if the transition were to take place at this time because amounts collected from ratepayers since April 1, 2008 are not greatly different from amounts paid out as ONFA contributions and internally funded expenditures over that period (CME paras. 323, CCC, pp. 30-31). With respect, OPG submits that this is too narrow a view in this particular

[124] SEC's argument is that the Province, notwithstanding or perhaps because of the nature of the arrangement, meant to use it to indicate an appropriate basis for recovering nuclear liabilities costs from ratepayers. If this were the case, O. Reg. 53/05 would have contained explicit language clearly requiring the OEB to follow this basis. Since it does not, the OEB determined it was free to establish the recovery methodology that it did based on applicable ratemaking principles.
[125] As noted at Ex. C2-1-2, p.11, in addition to regular quarterly contributions, OPG was required to make a special one-time payment of $334M into the UFF in 2007, which further accelerated the funding of the underlying liabilities.

case, given the implications. At issue are decades-long obligations involving tens of billions of dollars. In this circumstance, arbitrarily restricting the OEB's focus to a small slice of the relevant time period would be a mistake.

OPG also observes that the significant financial impacts arising from a go-forward change to a cash-based methodology are inconsistent with the overall thrust of O. Reg. 53/05, which is to keep OPG whole on the issue of nuclear liabilities.

9.1.6 OEB Staff's Requested Study

OEB staff submit that the OEB direct OPG to file, in its next cost-based nuclear payment amounts application, a study of "the various costs recovery methodologies for nuclear liabilities including the provision of the underlying estimates and the assumptions used", including "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 argument, p. 132). This request is rooted in OEB staff's concerns that new risks exist that may not have been contemplated at the time the original recovery methodologies were established (OEB staff argument, p. 131). The risk that OEB staff identifies is the fact that the 2017-2021 ONFA Reference Plan represents the first time that OPG is not required to make any funding contribution payments to both the UFF and the DF (*Id.*).

OPG does not see a need for the requested study. First, for the Bruce facilities, OPG struggles to see the utility of a study given that the existing methodology was established by clear reference to the requirements of O. Reg. 53/05 consistent with the broader issue of the appropriate basis for the determination of Bruce Lease net revenues. As outlined in Ex. C2-1-2 (pp. 16, 27, 28) and the AIC (pp. 140-141), and as discussed above, the current GAPP-based methodology arose from the application of O. Reg. 53/05 requirements and the fact that the Bruce facilities are not regulated assets. Those circumstances have not changed and the GAAP-based treatment of the Bruce facilities was most recently reaffirmed in the EB-2013-0321 Decision with Reasons (p. 107).

Second, OPG disagrees that the fact that both the UFF and DF were in an overfunded position as of year-end 2016, and no contributions are currently required, is a basis for the OEB to direct a study of alternative recovery methodologies. This change is more a difference of degree than of kind relative to the conditions in EB-2007-0905. As discussed above, while the UFF has not overfunded, the DF was overfunded at the time the OEB established the nuclear liabilities methodology in the EB-2007-0905, as well as in subsequent proceedings. This fact is specifically adverted to in the OEB's EB-2007-0905 decision at page 66 and in the EB-2013-0321 Decision with Reasons at page 109.

For these reasons, OPG respectfully submits that there is no need to direct OPG to undertake the requested study. Nevertheless, OPG does not oppose the request for a study if the OEB views it as valuable.

9.2 Issue 8.2

Primary: Is the revenue requirement impact of the nuclear liabilities appropriately determined?

Please see Issue 8.1 (Section 9.1).

10.0 DEFERRAL AND VARIANCE ACCOUNTS

10.1 Issue 9.1

Primary: Is the nature or type of costs recorded in the deferral and variance accounts appropriate?

This issue is partially settled. In the OEB-approved settlement agreement (Ex. O-1-1, p. 12-13; Tr. Vol. 9, p. 1), parties agreed that the nature and type of costs recorded by OPG were appropriate on the basis of OPG's evidence, except for the CRVA (Nuclear), Nuclear Liability Deferral Account, and Bruce Lease Net Revenues Variance Account.

No party made submissions on the nature or types of costs recorded in OPG's existing D&V account. Parties' submissions on the newly proposed D&V accounts are addressed under Issue 9.8 (Section 10.8).

OPG submits that the nature and type of costs recorded in all of OPG's D&V accounts are appropriate and should be approved by the OEB.

While not objecting to the nature or type of costs recorded in the above noted unsettled accounts, OEB staff did propose to prospectively expand the scope of the Income and Other

Taxes Variance Account to include a true-up for actual SR&ED ITCs. As outlined in Issue 6.10 (Section 7.10), OPG disagrees with this proposal.

10.2 Issue 9.2

Primary: Are the methodologies for recording costs in the deferral and variance accounts appropriate?

This issue is partially settled. In the OEB-approved settlement agreement (Tr. Vol. 9, p. 1; Ex. O-1-1, pp. 12-13), parties agreed that the nature and type of costs recorded by OPG were appropriate on the basis of OPG's evidence, except for the CRVA (Nuclear), Nuclear Liability Deferral Account, and Bruce Lease Net Revenues Variance Account.

The CRVA received considerable attention during this proceeding. OEB staff, CCC, CME, GEC, LPMA, QMA, and SEC made submissions in relation to the operation of the account. These submissions can be grouped into the following categories: (i) the level of reporting detail required for DRP in terms of the CRVA; (ii) the appropriateness of OPG's proposed approach to the CRVA for hydroelectric under IRM; (iii) applying the hydroelectric methodology to DRP and Nuclear Operations; and (iv) deferral of PEO costs. The first and fourth of these categories are discussed above in Issues 4.5 (Sections 5.5) and Issue 6.5 (Section 7.5), respectively. The remaining two are discussed below, following a discussion of the purpose of the CRVA.

OPG addresses the implications on the Nuclear Liability Deferral Account and the Bruce Lease Net Revenues Variance Account of parties' submissions under Issues 7.2, 8.1 and 8.2 (Sections 8.4-9.2). No separate submissions on these accounts were received.

10.2.1 Purpose of the CRVA

The CRVA was originally approved by the OEB in EB-2007-0905 and has been approved in each subsequent application. As described in the AIC at page 165, the CRVA was established to implement the requirements of O. Reg. 53/05 and, in particular, section 6(2)4 that requires the OEB to "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 [prescribed] generation facility…" The OEB established the CRVA with the specific purpose of recording, for costs that meet this definition, variances from amounts included in the approved cost-based revenue requirement. The goal was to ensure that OPG recovers its prudently incurred costs but not more.

The CRVA applies to both OPG's prescribed hydroelectric and nuclear facilities.

OEB staff and a number of intervenors propose to use the CRVA for purposes for which it was never intended. These include a deferral account for DRP and PEO costs, an asymmetrical variance account for nuclear capital project portfolio in-service additions, and a mechanism to adjust the RSDA carrying charges prescribed by O. Reg. 53/05. As OPG explains below and elsewhere in this submission, none of these proposals are appropriate.

The CRVA has never been, nor is it mandated by O. Reg. 53/05 to be, a general purpose revenue requirement adjustment account, floating over all of OPG's OEB-approved costs.

10.2.2 Operation of the Hydroelectric CRVA under Incentive Regulation

With one limited exception, OEB staff agree with OPG's proposal for determining variances to be recorded to the CRVA during the IR term, including the process by which those amounts would be recorded. OEB staff also agree with OPG's approach to ensure that it does not recover the CRVA eligible costs twice. For their part, SEC, LPMA, and CCC also agree, generally, with OPG's proposed approach.[126] They argue however that the threshold used to evaluate eligibility to clear balances in the hydroelectric CRVA account should be increased.[127] CCC also adopts OEB staff's argument with respect to the CRVA reference amount, discussed immediately below.

10.2.3 Hydroelectric CRVA Reference Amount

OEB staff and CCC object that OPG has not proposed to adjust the CRVA related revenue requirement impact of 2014 and 2015 in-service additions reflected in current hydroelectric payment amounts by the I-X formula.[128] This is the $0.9M described by OEB staff as the reference amount and the amount OPG annually proposes to credit to customers in the CRVA until rebasing.[129] Their objection is inconsistent with IRM.

[126] SEC argument, para 10.7.19; LPMA argument, p. 34; CCC argument, p. 41.
[127] SEC argument, para. 10.7.18; LPMA argument, p. 34, CCC argument, p. 41.
[128] OEB staff argument, p. 162; CCC argument, p. 41.
[129] OEB staff argument, p. 160.

The issue is dealt with in Ex. L-9.2-1 Staff-213. Rate-setting through a price-cap index is intended to decouple payments and costs. Escalating any reference amount, CRVA related or otherwise, used to establish rates maintains the link between costs and revenues and is therefore fundamentally at odds with a core principle of IRM. By way of example, the OEB specifically acknowledges that the pension and OPEB amounts that utilities have embedded are not expected to escalate during an IR term. OPG sees no distinction between this approach to pension and OPEB amounts and this referenced amount.[130] OPG is not aware of any OEB decision in which it has required reference amounts to be escalated by the price-cap index.

10.2.4 Hydroelectric CRVA Threshold

OEB staff agree with OPG's threshold used to evaluate eligibility to clear balances in the hydroelectric CRVA. SEC, LPMA, and CCC suggest that the threshold should be increased. LPMA and CCC support the use of the ICM threshold test (LPMA argument, p. 34; CCC argument, p. 41), whereas SEC proposes to set the funding threshold at $1B (SEC argument, para. 10.7.18). None of these proposals withstands scrutiny.

The comparison between the CRVA and the ICM applicable to an electric LDC is misplaced. As OPG explained:

> [T]he environment that the LDCs are under is somewhat different in that they're in a rate base growth -- a growing rate base environment which is different to ours. They've [LDCs have] an ability to increase customer base, their revenues, which is different to ours.
>
> And I think probably most fundamentally, the age of their assets is quite a bit different than OPG's.
>
> So the rate base, the depreciation ratio for LDCs, for example, is about 25 to 1, whereas in our case it's more like 55.
>
> So I think some of the arguments that the LDCs had made through the ICM consultation was that because of the long life of their assets that the cost to replace those assets that are covered by depreciation is much greater than the cost that they expended originally. In our case that's significantly exacerbated.

[130] EB-2015-0040 Report of the Board on the Regulatory Treatment of Pension and Other Post-employment Benefits Costs.

> …We believe that an objective reflection of what capital is covered in our IRM is the depreciation amount. In the context of the CRVA, which is a nuance relevant to OPG, there is no materiality threshold for when we get those costs back provided that they're prudently incurred.
>
> So the next dollar past what is funded within our IRM would be recoverable as per the regulation. So there are a number of significant differences to our situation and our understanding of that ICM calculation. (Tr. Vol. 21, pp. 38-39).

With respect to SEC's proposal, it significantly overstates OPG cash flow available to fund capital expenditures during the IR term. SEC erroneously includes both the return of (depreciation) and return on (ROE and cost of debt) capital. ROE and costs of debt are not sources of funding available for reinvestment but rather are financing costs. In OPG's submission, as outlined in Ex. H1-1-2, the depreciation expense embedded in base payment amounts represents the appropriate threshold. OEB staff agree (OEB staff argument, pp. 162-163).

10.2.5 Operation of the Nuclear CRVA

The operation of the CRVA has never been controversial. As OEB staff concede in their submission at page 160, the operation of the CRVA has been "relatively straightforward" under the OEB's historic cost of service approach to setting OPG payment amounts.

Despite this concession, OEB staff and CCC argue that the operation of the nuclear CRVA should be fundamentally altered (OEB staff argument, pp. 64-65; CCC argument, pp. 46-47). They argue that recovery of amounts recorded in the CRVA should only be permitted if amounts were prudently incurred <u>and</u> these amounts are not offset by any variance in non-CRVA nuclear capital in-service amounts. In other words, these submissions propose to subject non-CRVA eligible amounts to CRVA treatment asymmetrically in favour of ratepayers. OPG argues that these submissions are unfounded and should be rejected.

A key basis of CCC and OEB staff's submissions appears to be OPG's hydroelectric CRVA proposal. The comparison is wrong as a different regulatory framework applies to each of the businesses.

On the hydroelectric side, OPG has proposed a price-cap index that incorporates the elements and approach established by the OEB for Fourth Generation IR Methodology ("4GIRM"). Under this approach, OPG will manage its hydro business within the scope of funding provided by the index.

The Filing Guidelines established by the OEB do not require OPG to seek approval of a detailed capital plan covering the five-year hydroelectric IR term. In this context, it was necessary for OPG to develop the hydroelectric CRVA proposal detailed in Ex. H1-1-2. As CCC puts it succinctly in their own submission, "[t]he concern in the proceeding was that mixing IRM with cost of service elements could result in double counting" (CCC argument, p. 41).

The same circumstances do not apply to nuclear. Consistent with OEB policy, OPG has proposed a Custom IR framework underpinned by a five-year capital plan that clearly identifies specific projects which will be subject to CRVA treatment. No party has raised any concerns about whether these projects are CRVA eligible.[131]

As in past cost of service proceedings, the OEB is being asked to approve, on a forecast basis, the revenue requirement associated with OPG's identified planned CRVA and non-CRVA eligible capital projects over the IR term. Thus there is no reason why the nuclear CRVA should operate differently than it has in the past.

The fallacy of the approach proposed by OEB staff and CCC is that it has no logical limit. For example, it could be used to extend the CRVA to include variances in fuel costs (or any other expense) or to argue that any overspending on capital should be balanced against any under spending on OM&A. Taken to the extreme, it could be used to true-up any aspect or portion of the revenue requirement. Surely, this is neither the intent of the OEB's previous decisions nor the intent of O. Reg. 53/05.

As a practical matter, of the projects identified as subject to the CRVA over the 2017-2021 period, DRP and, to a lesser extent, Pickering Extended Operation enabling costs make up the lion's share of eligible expenditures (AIC, pp. 22-24). These are defined, high-priority and high-profile initiatives, with approved budgets and schedules, that are aimed at extending the

[131] OEB staff agree that the identified projects meet the requirements of section 6(2) para. 4 of O. Reg. 53/05 and therefore should be subject to CRVA treatment (OEB staff argument, pp. 34-35).

operation of OPG's two nuclear facilities and that have been debated at great length in this proceeding. The likelihood of any material trade-off or co-mingling of this work and the nuclear capital project portfolio that OEB staff and CCC may be attempting to "guard against" is exceedingly small. In any event, as explained at length in Issue 4.5 (Section 5.5), OPG submits that it has fully supported its capital Nuclear Operations capital plan and addressed the parties' concerns with the plan's achievability over the IR term.

In OPG's submission what parties' proposal really amounts to is an asymmetrical variance account for nuclear capital in-service amounts. OPG has obvious, significant concerns with this approach:

1. It is directionally at odds with the notion that IRM and Custom IRM are meant to move a utility toward greater de-coupling of costs and revenues. IRM is aimed at encouraging applicants to find efficiencies and not at creating more true-up mechanisms.

2. There is no evidence that the proposal would meet the OEB's criteria for variance account treatment, and OPG submits that it would not.

3. Even if the OEB were to contemplate such a true-up mechanism, there is no fair reason for making this true-up asymmetrical – it should operate symmetrically like any variance account.

4. It is impractical as it would require a detailed, project-by-project review of variances across the entire nuclear project portfolio, in addition to the limited number of CRVA-eligible projects. Such a review would be significantly complicated by the fact that, as discussed in Issue 4.5 (Section 5.5), projects can be deferred, delayed, advanced or replaced over time (and some forecast in-service amounts are for projects yet to be identified). Conducting the necessary analysis to support the expanded scope of the CRVA over a five-year period would be a significant undertaking.

OEB staff also submit that OPG should not be entitled to recover any prudently incurred DRP related overspend where OPG's actual ROE exceeds the OEB-allowed level. OEB staff propose that any overearnings be credited in the CRVA against DRP-related prudent cost overruns (OEB staff argument, p. 65).

There is no proper basis for OEB staff's position. They acknowledge that the posited scenario is "extremely unlikely to occur" (OEB staff argument, p. 64). Further, under OEB staff's proposal OPG would effectively be denied recovery of a portion of its prudently incurred DRP costs, which is contrary to O. Reg. 53/05. OPG has included an off-ramp proposal that directly addresses a situation (which has never occurred) where OPG over earns its allowed ROE. As discussed in relation to Issue 9.7 (Section 10.7), no party objected to OPG's proposal. As O. Reg. 53/05 entitles OPG to recover its prudently incurred costs in respect of the DRP, and OPG's off-ramp proposal addresses the potential for overearnings beyond the usual 300 basis point threshold, OEB's staff's position should be denied.

10.2.6 Rate Smoothing and the CRVA

OEB staff has proposed that the OEB approve DRP spending at a P37 confidence level in order to create a "natural smoothing effect", stating that any revenue requirement impacts will be captured in the CRVA and presumably cleared after 2021 (OEB staff argument, p. 178). This proposal is misplaced.

Using the CRVA account to implement rate smoothing is inconsistent with the intention of the CRVA and RSDA as provided for in O. Reg. 53/05. The proposal could also result in unintended consequences, in that it could result in significant CRVA balances and thereby complicate rate smoothing in the next nuclear cost based application.

At the hearing, OPG responded to a series of questions concerning the relationship of the CRVA, rate smoothing, and the DRP. As Mr. Fralick testified:

> …at the heart of the intent of the CRVA is for [OPG] to make accurate forecast of what we think projects are going to cost, and then if those projects deviate we're required to reflect those variances, capture the variances in the CRVA.
>
> So that's the way the regulation stipulates it, so I don't see how we would be able to trade them within these different accounts. That's not the intent of the CRVA. (Tr. Vol. 22, p. 35, lines 16-23).

The proposal to use the CRVA to implement rate smoothing further contradicts the requirements of O. Reg. 53/05. In brief, section 5.5(1) requires that deferred portions of the revenue requirement be recorded in the RSDA.

In addition to being inconsistent with the intention of both the RSDA and the CRVA, OEB staff's proposal could result in outcomes for customers that are misaligned with the broader rate smoothing objective of O. Reg. 53/05. This would be apparent in OPG's next cost-based nuclear payment amounts application. If the final DRP cost matches the P90 forecast that OPG believes is appropriate for rate-setting purpose, but the revenue requirement was set at the

P37 level, the difference would be eligible for CRVA treatment. The recovery of the revenue requirement of this difference would place added pressure on rate smoothing from 2022 - 2026, at a time when pressures on nuclear payment amounts are expected to be greater than in the 2017-2021 period.[132]

Effectively, OEB staff propose to use the CRVA as a deferral account for a portion of DRP costs in order to bypass the rate smoothing mechanism laid out in O. Reg. 53/05 and, as they state, to implement "a cheaper (for ratepayers) smoothing mechanism than the RSDA." (OEB staff argument, p. 178). OPG submits that the OEB should reject this notion. Had the Government intended to allow rate smoothing to be undertaken through means other than the Rate Smoothing Deferral Account, it would not have set out detailed parameters around that account, such as the interest rate on the account balance, in the regulation.

OEB staff's proposal is aimed at leveraging the difference in the interest rate charged on the CRVA (short-term, low interest rate prescribed by the OEB's policy) compared to the RSDA (compounded interest rate based on OPG's long-term debt cost). During the hearing, OPG specifically observed that, should a scenario arise where material amounts deferred in the CRVA are being cleared over extended periods of time, it may be appropriate to consider whether the currently applicable short-term rate would remain appropriate in the circumstances:

> But, you know, we've had accounts -- most accounts, particularly interest-bearing accounts, cleared over relatively short periods of time, over a few years if memory serves. I think if we were to find ourselves in a scenario where the CRVA was -- it was on the table to clear the CRVA balance over a much longer period of time, I would just note that we would certainly turn our mind to an appropriate interest rate it should attract in that context. I'm not sure that 1.1 percent for an account that's cleared over an extended period of time would be our proposal. I recognize, of course, the Board's policy is in place. But certainly we would turn our mind to that at that time. (Tr. Vol. 20, p. 91, lines 13-25).

[132] OPG provided a preliminary view of the revenue requirement and production forecasts from 2022-2036 for the purpose of evaluating the rate smoothing proposal (Ex. N3-1-1, Attachment 2, Table 19). Production is expected to be lower after 2021 (as a result of DRP outages and end of Pickering commercial operations), bottoming at 19TWh in 2025, or approximately half of the forecasted production for 2017. This will place significant pressure on nuclear payment amounts in the post-2021 period. OEB staff's proposal will add to this pressure by effectively deferring a portion of the revenue requirement from this rate-setting term to the next one.

For its part, CCC argues the CRVA can be used as a substitute for entries that under the regulation should be made to the RSDA. As CCC puts it, a scenario may arise where “the Board may approve a significant amount of deferred revenue for tracking in the RSDA for a particular year, while in reality, for that same year, OPG may end up tracking a material amount of revenue requirement in the CRVA as a credit to rate payers.” (CCC argument, p. 49). CCC proposes to track credits to the CRVA in the RSDA instead. CCC’s approach is wrong in law based on the clear terms of the regulation.

In any event, OPG submits that while there almost certainly will be some entries into the CRVA over the course of the 2017-2021 period, the RSDA is not the appropriate account in which to track those variances. The CRVA captures the revenue requirement impact of variances between OEB approved and actual in-service capital additions, and non-capital costs, on CRVA eligible expenditures. The variances that accumulate in this account relate to specific projects, and have been cleared over relatively short periods of time. It is appropriate for such variances to attract interest at the OEB’s prescribed interest rate for D&V accounts.

The RSDA, on the other hand, captures the annual deferral of revenue requirement as determined by the OEB. This deferred amount is part of the overall revenue requirement, but is not attributable to any specific component of the revenue requirement or to any specific project (CRVA eligible or otherwise). Under CCC’s proposal, part of the deferred revenue requirement the OEB determines in this Application would be attributed differences in CRVA eligible spending that may happen several years down the road. In OPG’s submission this distorts the intention of the CRVA and RSDA accounts and should be rejected by the OEB.

10.3 Issue 9.3

Secondary: Are the balances for recovery in each of the deferral and variance accounts appropriate?

This issue is partially settled. In the OEB-approved settlement agreement (Tr. Vol. 9, p. 1; Ex. O-1-1, pp. 13-14), parties agreed that the December 31, 2015 balances for recovery in each of the D&V accounts were appropriate on the basis of OPG’s evidence, except for the CRVA (Nuclear), Nuclear Liability Deferral Account, the Bruce Lease Net Revenues Variance Account, and the Pension & OPEB Cash Versus Accrual Differential Deferral Account (which is subject to the OEB’s generic proceeding in EB-2015-0040).

OEB staff did not object to the nature or type of costs recorded in the unsettled accounts noted above. OEB staff's submissions agree with OPG's proposal given that the forecasted cash and forecast accrual amounts for pension and OPEB costs included in this Application will have gone through a prudence review (OEB staff argument, p. 134). In line with this, OPG submits that as in the EB-2013-0321 Decision with Reasons at page 92, these amounts should not be subject to a future prudence review beyond this Application, including upon future clearance of the Pension & OPEB Cash Versus Accrual Differential Deferral Account. VECC supports the position taken by OEB staff. No other submissions were received on this issue.

OPG submits that the balances proposed for recovery in each of the D&V accounts are appropriate and should be approved by the OEB. OPG further submits that the balances in the Pension & OPEB Cash Versus Accrual Differential Deferral Account should not be subject to any further future prudence review.

10.4 Issue 9.4

Secondary: Are the proposed disposition amounts appropriate?

OPG proposes to clear the audited December 31, 2015 balances in the D&V accounts as provided in Ex. H1-1-1, Table 1, consistent with the OEB's expectation that "all accounts should be reviewed and disposed of in a cost of service proceeding unless there is a compelling reason to not do so." (EB-2013-0321 Decision with Reasons, p. 125). No concerns were raised by OEB staff or intervenors with respect to the amounts proposed for disposition.

10.5 Issue 9.5

Primary: Is the disposition methodology appropriate?

OPG submits that the proposed disposition methodology is appropriate. Under this methodology, OPG proposes to calculate separate hydroelectric and nuclear payment riders for the period from January 1, 2017 to December 31, 2018 in the form of $/MWh rates consistent with the OEB's decisions and Payment Amounts Orders in EB-2012-0002, EB-2010-0008, EB-2013-0321, and EB-2014-0370. OEB staff has not raised any concerns relating to the disposition methodology for the December 31, 2015 year end balances.

One issue OEB staff has raised is the timing for the resumption of accrual accounting for Pension and OPEB costs arising from the OEB's recent report in EB-2015-0040.[133] As OEB staff states in section 9.2 of their argument, the transition could be considered as part of the mid-term review, provided it is approved by the OEB. OPG's view is that the timing for the resumption of accrual accounting for Pension and OPEB costs, and the disposition of OPG's Pension & OPEB Cash Versus Accrual Differential Deferral Account balances should be based on both regulatory principles and regulatory efficiency. On June 22, 2017 OPG will file comments in response to the OEB's report under EB-2015-0040, detailing how an expedient resumption of accrual accounting is consistent with the principles of minimizing intergenerational equity, fairness, and transparency. As a matter of regulatory efficiency OPG submits that it would be appropriate to clear the Pension & OPEB Cash Versus Accrual Differential Deferral Account at the same time as its application for 2018 hydroelectric payment amounts.

As noted by OPG in its EB-2015-0040 submission, continued recognition of the amounts recorded in the Pension & OPEB Cash Versus Accrual Differential Deferral Account is dependent on OPG beginning to recover those amounts within five years from the time that they were incurred.[134] For example, amounts recorded during November 2014 must begin to be recovered no later than November 2019 and must be fully recovered within 20 years of November 2014. Failing this, OPG will be required to write off the regulatory asset for these amounts. As such, OPG will be required to file an application to review the disposition of the Pension & OPEB Cash Versus Accrual Differential Deferral Account in short order.

In OPG's submission it would be appropriate to review the disposition of all other account balances as part of the mid-term review (see also Issue 11.5, Section 12.7).

10.6 Issue 9.6

Secondary: Is the proposed continuation of deferral and variance accounts appropriate?

There is an agreement to settle this issue (Ex. O-1-1, pp. 14-15; Tr. Vol. 9, p. 1).

[133] EB-2015-0040, Report of the Ontario Energy Board, Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs, May 18, 2017.
[134] EB-2015-0040, Consultation on the Regulatory Treatment of Pensions and Other Post-Employment Benefit Costs, OPG Submission dated September 22, 2016, p. 15, footnote 20.

10.7 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?

Parties have generally accepted that the rate smoothing deferral account is consistent with O. Reg. 53/05 and is appropriate. A number of submissions were received on the mechanics of rate smoothing which are addressed in Issue 11.6 (Section 12.8).

10.8 Issue 9.8

Primary: Should any newly proposed deferral and variance accounts be approved by the OEB?

As set out in detail in Ex. H1-1-1, Section 6, OPG seeks approval of four new D&V accounts. OPG submits that each account is required by regulation or appropriately addresses a proposed change in regulatory approach. Each proposed account satisfies the OEB's D&V account eligibility criteria of causation, materiality, and prudence. OPG asks that the proposed accounts be established.[135]

10.8.1 Rate Smoothing Deferral Account

The proposed new RSDA is mandated by O. Reg. 53/05 as amended and should be approved by the OEB. Parties have generally accepted that the rate smoothing deferral account is consistent with O. Reg. 53/05 and is appropriate. A number of submissions were received on the mechanics of rate smoothing. These are addressed in Issue 11.6 (Section 12.8).

10.8.2 Mid-term Nuclear Production Variance Account

This account is discussed in Issue 11.5 (Section 12.7).

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[135] OEB staff have requested that OPG provide a draft accounting order for each of the requested accounts during the draft rate order process (OEB staff argument, p. 136). OPG believes that it has already provided the OEB with the information that would be otherwise contained in the draft accounting order in its Application (see Ex. H1-1-1, Section 6; Ex.L-9.8-Staff-218); however, if the OEB would be assisted by draft accounting orders as part of the Payment Amount Order process, then OPG will provide them.

10.8.3 Nuclear ROE Variance Account

OPG proposes to establish the Nuclear ROE Variance Account to record the nuclear revenue requirement impact of the difference between (i) the approved ROE for the nuclear business in 2018-2021 in this proceeding and (ii) the actual ROE that the OEB will specify for each year in its future prescribed ROE determinations. This account is proposed to take effect on January 1, 2018. OEB staff does not object to the account.

CCC, LPMA, and SEC, on the other hand do (CCC argument, p. 27; LPMA argument, p. 25; SEC argument, para. 1.3.21). They argue that it is inconsistent with the Rate Handbook and contrary to O. Reg. 53/05.

Whether or not the Nuclear ROE Variance Account is inconsistent with the recently issued rate handbook, it is consistent with the handbook that was in place at the time OPG submitted its Application. More importantly, comparable treatment to updating the ROE annually has been granted by the OEB in other Custom IR applications.[136]

Further, the suggestion that the account is contrary to the regulation is without merit. The requirement in section 12(v)(i) of O. Reg. 53/05 that the OEB set revenue requirement on a five-year basis for OPG's nuclear facilities must be interpreted in the context of the regulation as a whole. Elsewhere, of course, the regulation mandates certain other D&V accounts. There can be no serious argument that this is contrary to section 12(v)(i), just as there cannot be for the Nuclear ROE Variance Account.

10.8.4 Hydroelectric Capital Structure Variance Account

Hydroelectric Capital Structure

OPG proposes to establish the 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 by the OEB in EB-2013-0321 that underpins the hydroelectric payment amounts in this proceeding for 2017-2021. This account is proposed to take effect on January 1, 2017. OEB staff do not take issue with the

[136] EB-2014-0002, Horizon Utilities Settlement Proposal, p. 15.

nature of this account, nor express any concerns with respect to the causation, prudence, and materiality of the proposed account (OEB staff argument, p. 138).

CCC, LPMA, and SEC oppose the account (CCC argument, p. 39; LPMA argument, p. 26.; SEC argument, para. 1.3.20). They argue that adjusting the equity ratio for the hydroelectric payment amount is inconsistent with IRM. OPG disagrees. This is not a situation of attempting to adjust the ROE (which OPG has not proposed to do, see below). Rather, the account is intended to capture OPG's unique circumstances and the fact that only the hydroelectric portion of its regulated facilities are subject to formulaic IRM adjustments. In this regard, the account is necessary to maintain the single capital structure which applies to OPG's entire regulated business.

Concentric and Brattle testified to the appropriate equity ratio. The issue is discussed in greater detail in Issue 3.1 (Section 4.1). Relevant here is that both experts agreed that their recommended equity ratio should apply to both the Hydroelectric and Nuclear businesses. They further testified that if the ratio applied to the Nuclear business only, their recommended capital structure would have been much higher. OPG's capital structure has always been set on an OPG-wide basis and the account is necessary to maintain that structure.

Hydroelectric ROE

OPG has not proposed to make any adjustments to the hydroelectric ROE embedded within base rates. Maintaining a constant ROE through the IR term is consistent with OEB practices. SEC supports this concept stating that they "agree that the ROE in the rebasing year for hydroelectric should be fixed at 9.33%, the rate embedded in base rates, and kept constant throughout the IRM term" (SEC argument, para. 10.6.2).

Elsewhere SEC reverses course arguing that if the OEB determines that the hydroelectric capital structure variance account is approved, the ROE embedded in OPG's hydroelectric rate should be reduced (SEC argument, para. 10.5.8). In making its argument, SEC layers on the invective, calling OPG's proposal "just another straw man" (SEC argument, para. 10.5.9), deliberately inserted by OPG to be denied by the OEB. OPG forcefully rejects these criticisms.

The simple fact is that updating the ROE embedded in the hydroelectric base rate is inconsistent with IRM methodology and contrary to the settlement agreement reached by the parties (including SEC) under which the adjustments OPG has made to the regulated hydroelectric payment amounts arising from EB-2013-0321 for establishing base rates for applying the hydroelectric IRM is a settled issue (Ex. O-1-1, p.15-16; Tr. Vol. 9, p. 1).

11.0 REPORTING AND RECORD KEEPING REQUIREMENTS

11.1 Issue 10.1

Secondary: Are the proposed reporting and record keeping requirements appropriate?

OPG proposes to continue to report as previously directed by the OEB (EB-2010-0008, Decisions with Reasons, March 10, 2011, p. 151). OEB staff have no concerns with OPG's proposed reporting and record keeping requirements (OEB staff argument, pp. 139-140), and are the only party to make submissions on this issue. OPG submits that the OEB should find OPG's proposed reporting and record keeping requirements are appropriate as outlined in section 11.1 of the AIC.

As an administrative matter, OPG requests that the OEB extend the deadline by which OPG must provide "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" (EB-2010-0008, Decision and Order, p. 151). Under the existing requirements OPG must provide this analysis by June 30th of each year. OPG requests that the date be extended to July 15th of each year beginning in 2018.

OPG has requested this extension due to the challenges it has faced in meeting this deadline as a result of its corporate tax returns also being due on June 30th of each year. This reporting requirement relies heavily on OPG's final tax calculations, which has created a delay in the filing (or a correction filed after the fact) in nearly every year the reporting requirements have been in place. OPG submits that it would be better prepared to provide the OEB with accurate figures in its annual submissions should the deadline be extended by two weeks. OPG recognizes that as a result of the timing of this request, should the OEB decide to grant the extension, it would apply for the period 2018-2021.

11.2 Issue 10.2

Primary: Is the monitoring and reporting of performance proposed by OPG for the regulated hydroelectric facilities appropriate?

OPG proposes to continue reporting on the performance measures proposed in the previous payment amounts application, as shown in Chart 11.1, below (EB-2013-0321, Ex. F1-1-1, pp. 26-27). Beginning in 2017, OPG proposes to file an updated set of performance measures with the OEB annually. The updated measures would include the prior year's actual performance as well as targets for the then current year for each measure (Ex. A1-3-2, p. 43).

Chart 11.1

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 were the only party to make submission under this issue. While OEB staff submit that the safety and reliability performance measures proposed by OPG are appropriate, they propose that OPG should file the measures for each year and the company's targets for the same year (OEB staff argument, p. 141). OPG had proposed to file its targets for the following year (i.e., in 2018, OPG would file the actual performance for 2017 and the targets for 2018 for each measure). OPG does not object to OEB staff's proposal to synchronize the actual and target information (i.e., in 2018, OPG would file the targets and actual performance for each measure in 2017). Ultimately, the same information would be provided to the OEB under either approach.

OEB staff propose that OPG file its performance on the proposed performance measures over a five-year historical period. OPG does not object to this proposal.

OEB staff propose that OPG file a new performance measure: Total Generating Cost per MWh ("TGC/MWh") for the regulated hydroelectric business (OEB staff argument, p. 142). OEB staff incorrectly state that this measure would be consistent with OPG's internal reporting. As OEB staff's submissions note two paragraphs earlier, however, OPG does not calculate the TGC/MWh of the regulated hydroelectric business separately from the unregulated hydroelectric business (OEB staff argument, p. 142). Consequently, OPG does not have targets for the TGC/MWh of the regulated hydroelectric facilities that it could report.

OPG submits that it would not be appropriate to divide the TGC/MWh target between the regulated and unregulated facilities. As OPG's witnesses explained during the hearing, the company considers the efficiency of operations as a business and within regions, which include both regulated and unregulated plants (Tr. Vol. 9, pp. 89-90). TGC/MWh is valuable because it is a comprehensive business planning tool. Dividing it between regulated and unregulated facilities would be inconsistent with how OPG operates its hydroelectric business and it could result in less efficient operations and trade-offs between regulated and unregulated facilities. Such an outcome would not be in the best interest of ratepayers.

11.3 Issue 10.3

Primary: Is the monitoring and reporting of performance proposed by OPG for the nuclear facilities appropriate?

OPG proposes to report the key performance measures that are used in its annual nuclear benchmarking report (AIC, p. 155). The proposed nuclear performance measures are listed in Ex. A1-3-2, page 42, and in Chart 11.2.

OPG proposes to report on these metrics in the same manner and level of detail provided in Ex. F2-1-1, Attachment 1, page 6, Table 2, which summarizes OPG's nuclear performance compared to benchmark results, including best quartile and median information.

Chart 11.2

Nuclear Performance Measures (Separate measures will be filed for Darlington and Pickering Stations)	
Category	**Measure**
Safety	All Injury Rate (per 200k hours)
	Collective Radiation Exposure (person rem/unit)
	Airborne Tritium Emissions (curies)
	Industrial Safety Accident Rate (#/200k hours)
	Fuel Reliability Index (microcuries /gram)
	2-year Reactor Trip Rate (#/7000 hours)
	3-year Auxiliary Feedwater System Unavailability (#)
	3-year Emergency AC Power Unavailability (#)
	3-year High Pressure Safety Injection Unavailability
Reliability	Forced Loss Rate (%)
	Unit Capability Factor (%)
	Nuclear Performance Index (%)
	On-line Deficient Maintenance Backlog (work orders / unit)
	On-line Corrective Maintenance Backlog (work orders / unit)
	Chemistry Performance Indicator Annual YTD (#)
Cost Effectiveness	Total Generating Cost per Net MWh ($/MWh)
	Non-Fuel Operating Cost per Net MWh ($/MWh)
	Fuel Cost per Net MWh ($/MWh)
	Capital Cost per MW Design Electrical Rating ($k/MW)
Human Resources	18-month Human Performance Error Rate (#/10k ISAR hours)

OEB staff were the only party to make submission under this issue. OEB staff propose that OPG provide four categories of performance reporting in addition to the 20 performance measures proposed by OPG for the nuclear facilities. Specifically, OEB staff propose that OPG file the following further information:

1. Quartile benchmarking;
2. OPG nuclear performance on TGC, NPI and UCF;

3. Normalized performance; and
4. Non-normalized performance.

OPG does not object to the additional performance reporting measures proposed by OEB staff. In fact, it already proposed to file them in its AIC:

Quartile Benchmarking

OPG has proposed to report in the manner that OEB staff request. In its AIC, OPG stated that it proposed to report on the nuclear performance in the same manner and level of detail provided in Ex. F2-1-1, Attachment 1, page 6, Table 2 (AIC, p. 155, lines 15-19). This is the same table that OEB staff reference in footnote 431 of their argument.

TGC, NPI and UCF

Each of these measures is included at the station level in the table that OPG has proposed to file (AIC, p. 155, lines 15-19).

Normalized and Non-Normalized Performance

OPG has proposed to file Total Generating Cost per MWh on a normalized and non-normalized basis (AIC, p. 155, lines 27-28).

OEB staff propose that OPG file the full annual Nuclear Benchmarking Report on the preceding year's performance (OEB staff argument, p. 144). OPG does not object to this proposal. As OEB staff note, the "raw data" for the identified measures will be available earlier than the complete Nuclear Benchmarking Report. OPG agrees to file the performance results once available, to be followed by the full Nuclear Benchmarking Report, which OPG would file once it is finalized.

OEB staff also propose that OPG file performance metrics for each year and targets for that year (rather than OPG's proposal to file targets for the following year). OPG does not object to this change.

OEB staff propose that OPG provide performance for the five-year historical period on each of the approved performance measures. OPG does not object to this proposal.

11.4 Issue 10.4

Oral Hearing: Is the proposed reporting for the Darlington Refurbishment Program appropriate?

Substance of Reporting to the OEB

OEB staff, CCC, CME, SEC, EP and LPMA submit that OPG's reporting on DRP should generally be in accordance with the progress report template filed by Schiff Hardin in Undertaking J7.1 (OEB staff argument, p. 68; CCC argument, p. 35; CME argument, para. 165; SEC argument, para. 4.12.6; EP argument, para. 3.30; LPMA argument, p. 28). GEC submits that OPG should report on raw figures on cost and schedule performance as well as on CPI and SPI (GEC argument, p. 27). ED submits that OPG should report on actual versus forecast cumulative capital costs for the DRP, as well as CPI and SPI (ED argument, para. 91). PWU adopts OPG's proposal for reporting (PWU argument, para. 2).

According to OEB staff, the format of the report proposed by Schiff Hardin in Undertaking J7.1 sets out the level of detail that should be included in the annual report, which includes reporting on 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." OEB staff submit that this information will be useful to the OEB at the time any balance in the CRVA is brought forward for disposition and would be of assistance to the OEB in conducting a prudence review (OEB staff argument, p. 68). CME adopts this proposed use of the DRP reporting (CME argument, para. 163). Similarly, CCC submits that OPG should include as part of its reporting OPG's risk register and its corrective action program. CCC argues that such documents should be provided so that the OEB can review the manifestation and handling of risks as they happen rather than in summary after the fact (CCC argument, pp. 14-15).

OPG does not agree that this is an appropriate use of the annual reporting. In OPG's submission, reporting is intended to provide the OEB with an understanding of the DRP's progress rather than to supply an evidentiary basis for a future CRVA proceeding. This is especially true considering OEB staff's proposal to use the CRVA proceedings as a component-by-component prudence review as discussed above (see Issue 4.5, Section 5.5).

In OPG's submission, the central purpose of the annual reports is to provide the OEB with the most relevant, important, and helpful information so as to provide an understanding of the DRP's progress. These reports will necessarily represent a "snapshot" view at a single point in time of a program that is continuously developing. As such, they would not be an appropriate basis to determine whether OPG has acted prudently. To the extent that variances between approved and actual costs require a future CRVA proceeding or a prudence review, the onus will be on OPG to provide the necessary information.

Even Schiff Hardin, on which many intervenors rely, does not link the task of reporting to a future adjudicative review and does not require strict adherence to the outline set out in Undertaking J7.1. In fact, Schiff Hardin states in Undertaking J7.1 that:

> The exact structure and content of the report should be determined based on what is necessary for OPG to accurately and transparently report the status of the DRP including any actual or threatened risks to budget and schedule. The structure of the report can vary from the order listed below as long as all of the categories of information are adequately and transparently addressed.

OPG submits that, at the core of many of the intervenors' justifications for why detailed information is required is a desire to manage the Program or control its future progress. This is evidenced by submissions such as ED's, which notes that the reports are required to identify cost overruns or delays as early as possible so that planning can begin immediately regarding remedial steps, including off-ramps (ED argument, para. 92). EP similarly notes that reporting should be used as an early metric for whether OPG should continue planning for future units (EP argument, para. 3.30).

OPG submits that its annual reporting to the OEB is not for purposes of project management or to determine the DRP's future. It is OPG's role to manage and plan the Program. OPG's internal reports will contain very detailed metrics and identify issues and plans for remedial steps, consistent with OPG's responsibility to undertake the necessary actions to safely deliver the DRP on or under budget and schedule and with the requisite level of quality. The level of information required to manage the project is orders of magnitude beyond that which is required to keep the OEB informed of its progress. OEB staff acknowledge in their argument that reporting will not be used to assess whether the Program should continue on a go forward basis (OEB staff argument, p. 67). That is the role of OPG's shareholder and OPG, and different reporting necessarily exists within the Program and to the shareholder for that purpose.

OPG submits that the information OPG committed to reporting on in Chart 5.4 of the AIC provides the most relevant, important and helpful information to provide the OEB with an understanding of the DRP's progress. Unlike the detailed information and narratives proposed by Schiff Hardin and adopted by intervenors in this proceeding, the information proposed by OPG will provide the OEB with the most important metrics for determining the status of the DRP in terms of progress, safety, quality, cost and schedule. OPG submits that the simple but powerful metrics OPG proposes (such as cost performance and schedule performance indices) are superior to the information proposed by intervenors, and that these metrics will allow the OEB to compare and track trends throughout the life of the DRP.

Specifically, OPG submits that the level of detail proposed by Schiff Hardin in Undertaking J7.1 will be excessive and unhelpful to the OEB for the purposes of tracking the progress of the DRP for the following reasons:

1. Some of the listed information is not pertinent for the current status of the Program, which has advanced into the Execution Phase. During this phase, the most important information is that which demonstrates how the Program is performing relative to its planned schedule and cost, and if issues arise, how OPG is addressing them. The level of granularity suggested by Schiff Hardin, including details on procurement and engineering status, most of which were completed in the Definition Phase (see Ex. D2-2-4, pp. 5-6 regarding engineering, and Ex. L-4.3-2 AMPCO-63 with respect to procurement of tooling), are not applicable for the current status of the DRP.

2. As OPG has explained throughout the proceeding, the DRP is a megaprogram comprised of approximately 560 projects to be completed over the lifetime of the Program (Ex. D2-2-5, p. 5). To report at the project level would create an inordinate amount of information for the OEB to assess, and is also inconsistent with the review of the DRP as a megaprogram. In addition, this would create a burden to the Program given the large volume of information that it will have to gather and summarize for reporting to the OEB on a regular basis.

3. Some of the information required from a strict adherence to Undertaking J7.1 would prohibit the report from being a public report because this information is highly commercially sensitive. For example, disclosure of specific contractor performances on each component, invoicing status for major contractors and significant contractor claims, disputed change orders or commercial issues cannot be made public as it would result in commercial harm to the contractors, prejudice OPG's ability to pursue claims, and ultimately, will increase the cost of the DRP for ratepayers. This type of information has consistently been treated as confidential information in both this proceeding and in prior OPG proceedings (see, for

example, in this proceeding, Decisions and Orders on Confidentiality dated January 31, 2017 and May 4, 2017). Also, OPG has treated contingency draws and the consequent contingency remaining at the project, bundle, and program levels as commercially sensitive information throughout the proceeding, and the approach has been accepted by the OEB (see, for example, in this proceeding, the Decision and Order on Confidentiality dated January 31, 2017, and the decision issued during the hearing with respect to documents containing the above information at Tr. Vol. 16, p. 156).

4. The proposed attachments set out in Undertaking J7.1 include all audit reports and third party oversight reports that are generated, including those for OPG's Board of Directors. Public reporting is not the mandate of OPG's auditors and third party oversight (Ex. L-10.4-20 VECC-44). In the current proceeding, OPG has produced similar information and reports (with redactions), which amounted to thousands of pages of information. The level of information in these reports is not appropriate for public reporting and is not required to inform the OEB about the current status of the DRP. To the extent this information is relevant for any future prudence review or review of the CRVA, OPG will file this information at that point.

5. OPG observes that intervenors and the OEB may need to spend a great deal of money on outside consultants to examine large amounts of Program data if the approved reporting frequency is on a quarterly or semi-annual basis as proposed by a large number of intervenors. OPG submits that quarterly or semi-annual filing of large volumes of information is not necessary to effectively monitor the status of the DRP.

OPG has nevertheless reviewed Undertaking J7.1 and considered the information provided there. While OPG believes the metrics it has proposed would have captured or aggregated most of what would be provided using Undertaking J7.1, OPG would support the addition of the following reporting metrics and categories if the OEB would find them helpful:

- **Introduction and Table of Contents**
- **Executive Summary**
- **Overall DRP Status**
- **Cost**: Actual versus forecast cumulative capital costs for the DRP (ED argument, para. 91).
- **Schedule**: Raw figures on schedule performance (GEC argument, p. 27).
- **Engineering**: Summary of engineering status and key issues.
- **Procurement**: Summary of procurement status and key issues.
- **Construction**: Summary of (1) construction progress and analysis of any material variances from plan, (2) any material labour issues, and (3) any material environmental issues.

- **Testing, Start-up and Commissioning**: Summary of systems tested, commissioned, restarted, and any key test results and issues at the bundle level.
- **Program Risks and Risk Management**: Key risks and mitigations, as well as key issues and corrective actions.
- **Staffing**: Actual staffing level against plan, changes to plan and efforts to fill open positions.

Beyond these categories, OPG submits that all other metrics proposed in Undertaking J7.1 are inappropriate either for this phase of the Program (which is expressly contemplated by Schiff Hardin in Undertaking J7.1), or for the scope of an annual report to the OEB. For ease of reference, below is an updated set of metrics that OPG would support reporting to the OEB on an annual basis. As addressed below, OPG emphasizes that reporting any more frequently than on an annual basis would be both unnecessary and burdensome to the Program, especially in light of the additional information OPG proposes to provide. Reporting on the below metrics represents a significant amount of work, and any frequency greater than annual may require dedicated staff to meet reporting demands.

Chart 11.3
Revised Proposed Content/Metrics for Reporting to the OEB
(italicized metrics are in addition to OPG's previous proposal)

Category	Measure
Introduction and Table of Contents	*N/A*
Executive Summary	*N/A*
Overall DRP Status	• *High level overview of the DRP itself*
Progress	• Key Achievements • % Complete
Safety	• All Injury Rate • *Lost hours due to injuries* • *Explanation of any safety programs/initiatives launched by OPG/contractor*
Quality	• # of Significant Field Rework Events
Cost	• Cost Performance Index • Life-to-date cost • *Actual versus forecast cumulative capital costs* • Forecast to Complete • Estimate at Complete
Schedule	• *Current schedule performance* • Schedule Performance Index

	• Status of Key Milestones • Critical Path Progress • Forecasted Completion Dates
Engineering	• *Summary of engineering status and key issues*
Procurement	• *Summary of procurement status and key issues*
Construction	• *Summary of construction progress and analysis of any material variances from plan* • *Summary of any material labour issues* • *Summary of any material environmental issues*
Testing, Start-up and Commissioning	• *Summary of systems tested, commissioned, restarted, and any material key results and issues*
Program Risks and Risk Management	• *Key risks and mitigation* • *Key issues and corrective actions*
Staffing	• *Actual staffing levels against plan* • *Changes to staffing plan* • *Efforts to fill open positions*

Frequency of Reporting to the OEB

SEC, EP, GEC and ED submit that OPG should provide the written report to the OEB on a quarterly basis (SEC argument, para. 4.12.6; EP argument, para. 3.30; GEC argument, p. 27; ED argument, p. 28). LPMA, acknowledging that quarterly reporting would not necessarily be required and would be an administrative burden to the Program, indicates that DRP reporting should be on a semi-annual basis (LPMA argument, p. 29). OEB staff and PWU agree with OPG that annual DRP reporting to the OEB is sufficient in terms of frequency (OEB staff argument, p. 67; PWU argument, para. 2).

OPG submits that annual reporting is the most appropriate frequency. As discussed above, the reporting proposed by intervenors contains significant detail and is quite granular, including information and attachments that would require OPG to conduct legal reviews for confidentiality. To provide this level of reporting more frequently than on an annual basis would be a significant burden to the Program, the company and likely for the OEB.

OPG submits that annual reporting is the most appropriate frequency whether the OEB accepts OPG's original proposal for reporting metrics or the revised proposal above in Chart 11.3. As

OPG indicated, the central purpose of the reports is to provide a clear and detailed understanding of the DRP's progress. The DRP is a complex and large program that will operate over an extended duration. A progress report generated annually containing key metrics will provide the OEB with a good summary of progress milestones and issues over a time period long enough for an issue to arise, be identified, addressed, and properly reported on.

Reporting more frequently would not provide any incremental value to the OEB. The reports will issue too frequently to show significant progress from report to report. Trends, for example, will be less meaningful given that there will be minimal change over the reporting period. As OPG has committed to providing simpler reporting to the public through its website on a more frequent basis, OEB reporting more often than annually is not required (Ex. L-4.3-1 Staff-223; Ex. JT1.18). OPG submits that detailed reporting on a more frequent basis than annually will be costly to OPG, and cause the OEB and the parties in this proceeding to require outside expertise to interpret the detailed project information provided.

Independent Monitor

EP is the only party to submit that the OEB should consider retaining an independent auditor that reports to the OEB on an annual basis (EP argument, p. 18). EP argues that this information would provide the OEB with a more independent assessment of the performance of the Unit 2 refurbishment than an auditor embedded within the company.

OPG submits that this proposal is unnecessary. As OPG indicated throughout this proceeding, OPG has an extensive, layered assurance plan in place for monitoring and overseeing the DRP (AIC, pp. 62-64). The oversight in place includes both internal (Internal Audit and Nuclear Oversight groups) and external independent parties such as BMcD/Modus, the Refurbishment Construction Review Board ("RCRB"), as well as an independent advisor that provides oversight of the DRP to the Ministry of Energy. The RCRB, in particular, was specifically put together to support program-level oversight through a panel of approximately six external members with expertise in nuclear plant operations, mega-projects and relevant regulatory requirements, with support from one internal OPG member.

In fact, the RCRB has opined already that it is clear that there is a significant amount of oversight activities for the DRP ongoing, and that there were nearly 60 different audit/oversight activities in 2016 conducted by both internal and external groups. The RCRB strongly recommended that “these activities are consolidated as much as possible and resource balanced. [...] As the organization enters the execution phase, OPG will clearly need to be mindful of this burden, but still provide the right level of oversight for this project” (Ex. L-4.3-15 SEC-37, Attachment 1, p. 6).

No parties have argued that the oversight in place for the DRP is insufficient. Furthermore, both Pegasus-Global and Schiff Hardin have opined that OPG has appropriate oversight in place for the DRP (AIC, p. 64). OPG submits that any additional oversight bodies would not only be unnecessary, but would be counterproductive. They would add a significant burden to the Program, one which the RCRB has already indicated is undesirable.

12.0 METHODOLOGIES FOR SETTING PAYMENT AMOUNTS

12.1 Hydroelectric

12.2 Issue 11.1

Oral Hearing: Is OPG’s approach to incentive rate-setting for establishing the regulated hydroelectric payment amounts appropriate?

As described in Ex. A1-3-2 and the AIC, this Application marks the first time an IR framework has been proposed for OPG’s prescribed hydroelectric assets. Given the novelty of the hydroelectric IR framework, OPG was pleased to note that the parties generally support significant elements of its proposal. The parties either support (or do not oppose) the overall price-cap index approach that OPG has proposed. They also support (or do not oppose) major elements of the IRM framework, including the fixed 0.3% stretch factor for the five-year IR term, the availability of an ICM, and the availability of Z-factor treatment for material unforeseen events.

The areas of dispute generally fall into four main categories:

1. **GRC:** The treatment of the Gross Revenue Charge ("GRC"), payable to the Province,[137] in the proposed price-cap index, which is discussed below in Section 12.2.1.

2. **2017 I-Factor:** The calculation of the inflationary adjustment for 2017, which is discussed in Section 12.2.2.

3. **Productivity Factor:** The appropriate productivity factor for the price-cap index. Given the complexity of this issue, OPG's reply is divided into multiple sub-topics in Sections 12.2.3-12.2.6.

4. **Materiality Threshold:** Whether to increase the $10M regulatory materiality threshold, which is discussed in Section 12.2.7.

The parties' submissions mainly relate to the proposed productivity factor. The two experts differ on whether the productivity trend is slightly negative or slightly positive: London Economics International LLC ("LEI") found that the trend was -1%, and Pacific Economics Group ("PEG") found that the trend was 0.29%. However, as shown below there is good reason to doubt whether PEG's study uses an appropriate <u>output measure</u> or an appropriate <u>depreciation assumption</u> for hydroelectric facilities. As discussed in Section 12.2.3, if the OEB accepts OPG's submissions on either of these issues, the result of PEG's study would become negative. Based on these facts alone, OPG's proposed 0% productivity factor, advanced pursuant to the OEB's policy determination, is entirely reasonable.

Several parties also made submissions on the interaction of the CRVA and OPG's proposal to ensure that the CRVA does not result in "double recovery" of funding for capital projects. OPG's responses to these submissions are in Issue 9.2 (Section 10.2). Subject to a small adjustment, OEB staff support OPG's proposal as set out in Ex. H1-1-2.

12.2.1 The Proposed Inflation Factor Accurately Reflects the Inflationary Pressures on OPG

OPG proposes an annual inflation adjustment (or "I-factor") that is methodologically and substantively consistent with the I-factor used by the OEB to adjust electricity distributor's rates under 4GIRM. The proposed I-factor escalates all non-labour costs[138] by the Canadian Gross Domestic Product Implicit Price Index – Final Domestic Demand ("GDP-IPI (FDD)"), and labour

[137] References to Gross Revenue Charges in this submission also include water rental charges and other water agreement costs payable to other governments, agencies, or entities (e.g., Parks Canada, Government of Quebec, St. Lawrence Seaway Management Corporation, Hydro Quebec) and funding contributions to the Lake of the Woods Control Board and the Ottawa River Regulation Planning Board (Government of Canada).
[138] Including cost items like depreciation expense, ROE, materials and services, GRC and other taxes.

costs by the Average Weekly Earnings for Ontario – Industrial Aggregate ("Ontario AWE"). OPG relied on expert advice from LEI to determine the appropriate weighting of the two sub-indices to reflect the cost share for labour costs versus all other costs (i.e., capital and all other non-labour related costs) for the hydroelectric generation industry (Ex. A1-3-2, pp. 13-14). These are the same indices that the OEB uses to estimate inflation in the electricity distribution industry, and the weighting approach is also consistent with the OEB's methodology of relying on weights developed by looking at the implied labor and non-labor cost shares for medium and large electricity distributors.[139]

OEB staff and LPMA support the I-factor methodology that OPG has employed (OEB staff argument, p. 146; LPMA argument, p. 29). OEB staff state that OPG's approach "eases transparency, understanding, and ease of calculation of the measure" by using the same Statistics Canada data as the OEB (*Id.*). OEB staff and LPMA also support the weighting proposed by LEI (*Id*.). No parties oppose the overall I-factor methodology that OPG has proposed.

The only area where any party proposes a change to the I-factor is in relation to the GRC component of the company's hydroelectric revenue requirement. SEC argues that the I-factor should give a 0% weighting to the proportion of GRC in revenue requirement (SEC argument, para. 10.2.33), essentially carving-out this one cost category from escalation under the price-cap index. CME's submissions are substantively identical to SEC's proposal (CME argument, pp. 71-73).

OEB staff do not share SEC's assessment of the GRC. In their view, "inflation-less" costs like the GRC are reflected in the GDP-IPI (FDD) (OEB staff argument, p. 148). Despite this acknowledgement, OEB staff propose a compromise. They suggest the OEB treat the GRC like a Z-factor for a mid-term change in tax rates. Under OEB staff's proposal, the OEB would include the GRC in base payment amounts as if it resulted from a mid-term tax rate change, allowing inflation on only 50% of the GRC (OEB staff argument, p. 149).

[139] EB-2010-0379, Report of the Board: Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors, issued November 21, 2013 and as corrected on December 4, 2013, p. 9.

As set out in detail below, OPG submits that SEC's proposal is inconsistent with the treatment of other taxes under 4GIRM, and is based on a fundamental misinterpretation of what the GDP-IPI (FDD) represents. OEB staff's proposed compromise, while in the right direction, lacks a policy basis and is inconsistent with OEB staff's assessment that the GDP-IPI (FDD) already reflects "inflation-less" costs in the Canadian economy.

Finally, CCC and LPMA propose that GRC be treated as a Y-factor: removed entirely from the price-cap index and passed through at cost (CCC argument, p. 38; LPMA argument, p. 31).[140] But GRC is not a pass-through cost and should not be treated as a Y-factor. As described below, GRC is no different from other taxes that are included in base payment amounts on a forecast basis and adjusted by the annual adjustment mechanism. And, as a practical matter, OPG notes that implementing Y-factor treatment for GRC at this time would be contrary to the logic of the methodologies underlying the Water Conditions Variance Account, the Hydroelectric Surplus Baseload Generation Variance Account and the Gross Revenue Charge Variance Account that were settled in this proceeding.[141]

The GRC is not Meaningfully Different from Other Taxes in Revenue Requirement

There is no meaningful difference between the GRC and other taxes funded through OPG's hydroelectric payment amounts. The GRC is primarily a bundle of three provincial taxes that are included in hydroelectric revenue requirement on a forecast basis, like the other taxes payable by OPG. GRC consists of:

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[140] At p. 38 of their submissions, CCC asks OPG to clarify the status of the GRC reduction under *Ontario Regulation 124/02* pertaining to production increases at the Sir Adam Beck plants due to the operation of the new Niagara Tunnel, and how such a reduction would impact the payment amounts during the IR term. OPG confirms that no decision on this GRC reduction has been issued by the Ministry of Natural Resources and Forestry at this time. As noted in Ex. H1-1-1, p. 17, if and when such a reduction is approved by the Ministry, OPG will record a credit in the Gross Revenue Charge Variance Account "by applying the approved reduction to the 2014-2015 forecast gross revenue charge costs included in the revenue requirement that were approved by the OEB in EB-2013-0321, averaged as applicable, and holding all over variables constant."

[141] Specifically, in the approved Settlement Agreement, parties agreed that "…the proposed continuation of deferral and variance accounts is appropriate on the basis of OPG's evidence. Provided that, for greater certainty, agreement to continue the accounts is not intended to imply agreement with the existing or proposed methodology, entries, or other terms relating to those accounts that are excluded from the settlement of issues 9.1, 9.2, and 9.3." (Ex. O-1-1, pp. 14-15; Tr. Vol. 9, p. 1; see Issue 9.2, Section 10.2). None of the three accounts identified above were excluded from the settlement. The methodologies for these accounts compute variances in GRC costs associated with certain specific events – changes in production as a result of changes in water conditions, occurrence of surplus baseload generation conditions or an approved GRC reduction pertaining to production increases due to the operation of the new Niagara tunnel (Ex. H1-1-1, pp. 16-17). This approach would not be applicable if GRC costs were treated as a pass-through (and therefore automatically true-up for these and any other source of variances from forecast). Thus, implementing Y-factor treatment for these costs could result in double counting.

- two property taxes that range from 2.5% and 26.5% depending on the actual production at each station, and
- a water rental tax that is currently set at 9.5% on each hydroelectric station's deemed actual gross revenue from generation.

GRC is not a fixed charge, as SEC suggests (SEC argument, p. 115). As OPG's witnesses noted on multiple occasions during the hearing, the amount of GRC included in base hydroelectric payment amounts will be different from the amount that OPG will actually pay (Tr. Vol. 9, p. 90, lines 17-22; Tr. Vol. 10, p. 80, lines 4-16). The property taxes in the GRC have multiple thresholds that vary depending on actual production, ranging from 2.5% to 26.5%. Further, the amount of GRC payable must be forecast based on production and deemed gross revenue at each individual hydroelectric station. In effect, GRC is a forecast amount for a bundle of taxes, set on a variable rate and dependent on the actual level of production at each station.[142]

SEC's argument rests on the premise that the GRC is inherently different from the other taxes that are included in OPG's revenue requirement. OPG disagrees. As detailed in Ex. F4-2-1, OPG is subject to a variety of taxes, including other property taxes and commodity taxes. There is no meaningful difference between the property taxes in the GRC and the property taxes described in Ex. F4-2-1. Nor is there any significant difference between the commodity tax (e.g., HST) that OPG pays on the goods and services it purchases to operate its business and the water rental tax that it pays for the use of water to power the turbines. These taxes do not scale directly with ROE, and yet it is indisputable that they are included in revenue requirement for LDCs on a forecast basis under 4GIRM.

SEC's Proposal is Inconsistent with 4GIRM

SEC proposes that the OEB carve-out a category of revenue requirement from the I-factor, while continuing to use a high-level macroeconomic index to determine the remainder. That kind of piecemeal approach is inconsistent with the OEB's approach to determining the I-factor under 4GIRM. OPG submits that it would be inappropriate to carve-out GRC, or any other

[142] The Ontario Ministry of Finance provides a more detailed breakdown of GRC at http://www.fin.gov.on.ca/en/tax/grc/.

single component of a company's costs, from an IRM framework without customizing the price-cap index to reflect the narrower basket of costs that remain.

SEC states that the OEB uses the GDP-IPI (FDD) to represent inflation on portions of a company's revenue requirement for which it has not been able to identify a more appropriate inflationary index (SEC argument, p. 116, para. 10.2.24). That is not true. The OEB does not use the GDP-IPI (FDD) as an "index of last resort" to represent inflation for cost categories where it cannot be more specific. To the contrary, in the Report of the Board on rate-setting under 4GIRM, the OEB stated that it selected GDP-IPI (FDD) to track non-labour inflation specifically *because* it is a broad measure of the overall inflation in the economy. The OEB states that it selected the GDP-IPI (FDD) precisely because its "broad coverage makes it stable and, for a macroeconomic measure, reasonably reflective of inflation in the prices of distributor inputs."[143] Nowhere in its Report does the OEB state that it uses GDP-IPI (FDD) because it cannot identify more granular sub-indices for the various components of a utility's revenue requirement. SEC cites no evidence in support of this assertion.

Under 4GIRM, the GDP-IPI (FDD) does not directly track the prices of each utility cost component. Rather, it is an "all-in" measure that reflects the change in prices of all domestically produced goods and services, across the entire Canadian economy. Under 4GIRM, the I-factor does not directly match the inflation of specific cost components of a company's revenue requirement. By design, GDP-IPI (FDD) captures all changes in the prices of goods and services, including those like GRC that do not necessarily increase on a year-over-year basis.

The I-factor established by the OEB under 4GIRM reflects the fact that not all prices increase or inflate on a year-over-year basis. As OEB staff observe, the GDP-IPI (FDD) accounts for "inflation-less" costs like the GRC (OEB staff argument, p. 148). OEB staff submit that there is "no reason to believe that 'inflation-less' costs are not appropriately reflected in a well-established Government-published statistic such as GDP-IPI" (OEB staff argument, p. 148). OPG agrees. As OEB staff note in their submissions, other businesses have costs that do not inflate – these costs would be captured by GDP-IPI (FDD) (OEB staff argument, p. 147). In

[143] EB-2010-0379, Report of the Board, issued November 21, 2013 and corrected December 4, 2013, p. 7.

fact, the prices of some goods and services have likely decreased with time, and others will have been static.

In summary, SEC's proposal is incompatible with a 4GIRM-based rate-setting framework because it would arbitrarily require the OEB to selectively carve out an element of OPG's revenue requirement from the I-factor. Selective carve-outs, as proposed by SEC, are inconsistent with the comprehensive nature of IRM rate-setting, and would be inconsistent with the OEB's treatment of other taxes in this Application and in others.[144]

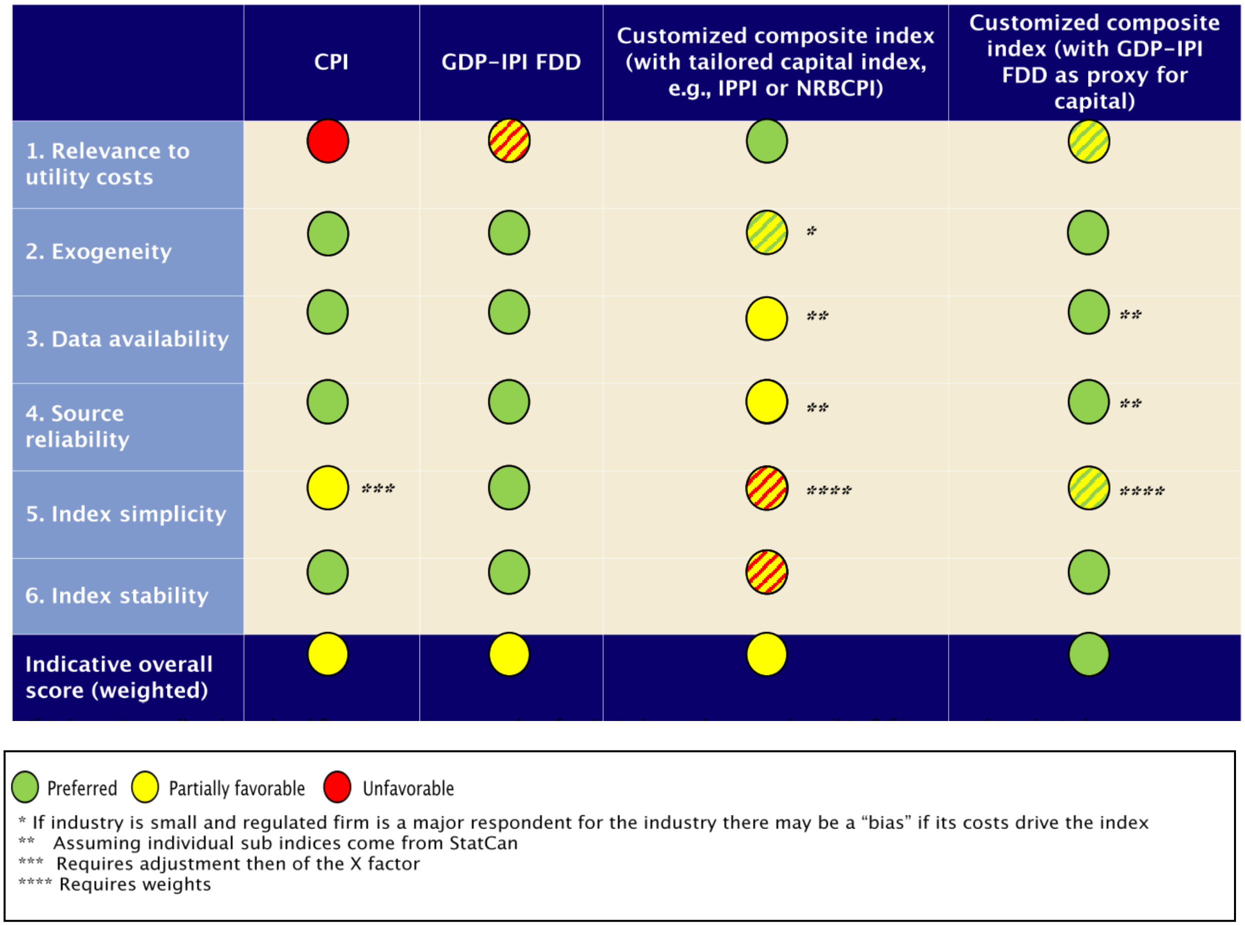
SEC Misinterprets the Evidence on the I-factor

During the hearing, SEC asked LEI whether the I-factor should include zero inflation for the portion of the revenue requirement related to GRC. LEI stated that it would not be appropriate to adopt SEC's proposal, since the GRC is essentially a tax. LEI confirmed that a macroeconomic index like GDP-IPI (FDD) applies to taxes like GRC (Tr. Vol. 10, p. 90, lines 11-28).

SEC misinterprets LEI's evidence on the proposed inflationary index. SEC's argument focuses exclusively on the first criterion listed in Chart 12.1: "Relevance to utility costs" (SEC argument, p. 113).

[144] SEC also challenges the 12% weighting that OPG has proposed for labour costs within its proposed I-factor, which SEC believes should be 14% (SEC argument, p. 114). SEC's 14% weighting is based on OPG's specific revenue requirement breakdown. SEC's approach is inconsistent with how the OEB calculates the weighting of the I-factor under 4GIRM. The OEB uses industry cost shares to calculate the appropriate weighting of the I-factor sub-indices, as LEI did when recommending the 12% weighting for labour costs proposed by OPG in this Application (Ex. A1-3-2, Attachment 3, p. 5).

Chart 12.1
(Ex. A1-3-2, Attachment 3, p. 7)



While it is important to select an inflation index that is relevant to the regulated company's costs, the other criteria are also important. LEI proposed a two-factor composite index as shown in the fourth column of Chart 12.1.

SEC's proposal offers no principled basis on which to carve out the GRC; it cherry-picks a particular cost category and excludes it from the price-cap index. If the OEB wishes to break out inflationary trends for individual cost categories, a principled method of doing so would be to use a more granular multi-factor composite index, as shown in the third column of Chart 12.1. As the Chart illustrates, such an approach may be aligned with the "relevance to utility costs" criterion, but it performs poorly on all other criteria (which may be why the OEB did not use this approach in 4GIRM). The bottom row, labeled "Indicative overall score", captures the overall conclusions of LEI's analysis. As is apparent from the Chart, a customized composite index approach raised the most problems and scored worst. Based on their analysis, LEI recommended a two-factor composite inflation index using GDP-IPI (FDD). OPG adopted LEI's recommendation because it matches the OEB's macroeconomic approach in 4GIRM.

OPG also notes that the methodology of OPG's proposed inflation factor has been known to intervenors since 2014. The structure of the proposed I-factor and LEI's supporting research were shared with SEC and other parties at the first stakeholder information session regarding this Application, held on December 17, 2014.[145] Despite this, SEC did not raise its concerns with LEI's approach until the hearing of this proceeding, nor did it raise the issue when cross-examining PEG.

OEB Staff's 50% GRC Weighting Proposal is Arbitrary and Inconsistent with 4GIRM

OEB staff analogize the GRC to a Z-factor for a change in tax rates during the IR term. They propose to "split the difference" between OPG's proposed I-factor and SEC's proposed exclusion of GRC (OEB staff Argument, p. 148). OPG submits that the issue before the OEB is not analogous to a mid-term change in tax rates, and the OEB staff's compromise, offered as a middle ground, is arbitrary and inconsistent with 4GIRM rate-setting.

OEB staff propose that the I-factor should be modified to assign 0% inflation to approximately 50% of the GRC-related revenue requirement (OEB staff argument, p. 148). In support of their proposal, they cite the OEB's 2008 decision regarding whether mid-term tax changes were captured by Union Gas' inflation factor, which was subsequently adopted as part of the Z-factor in the 3GIRM rate-setting framework.[146]

A change to tax rates during an IR term is not analogous to carving out a cost from the price-cap index. If the Province were to change the rates of the taxes that make up the GRC, then OEB staff's analogy would be accurate. In fact, it wouldn't even be an analogy – it would simply be an example of a change in tax rates. However, that is not the situation before the OEB in this proceeding.

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[145] The material from this session continue to be available at: http://www.opg.com/about/regulatory-affairs/stakeholder-information/Pages/payment-amounts.aspx.

[146] Decision EB-2007-0606/0615, July 31, 2008, pages 8-9; EB-2007-0673, *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*, September 17, 2008, page 35.

In its submissions, SEC responds to OEB staff's proposal for applying a 50% weighting to GRC in the I-factor. OPG cannot follow the logic of SEC's submissions, which imply that the OEB's 4GIRM I-factor somehow double-counts the growth in labour costs between the GDP-IPI (FDD) and Ontario AWE (SEC argument, p. 116). In any case, if SEC's criticism of OEB staff were correct – which OPG does not accept – it would seem to follow that the criticism would apply equally to the determination of electricity distributors' rates under 4GIRM. That conclusion would be a significant challenge to the OEB's standard rate-setting methodology; there is no evidence on the record to support SEC's conclusion, nor is this Application the appropriate forum in which to investigate any such change.

OPG submits that the inflation factor, and specifically the GDP-IPI (FDD) sub-index, appropriately applies to all non-labour components of the hydroelectric payment amounts including GRC and other taxes. It should be approved without adjustment.

12.2.2 OPG Accepts OEB Staff's Calculation of the 2017 I-Factor

OPG calculated the proposed I-factor in a manner that it understood to be consistent with the methodology used by the OEB to calculate the I-factor used in the 3GIRM and 4GIRM methodologies, based on materials published by the OEB. OPG adopted the proposed methodology because its intention is that the hydroelectric IR framework should deviate from 4GIRM only as is necessary to incorporate material differences between the distribution and hydroelectric generation industries (Ex. A1-3-2, p. 8).

OEB staff submit that OPG's methodology for calculating the 2017 I-factor is not consistent with the OEB's current practice. In their argument, OEB staff identified that the OEB adopted a natural log function for calculating the annual I-factor growth rate beginning with the 2014 Input Price Index. As OEB staff acknowledge, that change was not apparent from the documentation issued by the OEB at that time (OEB staff argument, pp. 150-151). Given the new information identified in their argument, OPG accepts OEB staff's proposed methodology for calculating the I-factor.

12.2.3 The 0% Productivity Factor Proposed in this Application is Appropriate

In this Application, OPG has proposed a price-cap index with a productivity factor of 0%. The issue before the OEB is not which Total Factor Productivity ("TFP") methodology to apply;

rather the issue is whether the 0% productivity factor proposed by OPG is appropriate for the IR term, based on the record of this proceeding.

OPG and OEB staff have both filed extensive expert evidence on the productivity growth trend of the North American hydroelectric generation industry, prepared by LEI and PEG, respectively. While the experts agree on many points, there are significant differences between their methodologies and the outcomes of their studies.

As set out in these submissions and in its AIC, OPG believes that LEI's methodology produces a superior measure of the industry's productivity, particularly as it relates to the output of the industry. However, the OEB is not required to choose between the two experts' methodologies in this proceeding – it must only determine whether OPG's proposed 0% productivity factor is appropriate for OPG's prescribed hydroelectric facilities in the 2017- 2021 period, based on the evidence.

And the record shows that a 0% productivity factor is reasonable, given two major areas of dispute between the two experts: the appropriate output measure and physical depreciation assumption for PEG's study.[147] If the OEB were to approve PEG's methodology but accept OPG's submissions on either the output measure or depreciation assumption, the result would be a negative productivity factor, as shown in Chart 12.2:

[147] As discussed below and in the AIC, no depreciation assumptions are required under LEI's approach, since all of the necessary data is available (AIC, p. 160).

Chart 12.2
Effect of Adjustments to PEG Study

Adjustment	Productivity Factor	Reference
None (as proposed by PEG)	**0.29%**	Ex. M2, p. 50
Production (MWh) as output measure	**-2.03%**	Ex. M2, p. 50
One-hoss-shay depreciation, Capacity (MW) as output measure	**-0.15%**	Ex. M2-11.1-OPG 2, Attachment A, p. 21
One-hoss-shay depreciation, Production (MWh) as output measure	**-2.26%**	Ex. M2-11.1-OPG 2, Attachment A, p. 19

12.2.4 OPG's Productivity Should be Measured Against the Output that Matters to Customers: Electricity (MWh)

LEI's Output Measure Accounts for Water Availability

OEB staff and SEC agree that LEI's study uses the ideal output measure for a TFP study: the actual electricity (MWh) generated by the stations being studied (OEB staff argument, p. 154; SEC argument, para. 10.3.13). As OPG summarized in its AIC, MWh is the superior output measure because:

1. It is how OPG is paid.
2. Most hydroelectric efficiency improvements are done to increase production (not capacity).
3. All 32 the studies reviewed by both LEI and PEG use MWh as the output measure.
4. OPG's key cost-effectiveness performance metrics are measured against MWh (AIC, pp. 161-163).

While OEB staff and SEC agree with OPG that MWh is the ideal output measure, they argue that there are practical shortcomings to the measure.

OEB staff submit that there is limited data on the price and availability of water used to produce electricity, meaning that an important data point is missing on the input side of the equation (OEB staff argument, pp. 154-155). OEB staff are correct that water flow data is not readily available. But they are incorrect to suggest that water should be treated as an input.

Specifically, OEB staff argue that water should be treated in a similar fashion to how fuel costs would be treated as an input in a TFP study of fossil fuel-fired generators. That is incorrect; hydroelectric generators do not pay a market price for water as would be paid for natural gas, coal or fuel oil. Water is not like a fuel expense.

Nevertheless, the OEB staff's arguments around water availability highlight an important consideration about the robustness of the TFP models produced by LEI and PEG.

The lack of consideration of water availability creates problems under PEG's approach, but not under LEI's. In PEG's study, the input measures are capital and O&M expenses, with capacity (MW) as the output measure. Water availability is not accounted for in any of PEG's measures. However, since LEI uses MWh as the output measure, its study indirectly reflects water availability through the output metric. MWh represents the flow of electricity services. Hypothetically, if water availability was not a constraint on a hydroelectric generator, the MWh of annual electricity production would be simply the number of hours in the year multiplied by the capacity of the plant, or MW. However, since water availability is constrained in reality, the actual MWh of annual electricity production will fall below this hypothetical figure. LEI used the actual MWh figure and thereby takes into account how water availability impacts annual production and TFP trends year over year.

OEB staff's comment raises another concern with PEG's methodology: since PEG's study ignores water availability, it creates an incentive for a generator to increase capacity regardless of whether water flow exists to utilize that capacity. Since PEG's study uses MW as the output measure, a generator could increase its notional productivity by "gold-plating" its facilities. Under PEG's approach, a generator that builds excess capacity (MW) would appear more productive, despite lacking the water to utilize that capacity. LEI's study does not encounter this problem, since its output measure (MWh) naturally and directly reflects the availability of water from year to year. Under LEI's approach, a generator's productivity would decrease if it were to build more capacity than is justified by water availability, since the input costs would increase without a corresponding increase in MWh output.

OEB staff acknowledge that capacity is not ideal, but nonetheless argue that capacity can be seen as an output, on the theory that generators build stations in response to water conditions (OEB staff argument, p. 155). Put another way, OEB staff argue a generator's outputs are represented by the stations it built. With respect, OEB staff's position is inconsistent not only with the reality of the hydroelectric business, but also with the OEB's focus on RRFE outcomes. OPG does not measure its output by the number of stations it builds. OPG's output – and the ultimate outcome that matters to its customers – is its ability to safely, reliably, and cost-effectively produce electricity (MWh) for the people of Ontario.

SEC Confuses the Two Studies' Treatment of the Niagara Tunnel

OPG must correct a glaring error in the preamble to SEC's submissions on the output measure. SEC describes the NTP as a "test" for whether LEI or PEG's output measure is right. SEC fundamentally misunderstood the evidence on how each expert's approach treats the NTP and other production-enhancing projects. SEC states:

> The LEI method does not consider the investment by OPG and its ratepayers in the Niagara Tunnel to increase productivity, since it did not increase capacity. The fact that more units of energy were produced from the turbines because of the increase in water flow is completely ignored. (SEC argument, p. 119, para. 10.3.11)

SEC has it backwards. Since the NTP increased production (MWh) but not capacity (MW), LEI's methodology would capture the increased MWh output from the project. Under LEI's method, production-enhancing projects like the NTP result in greater productivity, since they increase the output of the industry.

Actually, it is PEG's approach that does not consider the NTP and other production-enhancing projects, since they do not increase capacity. This is a critical flaw in PEG's study, since the majority of OPG's hydroelectric efficiency projects have been designed to increase production, not capacity (AIC, p. 162; Ex. A1-3-2, Attachment 6, p. 18; Tr. Vol. 9, p. 27, lines 11-14).[148]

SEC Misunderstands How Hydroelectric Generators Increase Efficiency

SEC's submissions reveal a basic unfamiliarity with how hydroelectric generators improve the efficiency of their operations: by increasing production. SEC states that capacity is a good

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[148] As explained in the AIC, LEI's approach does not reflect production-enhancing projects on the capital input measure, since LEI uses capacity to measure capital input quantities. LEI's approach is sensible because it is conservative. To the extent that projects like the NTP are not reflected in the capital input measure, LEI's results are too high (i.e., the productivity growth trend would be more negative if the costs of these projects were reflected in the capital input quantities) (AIC, p. 161, lines 9-16; Tr. Vol. 10, p. 42, lines. 5-6).

proxy for production since “circumstances in which energy production can be increased, without increases in capacity, and independent of hydrology or system demand, are uncommon” (SEC argument, p. 120, para. 10.3.14). SEC cites no evidence in support of its statement. In contrast, as described in the previous section, the majority of OPG’s hydroelectric efficiency projects have been designed to increase production, not capacity.

It makes sense that recent efficiency improvements in this mature, capital-intensive industry have mostly come from increasing the output of existing facilities. North American hydroelectric generators have not been focused on building new dams for decades. It is not credible to suggest, as SEC does, that OPG and other North American hydroelectric generators primarily increase their productivity by building new capacity, nor is it sensible to propose a productivity measurement that would encourage them to do so.

Put another way: LEI’s approach encourages OPG to get the most out of its existing facilities. PEG’s approach does not.

OPG’s counsel asked PEG’s witness, Dr. Lowry, about the fact that most upgrades to hydroelectric power plants are made to increase production (MWh). Dr. Lowry indicated that he did not consider the types of investments that hydroelectric generators actually make to improve the efficiency of their stations, and that he has no knowledge of whether they focus on increasing capacity or production.

> MR. SMITH: Would you agree with me that most investments to upgrade hydroelectric power plants are made to increase megawatt-hours?
>
> DR. LOWRY: I have no knowledge of whether they're more for… I don't know whether it's more for capacity or more for volume. Certainly the Niagara Tunnel project was an example of a volume-enhancing measure.
>
> MR. SMITH: Not a megawatt-enhancing measure.
>
> DR. LOWRY: And not a megawatt-enhancing. And another thing that upgrades could be for is just to be able to produce more in the system in the peak hours, in which the power is more valuable…
>
> MR. SMITH: Let me ask this question. Does OPG get paid on that basis that you've just described?

DR. LOWRY: I think that they have a little incentive mechanism for trying to bolster their peak period volume --

MR. SMITH: Which you've described as no incentive at all in your report.

DR. LOWRY: I don't wish to comment on that. … (Tr. Vol. 11, pp. 122-123).

OPG submits that a productivity study should be aligned with the actual investments that companies make to improve their efficiency in the industry under study.[149] The fact that PEG's approach does not measure the bulk of the productivity initiatives that OPG and other hydroelectric generators undertake highlights the significant disconnect between PEG's methodology and the reality of the hydroelectric generation industry.

LEI's Study Accounts for Annual Variations in Water Flow

OEB staff argue that the drought in the southwestern United States during the study period may have contributed to the negative productivity trend identified by LEI (OEB staff argument, p. 155). CME makes similar submissions (CME argument, pp. 64-66), and SEC supports OEB staff's submission (SEC argument, p. 120).

There is no basis to conclude that water conditions in California or elsewhere negatively impacted the productivity trends identified in LEI's study. The record shows that LEI's results were not affected by the drought or other climatological conditions. During the hearing, LEI confirmed that two of the utilities in the peer group experienced a single low-water year in 2014, and that those same utilities experienced several exceptionally wet years during the study period. On balance, the effect of climatological conditions was to increase generation (and productivity) above the long-term average (Tr. Vol. 10, p. 161-162, lines 23-28 and 1-6). By using a geographically diverse peer group over a sufficiently long study period, LEI's study allows for the different hydrological experiences of each peer to be balanced out in the final industry TFP result (Tr. Vol. 10, p. 162, lines 18-27).

OEB staff also imply that the result of LEI's TFP study is influenced by water conditions that are reflected in the MWh output metric, and that trend is somehow incompatible with OPG's experience (OEB staff argument, p. 155). However, both assertions are incorrect. A review of

[149] As noted above, every study reviewed by both experts uses MWh as an output measure; none use MW as the sole output measure (as PEG proposes).

the input and output indices that drive LEI's TFP study confirms that, even if LEI's output index was held constant at 0% over the study timeframe (i.e., all volatility in water conditions was eliminated), the resulting average TFP trend for the industry would still be negative.[150]

Like OEB staff, SEC agrees that "the obvious best output would be M[W]h normalized for water conditions" (SEC argument, p. 120, footnote 547). However, SEC argues that LEI cannot adjust for volatility in hydrology without skewing results (*Id*.). Again, SEC's submission is inconsistent with the evidence. LEI identified three corrective actions it took to address potential year-over-year variations in production (Ex. A1-3-2, Attachment 6, p. 18):

1. LEI checked for anomalies in hydroelectric output relative to the long-term average and excluded utilities who[se] power generation fleet experienced unusual water conditions during the study timeframe that would bias the results.

2. LEI used a relatively long timeframe that "averaged" out year over year oscillations in output and limited the impact of any single year's contribution to the calculated average TFP growth rates.

3. LEI used a trend regression method to re-estimate the average TFP growth rate from the annual TFP Index values in order to remove the bias associated with the TFP Index values at the endpoints of the study timeframe.

SEC's concern is addressed by the first of LEI's three-part validation exercise. As part of their study, LEI assessed each peer's generation levels and eliminated those that experienced abnormal production that could potentially skew the results. Through its analysis, LEI confirmed that one peer did experience an extended period of lower-than-average production, and removed it from the study (Ex. A1-3-2, Attachment 1, p. 37).

12.2.5 LEI's TFP Methodology is More Accurate and More Transparent than PEG's

LEI's Methodology Does Not Require any Depreciation Assumptions

OEB staff argue that the methodology of LEI's study is similar to PEG's monetary approach, if it were to use a one-hoss-shay depreciation profile (OEB staff argument, p. 153). That is incorrect. While the productivity factor that results from LEI's study is closer to a monetary study using one-hoss-shay depreciation (in that both identify negative productivity in the

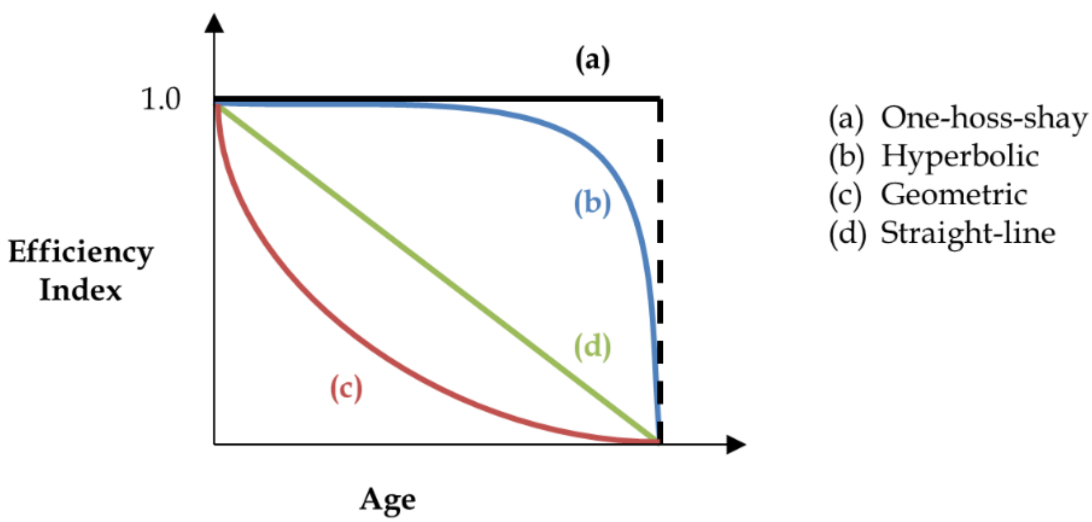
[150] Specifically Figures 25 and 26 in the prefiled evidence (Ex. A1-3-2, Attachment 1, p. 43). In addition, LEI has confirmed the trend of OPG's MWh is similar to that of the industry (Ex. J9.1).

industry), LEI's approach is fundamentally different from PEG's monetary approach. Unlike PEG, LEI's approach does not require the OEB to accept a one-hoss-shay depreciation pattern or to make any other assumptions about the depreciation of hydroelectric assets.

Under its monetary approach, PEG must make an assumption about the depreciation trajectory that hydroelectric assets exhibit. As the evidence shows, the depreciation profile that PEG assumes can significantly affect the outcome of the study. When PEG applied a one-hoss-shay depreciation profile to their study, the TFP trend for their preferred model changed from +0.29% to -0.15% (Ex. M2-11.1-OPG 2, Attachment A, p. 19). However, a physical approach like LEI's method does not require any assumptions about the depreciation of the assets under study. This is a key strength of LEI's approach.

LEI and PEG agree that a TFP study must accurately reflect the actual, physical decay of the assets being studied (Tr. Vol. 11, p. 79, lines 19-21). However, there has been significant debate over the right depreciation profile to apply. LEI provided an illustration of some of the possible depreciation profiles in Ex. A1-3-2, Attachment 6, p. 6, which is reproduced as Figure 12.1, below.

Figure 12.1



PEG's study employs a geometric decay profile (line c), which assumes that OPG's hydroelectric assets depreciate at a constant rate each year. PEG's assumption is inappropriate and does not reflect the assets under study. Hydroelectric generating assets do not deprecate at anything close to a constant rate. The civil structures that make up a hydroelectric station (i.e., the dam itself) represent approximately 70% of the invested capital, and may last for up to 150 years with limited maintenance. These facilities do not decline gradually – they continue to operate at their design levels for decades (Ex. A1-3-2, Attachment 6, pp. 7-8). The evidence shows that a one-hoss-shay depreciation profile better represents the physical depreciation of a hydroelectric station in a monetary productivity study (Tr. Vol. 9, p. 29, lines 4-15).

PEG's incorrect use of the geometric decay profile is primarily responsible for the positive TFP trend they identify. If PEG were to use any lower depreciation rate assumption (i.e., lines a, b, or d), the resulting TFP factor would be more negative (Ex. A1-3-2, Attachment 6, p. 15). Since PEG incorrectly assumes that hydroelectric generators' capital input quantities decline at a constant rate, they conclude that hydroelectric operators use less capital inputs to produce the same level of output, which PEG defined as MW. In other words, by using a monetary approach to capital input quantity measurement in combination with a geometric decay profile, PEG inflates the TFP results in their study.

OEB staff submit that a one-hoss-shay depreciation profile may be appropriate for an incandescent light bulb, but not for a hydroelectric generating station (OEB staff argument, p. 154). However, OEB staff's position is directly contradicted by the Organization of Economic Cooperation and Development ("OECD") capital research manual that PEG cited in its reply memo (Ex. M2, Attachment 1, p. 6). PEG cited the following passage from the OECD manual in a submission to the Australian Energy Market Commission in 2009 (but notably not in its submission here):

> Light bulbs are sometimes cited as potential one-hoss shays, but light bulbs are too short-lived to be classified as capital goods. <u>More serious contenders might be bridges or dams</u>. (Ex. K11.3, p. 25 (emphasis added)).

As the OECD manual indicates, lightbulbs are poor examples of one-hoss-shay depreciation, but that hydroelectric facilities, which are comprised mostly of long-lived civil assets like dams, are a much better example. Dams and other civil structures are not worn-down or consumed through use – they do not decay at a steady rate, as PEG's study assumes. A dam can produce the same energy for many decades with minimal repair. Some components, like electronics or rotor blades, may need replacement, but not the civil structure that comprises over 70% of the asset.[151]

The OECD manual also states that, "with a constant level of maintenance, [dams and other one-hoss-shay capital goods] may continue to provide constant rentals for very long periods of time" (Ex. K11.3, p. 25). This is consistent with LEI's evidence that a one-hoss-shay depreciation profile is a better representation for OPG's hydroelectric capital quantities. As Ms. Frayer testified, assets that follow a one-hoss-shay depreciation profile are not necessarily abandoned or ignored during their lifetimes – they still must be properly maintained. (Tr. Vol. 9, p. 50, lines 15-17).

PEG seems to switch positions and contradict itself on the appropriate depreciation profile between proceedings. During the hearing, PEG stated that one-hoss-shay depreciation would apply to the electric distribution sector (Tr. Vol. 11, p. 14, lines 16-19). However, when PEG was advising the OEB on implementing the RRFE for the distribution sector in 2013, it used a geometric depreciation rate for the electric distribution sector.[152] Similarly, in PEG's submissions to the Australian Energy Market Commission, it stated that energy network assets (i.e., distribution assets) are not characterized by one-hoss-shay depreciation (Ex. K11.3, p. 25).

Critically, all the issues and assumptions discussed in this section are relevant only to PEG's monetary TFP methodology. LEI's study, in contrast, uses universally available engineering data as the capital input quantity.[153] And, while there has been significant debate throughout this proceeding on the appropriate assumptions and data required for PEG's monetary approach, no party has questioned the availability or accuracy of the Maximum Continuous Rating values that LEI's physical approach uses to measure the capital input quantities. LEI's approach is based on the actual capital assets used to generate electricity, which provide a

[151] International Energy Agency, Technology Roadmap: Hydropower, 2012, p. 47, as cited in Ex. A1-3-2, Attachment 6, p. 7.

[152] Empirical Research in Support of Incentive Rate Setting in Ontario: Report to the Ontario Energy Board, May 2013, p. 18. Available online at: http://www.oeb.ca/oeb/_Documents/EB-2010-0379/EB-2010-0379_PEG_Report_20130503.pdf.

[153] Maximum Continuous Rating (the unit's capacity in MW).

rigorously tested, accurate, and current measure of the amount of capital that is employed at each power plant in the study (Tr. Vol. 9, pp. 25-26, lines 22-28 and 1-2).

LEI's Study Accounts for the Productive Investment of Capital

SEC states that, since LEI's study uses capacity as a measure of capital input quantities, it does not account for the productive use of capital dollars (SEC argument, para. 10.3.21). SEC argues that LEI effectively assumes that "the cost of a unit of hydroelectric capacity is the same for all companies in the proxy group" (SEC argument, para. 10.3.19). SEC's argument, misdirected as it is, applies to PEG's approach more than it does to LEI's.

LEI's approach to measuring capital input quantities does not require estimating a unit price of capital, since the physical measure is naturally in quantity terms (MW). SEC also argues that LEI's approach cannot account for capital productivity. That is not true. Examining the input and output index growth rates that drive LEI's TFP study, specifically Figure 26 in the prefiled evidence (Ex. A1-3-2, Attachment 1, p. 43), shows that the ratio of the growth rates for the output (MWh) index to the growth rate in the capital (K) input index is positive for seven of the twelve periods listed. These positive ratios demonstrate capital productivity improvements.

In contrast, PEG assumes that the same capital input price index applies to all peers in its study, and therefore PEG's analysis cannot capture whether one company may have used lower cost input capital. During the hearing, PEG said that a potential benefit of the monetary approach is that one "can break down input quantities into categories with different prices and the more you do that, you are getting more accurate. And price -- decisions to use lower price assets do become a quantity impact." (Tr. Vol. 11, p. 82, lines 8-12). However, under cross-examination, PEG admitted that its analysis did not capture this element because they "didn't have the data to do it." (Tr. Vol. 11, p. 83, lines 3-4).

Confusingly, PEG then claimed that it did not need to break down capital input quantities because the geometric decay assumption for depreciation would act as proxy for those data. However, the geometric decay parameter cannot provide more accurate information on capital quantities since PEG simply applied the same assumption to all peers. In fact, PEG erroneously used OPG's specific composition of assets and historic depreciation study to estimate a depreciation factor and then applied that factor to all peers, without distinguishing the age and composition of assets in each peer's portfolio (Tr. Vol. 11, p. 105, lines 3-9).

In effect, PEG did exactly what SEC incorrectly accuses LEI of doing: PEG assumes that all the generators in its study had the same composition of assets and historical depreciation as OPG.

SEC Confuses Accounting with Productivity

SEC argues that the productivity of OPG's regulated hydroelectric business naturally increases as its hydroelectric rate base depreciates (SEC argument, pp. 121-122).[154] SEC is incorrect. Hydroelectric assets do not become more efficient or more productive because their accounting net book value has declined. As illustrated below, if the OEB were to adopt SEC's theory of productivity, the result would be to reduce OPG's incentive to improve its productivity, which ultimately would negatively affect customer outcomes.

SEC conflates accounting concepts with the measurement of physical productivity. In a competitive market, no company evaluates its productivity, or that of its industry, by the net book value of its assets. Rather, it measures its productivity by the flow of goods or services it can generate from its assets. PEG and LEI agree on this point: the purpose of a productivity study is to measure the physical decay of a company's assets against the outputs it produces (Tr. Vol. 11, p. 84, lines 16-20). Productivity studies are not concerned with the accounting depreciation of assets. Unlike SEC's approach, neither LEI nor PEG's analyses use the net book value of the capital, nor would any credible TFP study.

SEC's proposed approach to measuring productivity based on net book value and accounting principles conflicts with the reality of how generators monitor and work to improve the productivity of their stations. SEC's theory is that, as a company's invested capital is "recovered" through depreciation over an asset's accounting life, it necessarily becomes more productive.

[154] CME makes a similar connection between accounting depreciation and the measurement of productivity (CME argument, para. 355).

A simple example helps illustrate why SEC's idea bears no resemblance to actual productivity at hydroelectric generating stations:

- Imagine a generating station that cost $100, produces 100 MWh per year, and has a 100-year accounting life that depreciates on a straight-line basis at 1% per year.
- In the first year of its life, the station produces its full 100 MWh and is undepreciated. This is the baseline for its productivity: $100 in, 100 MWh out, or 1:1.
- Fifty years later, the depreciated cost of the station would be $50. Assuming it is still operating at its design capacity, the station's productivity would be measured as $50 in, 100 MWh out, or 1:2. Under SEC's theory, the station has doubled its productivity, simply by getting older.

Of course, this is not how productivity and efficiency is achieved or measured in the hydroelectric generating industry. In practice, OPG and other hydroelectric generators work hard and invest significant resources in maintaining and increasing the availability and overall cost-efficiency of their stations. That is the true measure of a facility's productivity. As noted above, LEI and PEG agree that this true, physical decay of a company's facilities is what TFP studies attempt to measure. In contrast, if SEC's approach were correct, OPG could abandon its maintenance programs and allow its stations to decay and their performance to decline. As long as the rate of depreciation outpaced the rate of declining performance, the station would show positive productivity growth. That irrational result underlines the fact that a productivity factor based on SEC's theory would produce perverse outcomes for customers.

The Australian Energy Regulator Supports the Physical Method

During the hearing, PEG acknowledged that the Australian Energy Regulator ("AER") had selected a physical approach to measuring capital input quantities instead of a monetary approach (Tr. Vol. 11, p. 97). Under cross-examination, PEG's witness, Dr. Lowry, stated that the AER had selected a physical approach because of data limitations, but he was unable to find support for that conclusion in the AER's report. He also speculated that the AER's consultant may have exerted some influence over the regulator, and may have "ghost-written" passages of the AER's report (Tr. Vol. 11, p. 98-99).

OEB staff returned to this issue in their submissions, citing a passage from the AER report as support for Dr. Lowry's statement that the Australian regulator had selected a physical approach over a monetary approach due to concerns with the availability and quality of financial data (OEB staff argument, p. 153). A review of the passages quoted by OEB staff shows that they do not make any reference to data quality or availability. The quoted sections of the AER report only state that their consultant had recommended further investigation of these methods. In fact, on the preceding page of its report, the AER clearly states the basis for its decision to use a physical capital measure, without reference to any data quality or availability concerns:

> We support Economic Insights' recommendation to use physical capital measures to proxy the annual capital service flow. That is, before allocating the cost of assets over multiple years, it is necessary to estimate the quantity of capital inputs used in the production process each year. This is also known as the flow of capital services. (Ex. K11.3, p. 12)

12.2.6 Energy Probe's Submissions on Hydroelectric Productivity are Not Based on Evidence and Should be Rejected Outright

EP's arguments on the hydroelectric productivity factor span over twenty pages, in support of a single recommendation on Issue 11.1: neither expert has identified a TFP trend that the OEB can rely on for IR, but if the OEB has to pick one, it should pick PEG's because the year-over-year results are less variable (EP argument, paras. 7.68 and 7.100).

Despite clear direction from the OEB not to do so, EP passes off its own compendium as evidence. EP's submissions are based on EP's own "Note on Data Aggregation", which was included in its compendium for cross-examination of OPG's Panel 2Ai on March 21st, 2017 (Ex. K10.1). EP continually cites its "Note" as evidence of flaws in both experts' reports.[155]

During the hearing, the OEB directly warned EP that it could not cite its "Note" as evidence. Member Spoel advised Dr. Schwartz that,

> if you're proposing to file argument using these numbers… <u>there is no evidentiary basis in this hearing for us to make any use of that information</u>. … I hope you're planning to provide some evidentiary basis upon which that can be done, as opposed to… doing it in argument, because that's not evidence. (Tr. Vol. 10, p. 29, lines 14-25 (emphasis added)).

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[155] This pattern recurs so often in EP's submissions that it would be impractical to list each reference to EP's note here. On reviewing section 7 of EP's submissions, the continual reliance on EP's "Note" is clear.

Despite the OEB's warning, EP has done exactly what it was instructed not to do. EP's submissions are so heavily reliant on its "Note" that OPG was unable to identify a single submission that was not somehow based on this "Note." The OEB therefore should not rely on EP's submissions.

Leaving aside their evidentiary flaws, EP's submissions provide little helpful guidance. EP concludes:

- that neither expert can be relied upon (EP argument, para. 7.68);
- but that the OEB should nonetheless accept PEG's 0.29% TFP growth rate (EP argument, para. 7.100) despite concluding that PEG's study shows a declining and ultimately negative productivity trend (EP argument, paras. 7.53-7.54), that the final 0.29% TFP growth rate result is "statistically insignificant" (EP argument, para. 7.63) and that PEG's approach "may provide an unreasonable TFP growth rate" in future proceedings (EP argument, para. 7.99).

OPG submits that EP's submissions are internally inconsistent and unhelpful. EP's submissions amount to an untested statistical critique of both experts' index-based (i.e., non-statistical) TFP studies, providing the OEB with no useful information. They should be disregarded.

12.2.7 Conclusion: OPG's Proposed Productivity Factor is Appropriate

The 0% productivity factor proposed by OPG is appropriate for the 2017-2021 IR term. On balance, the expert evidence indicates that the hydroelectric industry's productivity trend is negative. LEI's study found a -1% TFP trend. PEG's study found a moderate positive TFP trend, but one that becomes negative if either the output measure or depreciation assumption is adjusted. Therefore, by either expert's TFP method, the 0% productivity factor that OPG proposes is reasonable and consistent with the evidence.

12.2.8 The Proposed Regulatory Materiality Threshold is Appropriate

Several parties have proposed increasing OPG's regulatory materiality threshold from the $10M used in this and prior applications. The proposals cover a range of values, with the highest being $25M proposed by CCC (CCC argument, p. 40).

While the parties focus on the implications of the materiality threshold on potential Z-factor applications, a regulatory materiality threshold determines more than merely the treatment of unforeseen events. For example, OPG's materiality threshold affects the information included in the company's Impact Statements, when an Accounting Order is required, and when an evidentiary update is required under section 11.02 of the OEB's Rules of Practice and Procedure. OPG continues to believe that a $10M regulatory materiality threshold remains appropriate for all of the purposes described above.

OPG also notes that the materiality threshold for electricity distributors is subject to a $1M ceiling. Even if a distributor's service revenue requirement would justify a significantly higher materiality threshold, the OEB determined that $1M should be the maximum materiality threshold. Like OPG, electricity distributors have a single materiality threshold (i.e., they do not have a separate materiality threshold for evidence and for Z-factors) (Ex. J8.2).

A $10M materiality threshold continues to be appropriate for OPG's regulated hydroelectric business. In response to interrogatory Ex. L-11.1-5 CCC-47, OPG provided a detailed explanation of how the company's regulatory materiality threshold was established, and what it would look like using different vintages of financial inputs. As illustrated in that response, although OPG's hydroelectric rate base has grown since the materiality threshold was first established, using more current inputs would result in a regulatory materiality threshold for that is not significantly different from the $10M value.

12.3 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?

There is an agreement to settle this issue (Ex. O-1-1, p. 15; Tr. Vol. 9, p. 1).

12.4 Nuclear

12.5 Issue 11.3

Oral Hearing: Is OPG's approach to incentive rate-setting for establishing the nuclear payment amounts appropriate?

OPG has proposed a Custom IR framework for the company's nuclear facilities that is consistent with OEB policy, recognizes that both Darlington and Pickering are undergoing significant changes during the IR term and supports the continued safe and reliable operation of these facilities. In particular, it is consistent with the OEB's expectation that OPG should develop a Custom IR framework for its nuclear assets based on the principles outlined in the RRFE, as set out in the OEB's February 17, 2015 letter.

OEB staff submit that OPG's Application "generally meets the standards" for a Custom IR plan, (OEB staff argument, p. 167). However, CCC, LPMA and SEC believe that OPG's Custom IR proposal should be denied by the OEB because in their view, OPG's plan is inconsistent with the OEB's guidance on Custom IR and is more akin to a five-year Cost of Service plan with IRM elements (e.g., CCC argument, p. 43). As set out in Ex. A1-3-2 and as explained in the following paragraphs, OPG's proposed Custom IR framework reflects guidance from the OEB in that it incorporates both the principles of the RRFE and the unique circumstances of OPG's nuclear facilities during the IR term. OPG concurs with OEB staff and submits that the position taken by CCC, LPMA, and SEC is contrary to the evidence and should be rejected.

LPMA submits that OPG's non-DRP and non-PEO nuclear costs should be subject to a standard "I-X" price-cap IRM regime (LPMA argument, pp. 42-44).[156] Before embarking on its substantive refutation of LPMA's points, OPG notes that these points appear for the first time in LPMA's argument. Despite the fundamental changes that LPMA would make to OPG's Custom IR, it never raised any of these points with OPG's witnesses in cross examination or asked interrogatories about them. Thus OPG is left to address these matters here, for the first time. This approach to regulatory hearings is at odds with the OEB's determination: "that parties have the right to know and answer the case they have to meet." (A Report with Respect to Decision-Making Processes at the OEB, September 2006, p. 26). OPG respectfully requests that the OEB reject LPMA's tactic as inconsistent with procedural fairness.

The OEB should reject LPMA's proposal because it is inconsistent with the OEB's report entitled, Incentive Rate-making for Ontario Power Generation's Prescribed Generation Assets

[156] LPMA submits the costs associated with the DRP and PEO should be dealt with on a cost of service basis (LPMA argument, p. 40).

(the “IR Report”) issued on March 28, 2013 following the EB-2012-0340 consultation. In the IR Report, the OEB was clear that it would not be appropriate for OPG to adopt a “pure IR” regime for the nuclear facilities, based on TFP with input cost indices and other features of a price-cap IR framework until the DRP and Pickering closure were complete (IR Report, pp. 8-9).

Intervenors’ submissions that OPG’s Custom IR proposal is inconsistent with the OEB’s October 13, 2016 Handbook for Utility Rate Applications (e.g., LPMA argument, p. 40) are also inappropriate. As OEB staff note, OPG’s Application was filed almost six months before this Handbook was issued (OEB staff argument, p. 167). OPG respectfully submits that it would be inappropriate and unfair to retroactively apply any new requirements from the Handbook to OPG’s Application. In any case, OPG’s view is that its Custom IR plan does reflect OEB policy by virtue of being consistent with the RRFE, as explained below.

The evidence does not support intervenors’ submissions that OPG’s nuclear rate-setting framework is effectively a Cost of Service plan that doesn’t adhere to RRFE principles (e.g., CCC argument, p. 43). OPG has developed a Custom IR plan that is based on specific forecast costs and production from a challenging business plan, further reduced by a benchmark-based stretch factor that decouples rates from costs (the stretch factor is discussed further below). OPG’s proposed Custom IR framework has been informed by various sources, including the OEB’s 2012-2013 consultation on incentive rate-making for OPG (EB-2012-0340). Its five-year term is consistent with OEB policy (see AIC, p. 167), a point which no party disputes and which OEB staff support (OEB staff argument, p. 168).

Moreover, the proposed nuclear Custom IR framework is layered on top of a nuclear rate structure that necessarily creates a strong incentive for OPG to continually improve its productivity and cost-efficiency. Unlike electricity and gas distributors, OPG’s nuclear payments are 100% variable, meaning that the company’s revenues vary directly with the amount of electricity it produces from the nuclear facilities. Even without the proposed nuclear stretch factor (discussed further below), OPG has a very strong financial incentive to operate as efficiently as possible, since any decrease in reliability or increase in cost directly reduces the company’s net income (Ex. A1-3-2, section 3.4).

OPG’s Custom IR proposal does not include a nuclear industry productivity factor, consistent with the IR Report. No parties opposed this aspect of OPG’s proposal. PWU submits that not including a productivity factor is appropriate (PWU argument, para. 161), while AMPCO does not object (AMPCO argument, para. 269). Moreover, OEB staff submit that it would be "challenging" to do so (OEB staff argument, p. 167).

OPG proposes that unforeseen events affecting the nuclear business continue to be addressed through an accounting order process, subject to the $10M regulatory materiality threshold that has historically applied to OPG (Ex. J8.2). Several intervenors believe that this materiality threshold is out of date and needs to be revised. CCC submits that a Z-factor should be applied to nuclear and hydroelectric facilities on a combined basis and that the combined threshold should be $25M (CCC argument, p. 44). LPMA and SEC submit that a nuclear-specific threshold should be used, based on the nuclear revenue requirement and rate base, which would result in threshold value between $12.1M and $16.8M per Ex. J8.1 (LPMA argument, p. 48; SEC argument, para. 10.9.22). In OPG's view, its $10M materiality threshold, which is also used in determining whether to include items in an Impact Statement, remains appropriate and should be accepted by the OEB. Please also see OPG's submissions on the proposed hydroelectric materiality threshold in Issue 11.1 (Section 12.2.8).

Several intervenors made a number of submissions on other aspects of OPG's Custom IR proposal (e.g., annual ROE update, interaction between the CRVA and other aspects of the Custom IR plan, mid-term production review and off-ramp), which contribute to their view that OPG's Custom IR proposal should be rejected by the OEB. These submissions are addressed under Issues 9.8, 9.2, 11.5, and 11.7 in Sections 10.8, 10.2, 12.7 and 12.10, respectively. For the reasons outlined in those sections, the OEB should reject intervenors' submissions and find OPG's Custom IR proposal appropriate. The remainder of this section focuses on OPG's nuclear stretch factor proposal.

OPG has proposed a nuclear stretch factor based on the annual nuclear benchmarking process that has been accepted by the OEB. The proposed stretch factor was calculated based on the two nuclear stations' individual performance on the key "value for money" metric: Total Generating Cost per MWh ("TGC/MWh"), per the 2015 Nuclear Benchmarking Report. OPG weighted the quartile ranking of each station by their respective shares of total nuclear forecast production, resulting in a stretch factor value of 0.3% (Ex. A1-3-2, pp. 31-33).

OEB staff and a number of intervenors (AMPCO, CCC, EP, LPMA, SEC and VECC) support OPG's use of TGC/MWh to develop the nuclear stretch factor. Despite the general consensus around using TGC/MWh, the parties propose two changes that have the effect of increasing the stretch factor, both of which are addressed below:

1. Using a more simplistic comparison of OPG's overall nuclear TGC/MWh against the consolidated facilities of other major nuclear operators, which does not adequately reflect the performance of Pickering and Darlington in the context of each station's unique circumstances.
2. Using the 2015 TGC/MWh results from the 2016 Nuclear Benchmarking Report as the basis for the stretch factor, despite the evidence that it is less representative of the facilities' performance.

Overall Nuclear TGC/MWh Does Not Properly Reflect the Nuclear Stations' Performance

Instead of calculating station-specific stretch factors for the two nuclear facilities as OPG has done, and which PWU supports, the parties propose a stretch factor of 0.6% based on OPG's overall nuclear TGC/MWh relative to other major nuclear operators (e.g., OEB staff argument, pp. 168-169).

This proposal does not address the evidence that the stretch factor would more accurately reflect OPG's performance if it were calculated based on the specific performance of each station and weighted by each station's share of production (Ex. L-11.4-1 Staff-256). As OEB staff acknowledge, it is not reasonable to expect Pickering to achieve first or second quartile performance (OEB staff argument, p. 88). As discussed extensively under Issue 6.2 (Section 7.2), historical and projected future performance at the Pickering station is limited by the size of units, the first generation CANDU design, and the reduction in capability factor during the outages required to enable Extended Operations (Ex. F2-1-1, pp. 3-5). While Pickering has been able to maintain stable TGC/MWh even as peers in the top quartile and median experienced significant growth (also discussed further in Issue 6.2 under Section 7.2), OPG submits that these same factors limit the opportunity for efficiency improvements at the Pickering station, a view which PWU also holds (PWU argument, para. 168).

The parties' approach to calculating the stretch factor does not properly reflect the actual performance of the nuclear stations. Rather than looking at the benchmark performance of each OPG facility, this simplified approach only considers "major operators" (i.e., those with multiple stations and therefore removing seven single station operators, as detailed at Ex. F2-1-1, Attachment 1, p. 98). This limitation allows parties to conclude that OPG was 10th out of 13 operators in 2014. However, as noted in the ScottMadden methodology, calculating the stretch factor by reference to the major operator summary provides a less complete picture of plant by plant performance (Ex. F2-1-1, Attachment 1, p. 84).

By relying on overall TGC/MWh reflected in the major operator summary, OEB staff's approach unduly amplifies the inherent limitations of the Pickering station. A stretch factor based on overall TGC/MWh, does not reflect the historic performance or realistic improvement opportunities available at either nuclear station. Under the parties' approach, the calculation of the stretch factor would have resulted in a disproportionately high value during 2010-2014 when Darlington was a top performer in the industry and was the source of the majority of OPG's nuclear production. The parties' arguments do not address these issues.

SEC submits that the stretch factor should be based on overall nuclear TGC/MWh since ratepayers pay one single nuclear payment amount (SEC argument, para. 10.9.9). OEB staff note that, while customers ultimately pay for the nuclear business as a whole, it is also appropriate for OPG to set separate targets for the Darlington and Pickering stations (OEB staff argument, p. 84). OPG agrees with OEB staff, and has calculated the stretch factor in a way that balances both points. By weighting the stretch factor according to the production of each station, the stretch factor accurately reflects the performance of OPG's combined nuclear fleet, while still providing an incentive for OPG to improve performance at both facilities.

The consequence of the parties combined approach would be to encourage OPG to focus all its efforts on improving performance at Pickering, despite the fact that the station will cease operating in only a few years. With respect, that would be a perverse outcome. The stretch factor should balance OPG's incentive to improve and maintain performance at both stations; if anything, it should emphasize the efficiency of Darlington, which will continue to power Ontario for decades to come.

The 2016 Nuclear Benchmarking Report is Not an Appropriate Basis for the Stretch Factor

It is always important that a stretch factor be determined based on a representative measure of a company's efficiency. In this case, it is even more critical that the stretch factor be based on a realistic measurement of OPG's steady state performance since it will be fixed for the full five-year IR term.

Some parties propose that the OEB use the 2015 TGC/MWh result from the 2016 Nuclear Benchmarking Report as the basis for an increased nuclear stretch factor (e.g., SEC argument, para. 10.9.8). The effect of that approach would be to adopt an unrepresentative, unfairly high stretch factor for all five years of the IR term. As OPG's witnesses noted in the hearing, and as OPG emphasized in its AIC, the one-in-twelve-year VBO (a unique requirement of CANDU stations), the ramp-up in capital spending in conjunction with DRP, along with unbudgeted outages associated with PHT pump motors impacted the Darlington station's performance in 2015 (AIC, section 7.2.2; Tr. Vol. 6, p. 126, lines 4-25).

A number of parties argue that comparator utilities also have planned and forced outages and that TGC/MWh should be minimally impacted by events in any one year, since it is calculated on a three-year rolling average (e.g., OEB staff argument, p. 168). OPG submits that these parties underestimate the significance of the events that impacted Darlington's 2015 performance (see Issue 6.2 at Section 7.2 for further discussion). OPG submits that the 2014 benchmarking results are most reflective of steady state operations and should be used to set the stretch factor over the five-year IR term.

SEC submits that the basis used to determine the production-weighted stretch factor should be forecast production and not actual production (SEC argument, para. 10.9.10). OPG submits that determining the production-weighted stretch factor using forecast production would be inappropriate for the same reason as using 2015 benchmarking performance at Darlington, namely that it does not reflect steady state operations. OPG also submits that SEC's proposal would be inconsistent with the RRFE and the OEB's practice under it. Under the RRFE and the 3GIRM framework, stretch factors are determined based on "the efficiency of a given distributor <u>at the outset of the IR plan</u>."[157] Further, OPG is aware of no other instance in which the OEB has calculated any aspect of a stretch factor based on forecast performance.

[157] Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach. October 18, 2012, p. 17 (emphasis added).

The parties have not provided an analytic basis for the 0.6% stretch factor they propose. For example, OEB staff state that the stretch factor "could be as high as 0.6%" but do not provide a clear basis for that conclusion (OEB staff argument, p. 168). The parties' proposal appears to be based entirely on ranking OPG's overall TGC/MWh against the major operators in the 2016 Nuclear Benchmarking Report and concluding that, since OPG is low on the list, it should receive the highest stretch factor. In contrast, OPG's production-weighted calculation is more closely tied to the actual performance of the two stations.

Finally, CME argues that benchmarking Darlington's 2014 performance while it is operating in a steady state environment "runs contrary to the purpose of benchmarking and artificially inflates OPG's efficiency performance" (CME argument, para. 403). CME's position is contrary to the evidence. As described above, the 2015 result is not representative of the nuclear facilities' performance during normal operations. OPG's proposal does not "inflate" the company's performance. However, CME's proposal would artificially depress OPG's performance for the purpose of increasing the stretch factor for the entire five-year IR term.

For the reasons discussed above, OPG submits that it is not appropriate to use the 2016 Nuclear Benchmarking Report to determine the stretch factor. However, if the OEB were to determine that the more recent benchmarking report is the proper basis on which to calculate the stretch factor, OPG calculated an updated stretch factor value of 0.43% using the more appropriate production-weighted methodology proposed in the prefiled evidence (Tr. Vol. 6, p. 129, lines 20-21). LPMA's submission that this value should be rounded to at least 0.5% is unsubstantiated and OPG submits that it should be rejected (LPMA argument, p. 47).

The Stretch Factor Should not be Expanded to Additional Cost Categories

OPG has proposed that the nuclear stretch factor apply to nuclear base OM&A and allocated corporate support services OM&A. These categories comprise an average of $1.7B per year, or approximately 75%, of OPG's total nuclear OM&A during the IR term (Ex. A1-3-2, pp. 28-31).

PWU supports OPG's proposed application of the stretch factor (PWU argument, para. 173). OEB staff[158] and CME propose that the nuclear stretch factor should apply to a broader range of OM&A cost categories, even though many of those costs are either non-discretionary or subject to the CRVA. Certain intervenors go further in proposing that the stretch factor should also apply to non-DRP capital (AMPCO, LPMA[159], SEC and VECC) while others go further still and propose that it should apply to all aspects of OM&A and capital (CCC and EP).

The parties propose that the OEB expand the stretch factor to some or all of the following cost categories:

1. Project OM&A and Capital
2. Outage OM&A
3. Darlington Refurbishment OM&A
4. Darlington New Nuclear OM&A
5. Centrally Held Costs
6. Asset Service Fee

OPG submits that it is not appropriate to apply a stretch factor to any of these cost categories. In some cases, it is not reasonable to expect that OPG will be able to realize additional efficiencies, beyond those already incorporated, in these areas. In others, certain eligible costs are covered by the CRVA and it would be inappropriate for the OEB to apply a stretch factor to such costs that will be "trued up" to actual amounts when OPG applies for disposition of the CRVA. OPG notes that OEB staff appropriately propose to exclude Darlington Refurbishment OM&A from the stretch factor on this basis (OEB staff argument, p. 171).

OPG addresses each category individually below.

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[158] In Table 40 of OEB staff's submissions, they present stretch factor amounts proposed by OPG from the prefiled evidence and OEB staff's proposed stretch factor amounts based on the same vintage of data (OEB staff argument, p. 169). As OEB staff note in their argument (*Id*), the amounts shown in Table 40 have been updated in OPG's first Impact Statement (Ex. N1-1-1).
[159] LPMA also exclude PEO-related costs from the stretch factor.

Project OM&A and Capital

OPG's evidence is that the activities that make up this category are unique so that work does not repeat between projects (Tr. Vol. 6, p. 138, lines 21-26). OEB staff, AMPCO and CME assert that there may be some elements of repetition between projects, perhaps in project management and administration (OEB staff argument, p. 170; AMPCO argument, para. 265; CME argument, paras. 414-415). OPG submits that management and administration make up a very minor component of project OM&A and capital expenditures.[160] The record does not identify efficiency opportunities that could apply to the vast majority of project-related costs, nor is OPG aware of any opportunities that could potentially satisfy the reduction in funding that would result from applying the stretch factor to project OM&A and capital.

As it stands, OPG's capital spending is already very efficient, having benchmarked in the top quartile from 2010-2015 on the capital expenditure per megawatt metric (Ex. L-6.2-15 SEC-63, Attachment 3, pp. 81-83).[161]

Moreover, OPG's portfolio management process already creates a strong incentive to execute project work as cost efficiently as possible (Tr. Vol. 6, pp. 138-139). This is because a considerable portion of OPG's project budgets is not earmarked for specific projects and OPG currently has more projects in its project pipeline than can be accommodated by its annual budgets. As a result, the more efficient OPG is at project execution, the more projects OPG is able to carry out within its portfolio budget. Executing a greater number of projects successfully leads to greater reliability and ultimately to increased production and operating revenue. OEB staff's assertion that these conditions also apply to large distributors (OEB staff argument, p. 170) is unsubstantiated and in any case does not dispel the notion that OPG already has a significant incentive to be efficient within its project funding envelope.

While OEB staff do not propose to apply the stretch factor to capital, they do believe it should apply to project OM&A. OEB staff's position on project OM&A is inconsistent with its position on the treatment of CRVA-eligible costs. OEB staff submit that the costs of several nuclear

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[160] For example, OPG's project management costs as a percentage of total project costs are only about 7% for Tier 1 projects in total (Ex. JT2.08, calculated by dividing aggregate updated OPG project management estimate in col. (j) by aggregate total project cost estimate current BCS in col. (h)).

[161] As the benchmark is $/MW, top quartile performance means that in 2015 OPG spent less per MW on capital than the other nuclear generators in the comparator group.

projects are eligible for inclusion in the CRVA (OEB staff argument, pp. 23-24). These include project OM&A related to the DRP, PEO, and other projects (OEB staff argument, pp. 33-35).[162] OEB staff exclude Darlington Refurbishment OM&A from the stretch factor since those costs are included in the CRVA, but do not acknowledge that a significant proportion of project OM&A is also subject to CRVA treatment.

OEB staff's submission that the "compatibility with the CRVA was not sufficiently tested in this proceeding" contributes to their proposed exclusion of capital from the stretch factor (OEB staff argument, p. 170). LPMA's assertion that OEB staff's submission is not valid appears to reflect LPMA's view that the stretch factor should not be applied to DRP and PEO-related costs (LPMA argument, p. 46). OPG submits that all CRVA-eligible costs, including project OM&A and capital costs, should be excluded from the stretch factor for the reasons provided above.

Several intervenors refer to the OEB's Decision in Toronto Hydro's EB-2014-0116 application as support for their belief that the stretch factor should also be applied to capital (e.g., EP argument, para. 6.20). In that Decision, the OEB stated that it "has consistently applied stretch factors to total costs in order to incent productivity in both the areas of capital expenditure and OM&A. The OEB finds no compelling reason to depart from this approach." (EB-2014-0116 Decision and Order, p. 18). However, in OPG's view, the application of the stretch factor is less amenable to the large discrete projects that OPG executes as compared to the mainly routine and repetitive projects that distributors carry out (Tr. Vol. 6, p. 138). Hydro Ottawa's EB-2015-0004 proceeding provides an example where the OEB did not apply the stretch factor to capital (OEB staff argument, p. 170). Based on this precedent, and for the reasons provided above, OPG respectfully submits that the OEB should not apply the stretch factor to capital in OPG's case either.

CME, EP and SEC submit that if the OEB finds that the stretch factor only applies to OM&A, then TGC/MWh may not be an appropriate basis for determining the stretch factor because it includes a capital component (CME argument, paras. 425-426; EP argument, para. 6.23; SEC argument, para. 10.9.16). This contention is contrary to the evidence, which shows that TGC/MWh is the best available metric to establish a nuclear stretch factor for OPG's nuclear facilities since it is an "all-in" measure of the cost of operating the nuclear facilities. The 2015

[162] Virtually all of the PEO costs during the IR term are either project OM&A or outage OM&A.

Nuclear Benchmarking Report describes nuclear TGC/MWh performance as the "best overall financial comparison metric for OPG facilities." (Ex. F2-1-1, Attachment 1, p. 66). For this reason, OPG submits that TGC/MWh is the appropriate metric to use even for a stretch factor that applies only to OM&A.

Outage OM&A

Outage OM&A costs are tied to specific outages, and "vary year over year depending on the number and scope of outages and therefore cannot be trended over time" (Ex. F2-4-1, p. 1, lines 7-8). Like projects, outages are unique planned work – they are not a steady state function that occurs on a consistent basis, year-over-year (Tr. Vol. 14, p. 17, lines 1-7). As a result, AMPCO's submission that outage work requirements are "repetitive and suitable for improvements" (AMPCO argument, para. 267) is contrary to the evidence and should be rejected by the OEB. CME submits that OPG's targeted improvement in various outage planning areas (e.g., creating an outage model template) will lead to efficiencies that would allow the stretch factor to be applied to outage OM&A (CME argument, paras. 416-418). However, this is incorrect as OPG's targeted improvements will only enable it to achieve the challenging targets it has set in the 2016-2018 Business Plan, not achieve additional efficiencies (Tr. Vol. 14, p. 11).

As noted in Ex. A1-3-1, the stretch factor reduction is cumulative, on the presumption that efficiency gains are sustained in each subsequent year of the IR term. However, since outages are not recurring events, it is not reasonable to assume that OPG will realize repetitive efficiency improvements for individual planned outages (Tr. Vol. 14, p. 17, lines 8-13). A cumulative stretch reduction would quickly surpass any potential efficiency gains.

For example, in 2021, there are no major planned outages scheduled at Darlington. A significant proportion of 2021 outage OM&A is for the extensive, station-wide Pickering VBO (Ex. E2-1-1, p. 8). The VBO is a unique, major undertaking that requires taking all six-units at the Pickering station offline, once every twelve years. It is a complex event that clearly illustrates the unique nature of the costs that comprise the outage OM&A forecast. It is not reasonable to apply the stretch factor to this area based on the assumption that OPG will be able to realize some unspecified incremental efficiency improvements in 2021 when there are no major outages at Darlington and while Pickering executes the VBO.

OEB staff have taken an inconsistent position on the treatment of CRVA-eligible costs for outage OM&A and the application of the stretch factor. As discussed above in the context of project OM&A and capital, outage OM&A includes a significant proportion of the costs of PEO, which OEB staff agree should receive CRVA treatment. OEB staff's position is inconsistent with their proposed treatment of Darlington Refurbishment OM&A, which they exclude from the stretch factor because it is subject to the CRVA. The stretch factor should not apply to project or outage OM&A any more than it should apply to Darlington Refurbishment OM&A.

Darlington Refurbishment OM&A

For the reasons discussed above, OPG submits that it would be inappropriate for the OEB to apply the stretch factor to this category of CRVA-qualified costs (OEB staff argument, p. 171).

Darlington New Nuclear OM&A

Although the amounts proposed for Darlington new nuclear OM&A during the IR term are comparatively small, they are subject to the Nuclear Development Variance Account ("NDVA"). Since these costs would be included in the NDVA, it would not be appropriate to apply a stretch factor to them, for the same reasons it is not appropriate to apply a stretch factor to CRVA-related costs, as described in the preceding paragraphs. Further, the costs of increasing or maintaining the ability to expand capacity at Darlington are, by their nature, unique. It is not reasonable to expect OPG to make incremental efficiency improvements in discrete areas like Darlington new nuclear.

Centrally Held Costs

This category consists of several non-discretionary costs. The largest category of centrally held costs during the IR term is IESO non-energy charges, which includes the Global Adjustment and other exogenous non-discretionary fees. Other centrally held costs include pension & OPEB-related accrual costs, and nuclear insurance costs (Ex. F4-4-1, Table 1). These are not operational costs and, by their nature, it will not be possible to realize incremental efficiencies in these areas. For example, the pension and OPEB amounts are a function of actuarial determinations, while the vast majority of the insurance costs are for nuclear liability insurance required by recently updated federal legislation. It would be unreasonable and unfair to reduce funding based on stretch factor savings that cannot be realized.

Asset Service Fee

The asset service fee consists of depreciation expense, certain operating costs, property taxes, and a tax-adjusted return earned on certain real property and IT assets that are held by OPG centrally (i.e., not by individual business units). Since these assets are not included in rate base, the nuclear business is charged a fee for their use (Ex. F3-2-1, p. 1). The facilities and electronic infrastructure funded through the asset service fee are core assets that are necessary to operate the business. OPG does not foresee any opportunity – nor has any party identified one – to make incremental efficiency improvements that would drive down the costs of owning its facilities or IT systems during the IR term.

OPG's Nuclear Rate Design Creates a Significant Financial Incentive

None of the parties have disputed the significant incentive created by the design of OPG's nuclear payment amounts. OPG's nuclear facilities are unique among the entities under incentive rate-setting at the OEB, in that its payments vary directly with the company's output (MWh).

The 100% variable design of OPG's nuclear payment amount creates a very strong, very direct financial incentive for OPG to continuously seek efficiencies and to improve the performance of its facilities (Tr. Vol. 6, p. 140). Unlike a distributor, which has a component of its rates fixed, OPG can more directly affect its revenues by attempting to improve the reliability of its nuclear facilities (Ex. L-6.2-20 VECC-025, p. 1, lines 43-48). The company's nuclear rate design creates a very powerful performance improvement incentive, without the application of a stretch factor.

Achieving OPG's proposed stretch factor reductions will be challenging, especially since the 2016-2018 Business Plan limits the average annual increase in total nuclear operations OM&A to less than inflation (i.e., 0.9% per year) over the 2015-2021 period, before the stretch factor is applied (Ex. F2-1-1, p. 5, line 25).

OPG notes that the parties' proposed adjustments to the size of the stretch factor and its application are in addition to various disallowances proposed to OM&A, compensation and capital (see Issues 4.4, 6.1, 6.6 at Sections 3.1, 7.1, 7.7 respectively, for further discussion).

OPG submits that the OEB should seek to avoid "double counting" when assessing OPG's proposed stretch factor and budgets for OM&A and capital expenditures.

12.6 Issue 11.4

Oral Hearing: Does the Custom IR application adequately include expectations for productivity and efficiency gains relative to benchmarks and establish an appropriately structured incentive-based rate framework?

Please refer to Issue 11.3 (Section 12.5).

12.7 Issue 11.5

Primary: Is OPG's proposed mid-term review appropriate?

As set out in detail in Ex. A1-3-3, section 3, OPG seeks approval to file an application in the first half of 2019 to review and update the nuclear production forecast and corresponding fuel costs for the July 1, 2019 to December 31, 2021 period. To effect this proposal, OPG proposes establishing the Mid-term Nuclear Production Variance Account to record the impact of the production variance from July 1, 2019 to December 31, 2021. This account is proposed to take effect on July 1, 2019 and is further discussed under Issue 9.8 (Section 10.8).

As described in Ex. A1-3-3, section 3, the purpose of the mid-term production review is to mitigate the significant production risk associated with setting nuclear payment amounts over the five-year term of this Application. OPG's 2017-2021 nuclear production forecast is presented in Issue 5.1 (Section 6.1) and Ex. E2-1-1. The production risk is expected to increase during the second half of the five-year term due to the DRP and the work required to enable PEO and the inherent inaccuracy of forecasting further into the future (Tr. Vol. 15, p. 77; Ex. A1-3-3, p. 13; Ex. L-11.5-1 Staff-270).

As part of the mid-term review application, OPG is proposing to seek disposition of applicable audited D&V account balances (Ex. A1-3-3, p. 10; Ex. L-11.5-5 CCC-049).[163,164] If the OEB

[163] Most accounts will reflect amounts accumulated over the three-year period January 1, 2016 to December 31, 2018 as well as any remaining unamortized portions of previously approved amounts with recovery periods extending beyond December 31, 2018, currently the Pension and OPEB Cost Variance Account.

[164] OPG's proposal to seek disposition of applicable deferral and variance account balances, including the CRVA, has been part of OPG's Application since the prefiled evidence was filed in May 2016. Thus, AMPCO's assertion that "When OPG decided to remove the D2O facility from the current application, it also determined that the costs associated with this facility will now be submitted for review at the mid-term review" (AMPCO argument, para. 275)

does not approve OPG's mid-term production review proposal, OPG would still propose to seek disposition of applicable D&V account balances during the IR term.

OEB staff and intervenor submissions on the mid-term review focus on three main areas: (1) the validity of OPG's request to have its production forecast reviewed during the IR term; (2) the scope of the mid-term review; and, (3) the timeframe for the review.

Validity of Production Forecast Review During IR Term

Four intervenors (CME, EP, LPMA, VECC[165] and SEC) take exception to OPG's proposed mid-term production review. For the reasons provided below, OPG respectfully disagrees and notes that in its view, the mid-term production review would be beneficial to both OPG and ratepayers. OEB staff, AMPCO, CCC and PWU agree that a review of the production forecast during the IR term is warranted.[166]

LPMA and SEC argue that OPG's proposed review of its production forecast prior to the completion of the five-year Custom IR term should be rejected by the OEB in principle as being contrary to the OEB's October 13, 2016 Handbook for Utility Rate Applications and to the RRFE (LPMA argument, pp. 50-51; SEC argument, paras. 10.10.2-10.10.5). As discussed further under Issues 11.3 and 11.4 (Section 12.5), OPG submits that since its Application was filed almost six months before the OEB's Handbook was issued, it would be unfair to retroactively apply its requirements to OPG's Application. Moreover, the OEB Handbook does allow for update applications in exceptional circumstances, which in OPG's submission, apply here (Handbook for Utility Rate Applications, p. 26; Tr. Vol. 6, pp. 188-189).

OPG has proposed a Custom IR framework for the company's nuclear facilities that is consistent with OEB policy based on the principles outlined in the RRFE (also discussed further in Section 12.5). Neither the RRFE nor the OEB Handbook specifically preclude a mid-

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is incorrect. Since the costs of the Heavy Water Storage and Drum Handling Facility ("D2O") project are tracked in the CRVA, they have always been included in the review of deferral and variance accounts proposed by OPG as part of the mid-term proceeding, as confirmed by the testimony of Mr. Lyash (Tr. Vol. 2, p. 47). Thus, contrary to AMPCO's claim, this is not an expansion of scope.

[165] VECC states that it supports LPMA's position that no mid-term review should be allowed for the review of OPG's production forecast (VECC argument, para.11.5.1). However, VECC also supports OEB staff's submission, which includes a review of the production forecast for DRP-related impacts.

[166] QMA supports OEB staff's position on Issue 11.5 (QMA argument, p. 10) and will not be mentioned further in this section.

term production review from being part of a Custom IR application. OEB staff acknowledge in their submission that OPG's Application "generally meets the standards" for a Custom IR plan (OEB staff argument, p. 167).

OPG is taking on risks that span the full five-year IR term, notwithstanding the mid-term production review. LPMA's submission that OPG's "Custom IR plan effectively has a term of only 2.5 years" as a result of the mid-term production review is incorrect (LPMA argument, p. 50). The five-year term of OPG's Application covers 2017-2021 revenue requirement and OPG's rate smoothing proposal (discussed further under Issue 11.6 at Section 12.8) proposes nuclear payment amounts for the same five-year period, consistent with the requirements of O. Reg. 53/05. Consequently, LPMA's assertion that OPG's Application "violates" the minimum term of a Custom IR plan per the RRFE is wrong (*Id.*).

LPMA's submission that a potential Z-factor event "negates the need" for the mid-term production review evidences a misunderstanding of the types of events that may qualify for Z-factor or similar treatment (LPMA argument, p. 51). OPG's mid-term production review is designed to address at least five uncertainties, including public policy changes, PEO, DRP, regulatory requirements and approvals, and aging facilities (Ex. A1-3-3, p. 13; Ex. L-11.5-1 Staff-270). Z-factors and similar mechanisms address unforeseen events – a much narrower category than the uncertainties that give rise to the mid-term production review. Therefore, OPG submits that Z-factors and similar mechanisms cannot substitute for the mid-term production review.

CME submits that the mid-term production review is inconsistent with the OEB's EB-2007-0905 Decision that OPG should bear 100% of the production risk associated with its nuclear production forecasts (EB-2007-0905 Decision with Reasons, p. 174). CME contends that the mid-term production review "limits OPG's risk if output falls short of forecast during the second half of the term" and motivates OPG to over-estimate its production during the first half of the IR term and then lower its production forecast for purposes of the mid-term review application (CME argument, paras. 432-433). CME is incorrect on both fronts. First, a mid-term production review is not a proposal to true-up production to actual performance. OPG will continue to bear 100% of the nuclear production forecast risk even if the mid-term production review is approved by the OEB, as OPG's payment amounts are 100% variable. Once a production forecast is adopted, whether in this Application or the mid-term review, the company's nuclear rate design creates a strong production incentive (Ex. L-11.5-1 Staff-261). The mid-term production review would, however, limit production forecast risk to two 2.5-year periods instead of one five-year period. Moreover, CME has only considered risk from the perspective of a shortfall in output during the second half of the term. However, there are other scenarios in which output could exceed the forecast during the second half of the term. Under those scenarios, the mid-term production review would be beneficial to ratepayers.

Second, there is no basis for CME's suggestion that the mid-term production review encourages poor production forecasting. At its core, CME is arguing that OPG's current forecast over-states the amount of production anticipated in the latter half of the IR term, without providing any evidence to support this claim or explaining why OPG would want to over-forecast production. As discussed in Section 6.1, OPG's production forecast methodology produces the company's best view of expected production based on the available information.

In the mid-term production review, OPG anticipates applying the same methodology to the best available information at that time. OPG's production forecast at the mid-term proceeding would be subject to the same degree of regulatory scrutiny that is being applied to the current production forecast. If OPG were to change its production forecast at the mid-term review, either higher or lower, it would have to defend the new forecast before the OEB as it has done in this Application.

CME also argues that OPG's proposed Mid-Term Nuclear Production Variance Account asymmetrically protects OPG, based on OPG's historical overestimation of production since 2008 (CME argument, para. 436). In OPG's view, its nuclear production forecast is a complete and accurate forecast based on a rigourous planning methodology that has been refined over time (see Issue 5.1 in Section 6.1 for further discussion). For this reason, and due to the production-related uncertainties associated with the DRP and PEO, OPG believes that the mid-term production review does in fact provide symmetrical protection to the benefit of customers and OPG.

EP submits that the OEB should reject OPG's mid-term production review proposal because the province did not legislate it and because OPG is not proposing the same type of review for its hydroelectric facilities (EP argument, paras. 9.11 and 9.12). In OPG's view, the fact that the province has not mandated the mid-term review is not a reasonable basis to reject it, as a Provincial mandate is not a necessary requirement for the OEB to approve an applicant's rate-making proposal. Similarly, the fact that OPG is not proposing a mid-term review for its hydroelectric facilities should not factor into the OEB's decision on whether to approve the nuclear mid-term production review. There are a number of key differences between OPG's nuclear and regulated hydroelectric businesses, including the fact that going forward, the nuclear facilities will operate under a completely different rate-setting framework from the regulated hydroelectric facilities and that OPG's nuclear assets are subject to considerably greater production risk, due in part to the existence of the Water Conditions Variance Account for regulated hydroelectric facilities. For these reasons, OPG submits that the OEB should reject EP's submissions and accept OPG's request for a mid-term production review.

OEB staff submit that OPG's proposed Mid-term Nuclear Production Variance Account (discussed further under Issue 9.8 in Section 10.8) that would facilitate its mid-term production review proposal does not need to be created until the mid-term review application is filed and processed (OEB staff argument, p. 173). OPG respectfully points out that it would be inefficient for the OEB to approve OPG's mid-term production review proposal in this Application and not also approve the corresponding variance account at the same time. For this reason, OPG submits that, if the OEB approves its mid-term production review proposal, it should also approve the corresponding variance account.

The Scope of the Mid-Term Review

Most of the parties that express support for the concept of a mid-term production review also propose changes to its scope.[167] In some cases, the submissions directly oppose each other: for example, OEB staff propose to restrict the review only to changes in Darlington production related to the impact of the DRP, whereas CCC would only allow review of Pickering's production forecast related to the impact of Extended Operations. Certain parties (AMPCO, CME, and CCC) would expand the scope to review the DRP and/or Extended Operation costs.

In OPG's submission, the reduced scope proposed by the parties would make the production forecast review less effective; while proposals to expand the scope to examine DRP and

[167] The PWU supports OPG's proposed mid-term production review scope, submitting that is reasonable and beneficial to both rate payers and OPG (PWU argument, para. 175).

Extended Operations costs are unnecessary, inefficient and, with respect to setting rates on an interim basis, contrary to O. Reg. 53/05. A number of other mechanisms exist as part of the nuclear Custom IR to protect against material changes related to DRP and Extended Operations costs. These include OPG's commitment to bring forward an application should Pickering be shut down earlier than planned, CRVA, Z-factors and, in extreme circumstances off-ramps. Therefore, OPG submits that the OEB should approve the scope of the review as originally proposed by OPG.

OEB staff acknowledge that events may occur during the IR term that could impact the nuclear production forecast. In particular, they note that changes to the timing or approvals for the DRP and PEO could significantly change the nuclear production forecast for the second half of the IR term (OEB staff argument, p. 172). However, OEB staff submit that the mid-term review should be limited to DRP-related production impacts.[168] In OPG's view, it would be inappropriate to consider DRP-related production impacts in isolation from the rest of the Darlington production forecast because of the interrelationship between planned outages and refurbishment outages (see, for example, Ex. J15.10). As a result, OPG submits that if the OEB were to accept OEB staff's proposal to focus the mid-term production review on DRP-related impacts, the scope of the review should broadly consider the impact of DRP-related changes on all of Darlington's operating units and allow for a review of the total impact on Darlington's production.[169]

OEB staff assert that a review of Pickering's production forecast should be excluded from the scope of the mid-term production review given that OPG has confirmed that a new proceeding would be required if Pickering were to shut down earlier than planned (OEB staff argument, pp. 172-173; see Issue 6.5 at Section 7.5 for further discussion). In OPG's respectful submission, the proposal should be rejected because it ignores a number of developments outside of Extended Operations that could also have a material impact on the Pickering production forecast in the second half of the IR term (e.g., changes in FLR assumptions or outage schedules). Including the Pickering production forecast in the scope of the review would be

[168] OEB staff also proposes that OPG be allowed to also bring forward a request to resume accrual accounting for pension and OPEBs for the purpose of determining OPG's revenue requirement (OEB staff argument, p. 173). This is discussed further under Issue 9.2 (Section 10.2).
[169] Similarly, OPG submits that the same argument applies to the impact of PEO on Pickering's production forecast, should the OEB allow Pickering's production forecast to be included in the scope of the mid-term production review.

beneficial to both OPG and customers because of the symmetrical design of OPG's proposal, as discussed above. Regarding CCC's proposal to exclude the review of Darlington's production forecast from the mid-term production review, OPG notes that this would ignore a material source of future production uncertainty, related to DRP outages and post-refurbishment and broader unit performance, and should be rejected by the OEB (CCC, argument, p. 45).

AMPCO, CCC and CME propose expanding the scope of the mid-term proceeding to review Extended Operations after OPG has received a decision on its CNSC licence application and the new LTEP has been issued (AMPCO argument, para. 281; CCC argument, p. 47; CME argument, para. 430). If OPG's proposal on Extended Operations is adopted, these requests are unnecessary as explained in Section 7.5. Furthermore, if CNSC or Government actions materially change OPG's plans for Extended Operations, OPG has agreed to file a new application with the OEB (Tr. Vol. 6, p. 157). Thus, expanding the scope of the review as AMPCO, CCC and CME propose is unnecessary.

AMPCO also expresses concerns regarding DRP in-service date and cost forecasts, and states that the OEB will be better able to determine if the 2020 and 2021 forecasts related to Unit 2 are appropriate at the time of the mid-term review. As such, AMPCO recommends that the OEB establish 2020 and 2021 payment amounts on an interim basis, and finalize these amounts following a review of the status of Unit 2 during the mid-term proceeding (AMPCO argument, paras. 277-280). AMPCO refers to Oshawa PUC Networks' Custom IR plan (EB-2014-0101) as an example of when interim rates were updated with new forecasts during a mid-term review (AMPCO argument, para. 282).

OPG does not believe it is appropriate for the OEB to establish OPG's 2020-2021 payments amounts on an interim basis for the reasons set out in Issue 4.3 (Section 5.3). Moreover, OPG submits that O. Reg. 53/05 precludes the re-opening of the revenue requirement in the mid-term review. Section 6(2)(12)(ii) of the regulation requires the OEB to determine revenue requirements for the nuclear facilities for each year on a five-year basis. 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 authorize the OEB to revisit those approved revenue requirement amounts during the five years and therefore would preclude the OEB from making rates interim as proposed by AMPCO. In addition, because DRP and PEO costs are covered by the CRVA and will be addressed on disposition, reviewing such costs during the mid-term production review would be unnecessary and inefficient. As such, OPG respectfully submits that it would be inappropriate to expand the scope of the mid-term review to include a review of the costs and timing of the refurbishment of Unit 2, as suggested by AMPCO.

CME submits that the mid-term review should include a review of "the progress of the Darlington Nuclear Facility" (CME argument, para. 430). The purpose of the mid-term production review is not to report on the DRP. Rather, OPG has proposed a range of reporting measures on the DRP, as discussed under Issue 10.4 (Section 11.4). In OPG's view, these reporting measures will provide the OEB and customers with sufficient information to understand the progress and scheduling of the DRP, as well as key information on the safety, quality and cost of the program (Ex. L-11.5-6 EP-028).

LPMA submits that if the OEB approves OPG's mid-term production review proposal, then it should also allow for the corresponding change in forecast fuel costs through the Mid-Term Review Production Variance Account, as proposed by OPG (LPMA argument, p. 52). No other parties opposed this aspect of OPG's proposal.

CCC supports OPG's proposal to seek disposal of applicable audited D&V account balances as part of the mid-term review application to avoid the build up of large account balances (CCC argument, p. 47). For the same reason, LPMA and VECC submit instead that OPG should be required to apply for disposition of D&V accounts on an annual basis (LPMA argument, pp. 51-52; VECC argument, para. 11.5.2). OPG submits that its proposal to seek disposal of applicable D&V account balances part way through the IR term (even if the OEB does not approve the mid-term production review) strikes the right balance between regulatory efficiency and avoiding a build-up of large account balances and should be approved by the OEB on that basis.

The Timeframe for a Mid-Term Review

OEB staff recommend that, should the OEB approve a mid-term production review as proposed by OPG, its timeframe should be limited to 2020-2021 and not include the second half of 2019 as OPG proposes (OEB staff argument, p. 173). OPG does not believe the six-month difference in timing between its proposal and OEB staff's proposed timeframe is sufficiently long to create a material increase in risk. As such, so long as OPG is able to seek clearance of the Pension & OPEB Cash Versus Accrual Differential Deferral Account in an application to be filed at the same time as its application for 2018 hydroelectric payment amounts, OPG does not oppose OEB staff's submission.[170]

12.8 Issue 11.6

Oral Hearing: Is OPG's proposal for smoothing nuclear payment amounts consistent with O. Reg. 53/05 and appropriate?

This Application marks the first time that OPG has put an application before the OEB to set payments in accordance with the new payment amount smoothing requirements of O. Reg. 53/05. OPG received not only a large volume, but also a large variety of submissions on payment smoothing.

There is one area on which all parties agree: the implementation of the OEB's decision on payment amount smoothing would be better deliberated after a final revenue requirement has been set by the OEB. OPG proposes that the OEB consider reserving its decision on implementing payment amount smoothing until the payment amounts order process, once the final revenue requirement, final production forecast, D&V account payment riders, and effective date of the new payment amounts approved by the OEB. OPG makes specific submission on the scope of the issue for the payment amounts order process in Section 12.8.5 below.

Notwithstanding the general agreement that the determination of the RSDA deferral balances should be reserved for the payment amounts order process, several parties make broad submissions on the conceptual basis of payment amount smoothing. OPG has addressed these more general submissions below.[171]

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[170] As discussed above under Issue 9.5 (Section 10.5), OPG must begin recovering the balance in the Pension & OPEB Cash to Accrual Differential Deferral Account no later than November 2019.

[171] SEP argues that the OEB should consider as part of rate smoothing OPG's ability to recognize, in accordance with US GAAP, a liability associated with expected involuntary terminations related to the end of Pickering commercial operations "at the time CNSC approves a final out of service date for Pickering." (SEP argument, pp. 21-23). OPG disagrees with SEP on this matter. OPG does not currently expect that it would be in a position to meet the US GAAP recognition criteria referenced by SEP at the time the CNSC issues its decision on OPG's Pickering licence renewal application, which is expected in 2018. SEP has vastly over-simplified the complexities and timing associated with defining the extent of this future liability necessary for recognition. Due to these uncertainties, neither OPG's 2016-2018 Business Plan nor 2017-2019 Business Plan assume that the termination liability would be recognized during the IR term.

12.8.1 Payment Smoothing and the Fair Hydro Plan Act

OEB staff, along with EP, and LPMA make several comments regarding the potential interaction of the payment amount smoothing requirements of O. Reg. 53/05 and the *Ontario Fair Hydro Plan Act, 2017*[172] ("Fair Hydro Act") which was passed by the Legislature on June 1, 2017 (OEB staff argument, pp. 167-177; EP argument, p. 76; LPMA argument, p. 54). OEB staff argue that the rationale for smoothing OPG's payment amounts "would seem to be attenuated" by the Fair Hydro Act, and that the OEB should consider whether the Fair Hydro Plan "alleviates some of the concerns that might otherwise justify a significant smoothing of OPG's WAPA." OEB staff also submit that, since the "Fair Hydro Plan appears to be a form of payment amount smoothing in its own right", the payment amount smoothing proposed in this application "would be unnecessary" (OEB staff argument, pp. 176-177).

As a matter of law, it would be incorrect for the OEB to interpret the payment amount smoothing provisions in O. Reg. 53/05 differently because of the introduction of the Fair Hydro Act. The payment amount smoothing requirements stand on their own. The Fair Hydro Act does not alter O. Reg. 53/05, or otherwise affect the appropriate implementation of its requirements. O. Reg. 53/05 continues to require that the OEB determine the appropriate annual nuclear revenue requirement amounts to defer, via the RSDA, to make OPG's Weighted Average Payment Amounts ("WAPA") more stable during the IR term. OEB staff's proposal could unnecessarily draw the OEB into a web of potential legal conflicts. OPG respectfully submits that the OEB's decision on payment amount smoothing should be based on the legislated requirements of O. Reg. 53/05 and the evidence in this proceeding.

12.8.2 Payment Amount Smoothing and the Capacity Refurbishment Variance Account

OPG received a number of submissions that confuse the legal requirement and intention of both the RSDA and the CRVA. These submissions are addressed in more detail under Issue 9.2 in section 10.2.4.

[172] *Ontario Fair Hydro Plan Act, 2017*, S.O. 2017, c. 16, Sched. 1.

12.8.3 Reductions to Revenue Requirement

OEB staff and SEC argue that some reductions to revenue requirement could mitigate or eliminate the need for payment amount smoothing (OEB staff argument, p. 177; SEC argument, p. 143). OEB staff comment that "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." (OEB staff argument, p. 177).

With respect, this submission is inconsistent with both the OEB's historical practice and a principled approach to regulation. There is no principled basis on which to deny OPG the funding necessary to execute demonstrably prudent work for the sole purpose of mitigating bill impacts. Nor would it be in the interest of consumers to delay execution of prudent work. If it is prudent to do work today, it is reasonable to expect that delaying that work could increase the long-term cost for customers. Just as it is inappropriate to utilize the CRVA to achieve payment amount smoothing objectives, it is even more inappropriate to disallow for the recovery of costs for the sole purpose of smoothing rates.

12.8.4 Deferral and Variance Account Disposition

OEB staff and SEC argue for various D&V account treatments in reference to payment amount smoothing.[173] In so far as these submissions relate to the disposition of 2015 year end balances, OPG has addressed them under Issue 9.5 (Section 10.5).

SEC has proposed that the OEB include a forecast of riders for 2019-2021 period in the payment amount smoothing mechanics which could then be used to reduce any variability in rates resulting from riders (SEC argument, p. 141). This issue is discussed in Section 12.8.5. OPG submits that SEC's proposal to forecast riders now would unnecessarily complicate D&V account dispositions in future applications and could also limit the OEB's ability to respond to the specific circumstances in those proceedings.

As detailed in Issue 9.5 (Section 10.5), OPG will be bringing forward an application to transition back to accrual accounting before 2021 and will include the disposition of balances in the

[173] LPMA, QMA, VECC, CCC, EP, and GEC all support OEB staff's submissions

Pension & OPEB Cash Versus Accrual Differential Deferral Account in that application. OPG proposes to clear the Pension and OPEB Cash Versus Accrual Differential Deferral Account in an application to be filed with the application for 2018 hydroelectric payment amounts. The remaining D&V accounts would be cleared as part of the mid-term review. In addition, the disposition of the two Pension & OPEB Cost Variance Accounts was previously determined as part of the EB-2012-0002 and EB-2014-0370 proceedings (Ex. H1-1-1, p. 1) and spans over the 2017-2021 IR term.

12.8.5 Mechanics of Payment Amount Smoothing

Intervenors proposed a range of approaches to the specific WAPA rates that the OEB should prefer and the deferral amounts it should approve. Some intervenors propose that OPG should defer as little as possible over the IR term, where others recommend a larger deferral. Some parties supported a consistent change in the WAPA, where others proposed zero deferral in most years, but with “rounding the edges” if the payment amounts spike substantially in one or more years.

OPG maintains that its proposal, as set out in Ex. N3-1-1 is objective, reasonable, and appropriate. Since all parties agree that the decision on payment amount smoothing should be reserved for the payments amount determination process, OPG will reserve its comments on the payment amount smoothing mechanics proposals by intervenors until that time. Assuming the OEB endorses this approach, this will allow all parties to make their submissions based on the final revenue requirement, final production forecast, D&V account payment amount riders, and effective date of the new payment amounts approved by the OEB.

OPG submits that it would be helpful if the OEB were to include in its decision whatever principles it determines to be appropriate and identify the parameters it expects parties to make submissions on, such that a more focused range of payment amount smoothing alternatives can be practically and efficiently considered at the payment amounts order stage. For its part, OPG suggests these parameters could include:

- The methodology to determine the deferral amounts each year (OPG’s proposed deferrals are provided in Ex. N3-1-1, Table 1 based on the proposed revenue requirement);
- The method by which rates will change in each year (OPG proposes to increase the WAPA by constant 2.5% each year from 2017-2021);

- An affirmation of any previously identified principles or considerations that the OEB deems to be appropriate for use in the consideration of payment amount smoothing (OPG's considerations are detailed in Ex. N3-1-1, p. 5); and
- The dismissal of any payment amount smoothing proposals put forward through summary arguments that the OEB determines to be inconsistent with O. Reg. 53/05.

OPG submits the SEC's payment amount smoothing proposal on how to treat riders in the 2019-2021 period is inconsistent with O. Reg. 53/05 (SEC argument paras. 10.11.23-10.11.32). SEC correctly points out that under O. Reg. 53/05 the OEB is directed to make a determination, and the sole direction is that the OEB must make that determination "with a view to making more stable the year-over-year changes in the OPG weighted average payment amount over each calculation period."

Based on this SEC incorrectly believes that the OEB must smooth the individual elements of the WAPA. However, SEC is placing too fine a point on its interpretation. The OEB's obligation extends to the WAPA in total. The definition of the WAPA is provided to clarify the object of the smoothing exercise. However, the discretion as to how the OEB chooses to make more stable the WAPA is wholly with the OEB and it is not restricted to any one mechanistic approach or the level of precision as proposed by SEC. As such, the OEB is not required to impose a formula on the smoothing exercise.

Ontario Reg. 53/05 also does not preclude the OEB from approving new riders in the future after the smoothing exercise is completed. As has the OEB done previously, it can approve both a revenue requirement and the disposition of D&V accounts giving rise to payment amounts and riders, and then, in a subsequent proceeding approve further disposition of accounts with amended riders. There is nothing in the wording of O. Reg. 53/05 that alters or restricts the OEB's jurisdiction in this regard. The OEB can approve new riders for the disposition of accounts subsequent to the completion of the rate smoothing exercise.

12.9 General

12.10 Issue 11.7

Primary: Is OPG's proposed off-ramp appropriate?

OEB staff, LPMA, and VECC have all made submissions in support of OPG's off-ramp (OEB staff argument, p. 168; LPMA argument, p. 55; VECC argument, para. 5). OPG received no submissions in opposition of their proposed off-ramp. OPG submits that the OEB should find OPG's off-ramp proposal to be appropriate on the basis of its written evidence.

13.0 IMPLEMENTATION

13.1 Issue 12.1

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

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

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

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

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

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

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

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

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

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

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

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

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

> (a) the revenue requirement amount approved by the Board that, but for subparagraph 12 i of subsection 6 (2) of this Regulation, would have been used in connection with determining the payments to be made under section 78.1 of the Act each year during the deferral period in respect of the nuclear facilities; and
>
> (b) the portion of the revenue requirement amount referred to in clause (a) that is used in connection with determining the payments made under section 78.1 of the Act, after determining, under subparagraph 12 i of subsection 6 (2) of this Regulation, the amount of the revenue requirement to be deferred for that year in respect of the nuclear facilities. O. Reg. 353/15, s. 2. (emphasis added).

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

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

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

13.1.2 A January 1, 2017 Effective Date is Appropriate

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

APPENDIX A

Ministry of Energy

Office of the Minister

4th Floor, Hearst Block
900 Bay Street
Toronto ON M7A 2E1
Tel.: 416-327-6758
Fax: 416-327-6754

Ministère de l'Énergie

Bureau du ministre

4e étage, édifice Hearst
900, rue Bay
Toronto ON M7A 2E1
Tél. : 416 327-6758
Téléc. : 416 327-6754

Ontario

MAY 30 2017

Mr. Bernard Lord
Chair
Ontario Power Generation
1900–700 University Avenue
Toronto ON M5G 1X6

Dear Mr. Lord:

Thank you for your submission of Ontario Power Generation's (OPG) 2017-2019 Business Plan ("the Plan"). We have reviewed the Plan and find it to be consistent with our government's expectations.

I support the operational and financial targets set by OPG in its business plan. We recognize the substantial cost reductions that OPG has recently achieved and expect OPG to work closely with the Province to fully realize the additional efficiencies incorporated in the Plan in a manner that is consistent with the continued safe and environmentally responsible operation of OPG's facilities.

We commend OPG on its successful start to the Darlington Refurbishment Project, a key objective of Ontario's 2013 Long-Term Energy Plan (2013 LTEP). As a priority project for the government, I expect that OPG will continue to focus on delivering the project as per the schedule and budget contained in the Release Quality Estimate approved by the OPG Board and by the government. I also expect OPG to continue to minimize project risks consistent with the nuclear refurbishment principles set out in the 2013 LTEP, and seek concurrence prior to commencing refurbishment of Unit 3 before the end of 2017.

We continue to support the planned operation of Pickering units up to 2024, subject to OPG obtaining necessary regulatory approvals, as the station's output will provide reliable, cost-effective and emission-free electricity supply during the Darlington and initial Bruce refurbishments. I expect OPG to keep the ministry apprised throughout the regulatory processes and as we proceed to update the Long-Term Energy Plan.

I understand that the recently approved Ontario Nuclear Funds Agreement (ONFA) Reference Plan has resulted in a reduction of the estimated liabilities for future decommissioning and long-term management of waste from Ontario's nuclear fleet. With many decades of nuclear generation in the province's future, we expect OPG to continue managing its decommissioning and waste management obligations and related segregated funds in a prudent manner. I recognize that the ONFA Reference Plan is based on OPG's proposed siting of a Deep Geologic Repository (DGR) for low and intermediate level waste at the Bruce site. OPG's DGR is a key component of Ontario's plans to ensure that nuclear remains the backbone of our electricity system for years to come.

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I appreciate the efforts of OPG staff, management and the Board of Directors to date as we worked to develop a plan to refinance the Global Adjustment (GA). Refinancing the GA would provide significant and immediate rate relief by spreading the cost of electricity investments over the expected lifecycle of the infrastructure that has been built. OPG will be instrumental to the success of this initiative and we plan to introduce legislation that would, if passed, enable OPG to work with the Independent Electricity System Operator to implement this plan. I also expect to make the necessary changes to OPG's articles of amalgamation to provide the financing flexibility to implement the refinancing of the GA to meet the Province's price objectives announced on March 2, 2017.

I expect OPG to continue to keep the government informed with regard to the company's key ongoing and emerging initiatives and progress in achieving its financial and operational performance commitments. As OPG's performance directly impacts Ontario's fiscal plan, we note the importance of achieving or exceeding OPG's financial performance commitments.

Consistent with Section 7 of the Memorandum of Agreement, in advance of commencing discussions for the renewal of its collective agreements with its unions, I expect that OPG shall seek advice from the ministry on provincial policy direction and relevant fiscal considerations affecting labour negotiations.

This letter constitutes our concurrence with OPG's Board-approved 2017-2019 Business Plan as provided for under the Memorandum of Agreement between OPG and the Shareholder dated July 17, 2015.

This letter also confirms the approval of special status for OPG to approve international travel, under Section 5.3 of the Management Board of Cabinet's Travel, Meal and Hospitality Expenses Directive. OPG shall submit semi-annual reports on international travel to the Ministry of Energy, as described in the submission received from OPG's President and CEO, dated January 24, 2017.

Sincerely,

Glenn Thibeault
Minister

c: Jeff Lyash, President and Chief Executive Officer, Ontario Power Generation
Serge Imbrogno, Deputy Minister, Ministry of Energy
Scott Thompson, Deputy Minister, Ministry of Finance
Andrew Teliszewsky, Chief of Staff to the Minister of Energy
Ali Ghiassi, Chief of Staff to the Minister of Finance