EB-2010-0008

OEB Application

for

Payment Amounts for OPG’s Prescribed Facilities

Reply Argument

Ontario Power Generation Inc.

December 21, 2010

This page has been left blank intentionally.

TABLE OF CONTENTS

1.0 INTRODUCTION

This reply responds to numerous points raised in the submissions by Board staff and intervenors. Before addressing the specifics of the issues under dispute, OPG wishes to provide an overall context for this Application and comment on some of the approaches that other parties have taken in the hearing and in argument.

In those instances where intervenors have either said nothing or taken no issue with the relief sought by OPG, there is nothing to respond to and OPG submits that its requests should be granted as filed. OPG relies on all of its evidence and the Argument-in-Chief ("AIC") already filed to support the relief requested, and does not repeat those arguments here.

Cost Containment and Operational Excellence Provide the Overarching Context for this Application, but Limits Exist

In the last payment amounts application, the OEB made clear its belief that OPG should do a better job at controlling its costs and improving its performance. Internal direction from OPG's Board of Directors and senior management was to the same effect (Ex. A1-T3-S1, pp. 4-6). External economic factors have only intensified the need for OPG to drive efficiencies through its business planning efforts.

There should be no doubt, contrary to some intervenor claims, that OPG has gotten the message. After safety, operational excellence and cost control are its top priorities. OPG submits that starting with its decision to defer its Application for a year and continuing through to its proposal to extend the recovery of its Tax Loss Variance Account balance, the company's decisions demonstrate its awareness of customer impacts. The application contains numerous examples where OPG has taken steps to reduce costs (Ex. A1-T3-S1, pp. 4-5). At the same time, however, OPG appreciates that there are limits to its ability to cut costs while continuing to produce electricity in a safe and reliable manner over the long-term.

Like all businesses, OPG operates within constraints. Labour, by far the largest portion of the company's costs, is heavily unionized. OPG is obligated to respect existing collective agreements and bargain in good faith to achieve new ones. The age, size and design of its regulated nuclear plants impact their output and cost. These facts are not offered as excuses or in an attempt to relieve the company's management of its obligation to continuously improve performance. Rather, they are offered as examples of real world factors that management, unlike intervenors, cannot ignore. Proposals that urge the OEB to cut costs that management cannot cut or ignore obligations that management must meet are inconsistent with the OEB's obligation to establish just and reasonable rates and should be rejected.

The Role of the OEB and the Roles of OPG's Shareholder, Board of Directors and Management

OPG has the greatest respect for the OEB as it discharges the difficult task of setting just and reasonable payment amounts and decides the numerous matters necessary to accomplish this. As broad as the scope necessary to discharge this task is, however, it is not unlimited. The OEB should decline the numerous invitations extended by intervenors to assume roles and responsibilities properly discharged by OPG's shareholder, Board of Directors, and management.

The OEB has declined similar invitations in the past. In the previous payment amounts proceeding, intervenors urged the OEB to insert itself in the role of OPG's Board of Directors and, ultimately, its shareholder, and decide on the long-term viability of Pickering A. The OEB rejected this invitation stating that its role is to develop payment amounts and that the matter of Pickering A's viability ultimately was a decision for OPG's shareholder (Decision with Reasons, EB-2007-0905, p. 28).

Just as the applicable statutes do not assign the OEB the role of deciding on Pickering A's viability, they do not assign it the role of deciding whether Darlington should be refurbished. That is a decision that has been made by OPG's Board of directors and endorsed by the Minister of Energy on behalf of the Government of Ontario. If the OEB determines that OPG has adequately supported the revenue requirement changes that it proposes as a consequence of the Darlington Refurbishment project, it should accept them. OPG will take from this that the OEB finds the approach to proceeding with the project and test period spending described fully in OPG's evidence to be reasonable. It will not take the OEB's decision as approval of spending for later phases of the project in future periods. Nor will OPG believe that it is immune from a subsequent review of the prudence with which it undertook project expenditures.

In a similar vein, for matters large (the determination of whether OPG must review changes in pension costs with its shareholder) and small (demonstrating compliance with the Minister of Energy's request to return HST savings to consumers) parties have invited the OEB to engage in micro-management and substitute its judgement for that of OPG's management (Board staff argument, pp. 77, 99). Again, these are invitations that the OEB should decline. The responsibility for running OPG rests with its publicly appointed Board of Directors and its management.

The Need to Decide Matters Based on Evidence

OPG recognizes its obligation to produce the evidence necessary to meet its burden of proof to establish that its forecast costs are reasonable and prudently incurred (Section 78.1(6) of the *Ontario Energy Board Act*). As the applicant, however, OPG enjoys a presumption that the evidence that it has presented demonstrates that its costs are reasonable unless and until their reasonableness is challenged by parties to a proceeding.

For fundamental reasons of procedural fairness, parties must base their submissions on evidence, filed by them, developed through cross-examination or produced by the applicant in response to interrogatories, Technical Conference questions or undertakings. This is necessary to allow an applicant a chance to respond by testing any contrary evidence submitted or introducing additional evidence to demonstrate the reasonableness of its requests.

The OEB released *A Report with Respect to Decision-Making Processes at the OEB* dated September 2006 (the "*Board Process Report*"), that addressed the need to rely on evidence. The Board Process Report concluded as follows:

> Thus, in the non-prosecutorial context, the courts' emphasis has been on ensuring <u>that parties have the right to know and answer the case they have to meet</u> (emphasis added). This involves a requirement that a decision maker not base his or her decision on facts which are not on the record and parties have the opportunity to respond to legal and

> policy arguments that are considered by the decision maker. (Board Process Report, page 26).

Unfortunately, in this proceeding, the submissions of Board staff, and those of other parties, repeatedly urge the OEB to decide matters on the basis of information that was never introduced during the evidentiary portion of the proceeding and, sometimes, based on no evidence at all. Material that was not sponsored by any party or even put to OPG's witnesses appears for the first time in argument. Calculations which never surfaced in the hearing and are frequently wrong are offered to justify hundreds of millions in disallowances. Below are a few examples.

Board staff asks that OPG's decision to begin capitalizing Darlington Refurbishment costs be rejected based solely on its interpretation of an excerpt from the Canadian Institute of Charted Accountants Handbook (Board staff argument, pp. 33-35). This interpretation was not sponsored by any expert witness, entered into evidence or tested during cross-examination. It was not even put to OPG's witnesses, five of whom are Chartered Accountants, for review and response. Instead, it appears for the very first time in Board staff's argument. As shown below, the section cited by Board staff applies to intangible property, which Darlington certainly is not and, in any event, it has been misinterpreted by Board staff. That OPG is able to easily demonstrate that Board staff's argument is wrong, however, does not change the fact that staff's actions are procedurally improper and fundamentally unfair. If Board staff wanted to rely on this section in argument, at the very least, they were obligated to put it before OPG's witnesses during the hearing.[1]

In a similar manner, SEC devotes 20 pages of argument presenting its views on the way to calculate the balance in the Tax Loss Variance Account and OPG's regulatory tax expense (SEC argument, pp. 53-74). At the heart of this submission is a "calculation" of OPG's available tax deductions that lacks any evidentiary basis; it was never put on the record or discussed with OPG's witnesses. That this "calculation" is wrong and completely inconsistent with applicable tax and regulatory principles is established below

[1] See Browne *v. Dunn* which establishes a rule of fairness that prevents the "ambush" of a witness by not giving the witness an opportunity to state his or her position with respect to later evidence that contradicts him or her on an essential matter. This is a long standing and widely applied rule accepted by both courts and administrative tribunals. (6R.67 (1893), House of Lords)

(Section 11.1, Tax Loss Variance Account). The point here is that SEC believes it appropriate to recommend over a billion dollars in reductions to OPG's regulatory taxable income based on material that was never introduced in evidence. The OEB should firmly reject this approach.

A prominent example of a request that the OEB make a significant decision, potentially involving hundreds of millions of dollars, without any evidence at all is the request to arbitrarily assume that the appropriate wage level for OPG's unionized employees is set by the 50th percentile of the Towers Perrin comparator group (Board staff argument p.66; SEC argument paras. 6.8.8 to 6.8.11; CME argument paras. 161-165; CCC argument, paras. 129 to 131; VECC argument, para. 50). There is not a shred of evidence that would support a finding that this is the reasonable level of compensation for the work that OPG's unionized employees perform. Instead, parties simply assert this claim in their arguments, as if it were self evident, and ask the OEB to reduce wages accordingly. To reduce the wages of thousands of OPG employees based on an assertion that lacks any evidentiary support would be both wrong and unfair.

One-sided Analyses and the Public Interest

OPG is particularly concerned about Board staff's arguments which present one-sided analyses and simply ignore evidence that undercuts staff's position. This approach to argument is inconsistent with the role of Board staff to promote the public interest. The *Board Process Report* referenced above concluded the following:

> The staff role being proposed here is the identification and evaluation of options for consideration by the panel. This involves demonstrating leadership in the hearing room, but not for the purpose of supporting or opposing a party's position. Staff's only driver is the public interest, and they remain neutral as between parties. Their analysis may lead them to see one argument or option as having greater public interest value than another. This is not the same as taking an adversarial position against a party. There are clearly limitations on how adversarial staff may be in pursuing its positions. The courts have noted that tribunal staff where leading evidence and making submissions, represents the public interest, and therefore have a different responsibility than a private party.
>
> Provided that staff are pursuing a public and non-partisan interest, and provided that <u>staff positions are put on the record or otherwise</u>

> disclosed to the parties (emphasis added), staff involvement both in the hearing and in assisting the Board following a hearing is consistent with the duty of fairness owed to the parties in the circumstances of a Board hearing (Board Process Report, p. 22).

Throughout its argument, Board staff cites examples where OPG is alleged to have spent less in the prior test period than was authorized by the OEB. Some of these examples are wrong (see the discussion of prior period nuclear staff levels in section 5.3, Employment Levels and Reporting). Others deliberately present only half the story (see the discussion of prior period nuclear capital spending and associated depreciation in section 4.6, Projects). Never once in its entire argument does Board staff acknowledge that there were also areas where prior test period spending was above forecast (e.g. nuclear outage OM&A).

This type of "cherry-picking" is inconsistent with the public interest role of Board staff and the admonishment against taking purely adversarial positions contained in the quote above. While a full review of prior test period spending can be informative in terms of trends and the company's actual requirements, a one-sided review, focusing only on areas of alleged under-spending, adds nothing to the determination of appropriate test period forecasts.

If Board staff's presentation of OPG's prior period spending were accurate, one would expect to see massive over-earning in both 2008 and 2009. That is not what happened. OPG earned significantly below its authorized Return on Equity in both 2008 and 2009 (see Ex. C1-T1-S1, Tables 4 and 5 and Tr. Vol. 11, pp. 108-114).

OPG also questions exactly what implications Board staff would have the OEB draw from these one-sided presentations. The OEB approves a revenue requirement. While this overall revenue requirement is developed from forecasts of specific spending categories, applicants are in no way limited to spending only the amounts approved in each category. As conditions change and new priorities emerge, actual test period spending will necessarily diverge from forecast to address these changes and meet new priorities. Management's responsibility is not to slavishly spend to the budgets forecast in the last proceeding. Rather, it is to continually assess the needs of the business and the conditions that it faces and adjust spending accordingly. This will always result in deviations between forecast and actual spending in specific categories with some being below and others above forecast.

Response to Previous Board Direction

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

With the exception of Energy Probe, no party takes issue with OPG's response to previous direction. Energy Probe argues that OPG was obligated to respond to the disallowance of certain nuclear advertising costs in the last hearing and to Energy Probe's proposals to modify the Hydroelectric Incentive Mechanism, which the OEB rejected (EP argument, pp. 5-8). OPG disagrees.

The OEB's Filing Guidelines for Ontario Power Generation Inc. (page 6) set out a table specifying the previous directions to which OPG must respond. The issue of nuclear advertising does not appear in this table. Moreover, it would make no sense to require OPG to submit evidence on areas, like nuclear advertising, in which it is not requesting funding just because those areas had been discussed in a previous application.

This issue of the Hydroelectric Incentive does appear in the table in the following form: "Present a review of the hydroelectric incentive mechanism which examines the impact of the incentive structure on OPG's operating decisions." OPG responded to this issue, as Energy Probe acknowledges, but did not address the specific matter that Energy Probe had raised in the last proceeding (EP argument, p. 7). As Energy Probe further acknowledges, it could have asked interrogatories or Technical Conference questions on this matter, but did not.

OPG submits that having met the requirements of the OEB's Filing Guidelines, it has broad discretion to decide what evidence is required to support its case. If other parties believe that more is required on a particular issue, it is for them to seek additional information. It makes little sense to further burden applicants by requiring them to review each issue that was discussed in the previous case and decide whether it is still outstanding in the mind of the party that originally raised it.

2.0 BUSINESS PLANNING AND CUSTOMER IMPACTS

Issue 1.2 - Are OPG's economic and business planning assumptions for 2011-2012 an appropriate basis on which to set payment amounts?

Issue 1.3 - Is the overall increase in 2011 and 2012 revenue requirement reasonable given the overall bill impact on consumers?

2.1 INTRODUCTION

A handful of intervenors commented on these issues with CCC and CME taking the lead. They argue that the OEB should disallow some of OPG's claimed relief on the untenable basis that aspects of the electricity bill over which OPG has no control are rising. With respect, intervenor arguments overstate the jurisdiction of the OEB, fail to identify any meaningful weakness in OPG's planning process, and ultimately devolve into a complaint relating to the legislative and policy choices made by the Province.

2.2 RIGHT TO RECOVERY OF PRUDENTLY INCURRED COSTS

Relying on the OEB's objectives and the Ontario Court of Appeal's decision in the Toronto Hydro case, CCC argues that the OEB can reduce forecast spending, not because it is imprudent, but "out of a concern for [its] impact on electricity prices" (CCC argument, para. 19). This argument runs contrary to the well-established principle that a utility is entitled to recover all of its prudently incurred costs.

Section 78.1 of the *OEB Act* adopts the "just and reasonable" standard for the OEB's determination of the payment amounts that the IESO must make to OPG for the output of the prescribed facilities. This is the same standard prescribed in the Act for gas and electricity distribution companies. Comparable legislation also exists in other provinces and in the U.S.

Mr. Justice Lamont described just and reasonable rates as "rates, which, under the circumstances, would be fair to the consumer on the one hand, and which, on the other hand, would secure to the company a fair return for the capital invested."[2]

[2] Northwestern Utilities Ltd. v. Edmonton (City), [1929] S.C.R. 186 at 192-93 (Lamont J.); see also British Columbia Electric Railway Co. Ltd. v. British Columbia (Utilities Commission), [1960] S.C.R. 837 at 855.

These two components of the just and reasonable standard — that rates be fair to the consumer and yield fair compensation to the utility and its owner — are also embodied in the OEB's objectives regarding the regulation of electricity: 1) the protection of consumer interests; and 2) facilitating a financially viable electricity industry. CCC and CME's arguments ignore any sense that the payment established by the OEB must also be fair to OPG.

Fair compensation to the utility is comprised of two legal entitlements: 1) the right to recover all prudently incurred costs (where prudence is evaluated without the benefit of hindsight but on the basis of information that was reasonably available to management at the time the relevant decisions were made); and 2) the right to a fair return on invested capital. The fair return on capital is dealt with in OPG's AIC (page 64), and further below in Section 8.0, Cost of Capital.

The principle of entitlement to recovery of prudently incurred costs has been widely accepted in Canada and the U.S.[3]

Expenditures are deemed to be prudent in the absence of reasonable grounds to suggest the contrary. Only costs that are found to be dishonestly incurred, or which are negligent or wasteful losses, may be excluded from the legitimate operating costs of the utility in determining the rates that may be charged. The examination of prudence must be based on the particular circumstances at the time the decision which led to incurring those costs was made. That is so even if, in hindsight, it is apparent that the decision was wrong.[4]

The OEB correctly defined the prudence standard at paragraph 3.12.2 of its decision in RP-2001-0032 as follows:

---

[3] State of Missouri ex. rel. Southwestern Bell Telephone Co. v. Public Service Commission of Missouri, 262 U.S. 276 (1923) at p. 289; British Columbia Electric Railway Co. Ltd. v. British Columbia (Utilities Commission), [1960] S.C.R. 837 [British Columbia Electric Railway Co. Ltd.] at p. 854; TransCanada Pipelines Ltd. v. National Energy Board et al. (2004), 319 N.R. 172 (F.C.A) at paras. 35-36; West Ohio Gas Co. v. Public Utilities Commission of Ohio (No. 1), 294 U.S. 63 (1935) at p. 68; Re Union Gas Limited (September 20, 2002), Ontario Energy Board Decision RP-2001-0029, online: OEB <http://www.oeb.gov.on.ca/documents/cases/RP-2001-0029/decision_200902.pdf>, at pp. 20-24; Re Enbridge Gas Distribution Inc. (December 13, 2002), Ontario Energy Board Decision RP-2001-0032, online: OEB <http://www.oeb.gov.on.ca/documents/cases/RP-2001-0032/decision_171202.pdf>, at pp. 62-63; Enbridge Gas Distribution Inc. v. Ontario Energy Board (2005), 75 O.R. (3d) 72 (Div. Ct.); rev'd on other grounds, (2006), 41 Admin L.R. (4th) 69

[4] Violet v. FERC, 800 F. 2d 280 at p. 282 (1st Cir. 1986), cited with approval in Enbridge v. Ontario Energy Board (2005), 75 O.R. (3d) 72 (Div. Ct.) at para. 9

1. Decisions made by the utility's management should generally be presumed to be prudent unless challenged on reasonable grounds.
2. To be prudent, a decision must have been reasonable under the circumstances that were known or ought to have been known to the utility at the time the decision was made.
3. Hindsight should not be used in determining prudence, although consideration of the outcome of the decision may legitimately be used to overcome the presumption of prudence.
4. Prudence must be determined in a retrospective factual inquiry, in that the evidence must be concerned with the time the decision was made and must be based on facts about the elements that could or did enter into the decision at the time.

This approach has been explicitly affirmed by the Ontario Divisional Court and the Court of Appeal in *Enbridge Gas Distribution Inc. v. Ontario Energy Board*.[5]

The OEB considered the relationship between the objective of protecting the interests of customers with respect to prices and the requirement to set just and reasonable rates in its Cost of Capital Report.[6] In that Report, the OEB reviewed the application and content of the "fair return standard" for a utility's invested capital. Of course, the determination of a utility's return is but one specific example of the costs making up its overall revenue requirement. In the Report, the OEB relies upon the decision of the Federal Court of Appeal in *TransCanada PipeLines Limited v. National Energy Board et al.* [2004] F.C.A 149 which provided that:

> … even though the cost of capital may be more difficult to estimate than some other costs, it is a real cost that the utility must be able to recover through its revenues. If the… [OEB] does not permit the utility to recover its cost of capital, the utility will be unable to raise new capital or engage in refinancing as it will be unable to offer investors the same rate of return as other investments of similar risk. As well, existing shareholders will insist that retained earnings not be reinvested in the utility.[7]

---

[5] See footnotes 2 and 3 *supra*.
[6] EB-2009-0084
7 TransCanada PipeLines Limited v. National Energy Board, supra, 12

The OEB specifically considered how the obligation to ensure that the utility recovers these costs should be balanced against the interests of consumers, concluding that any resulting rate increase is relevant only to whether the costs, *while recoverable*, should be deferred:

> Second, the OEB agrees with the National Energy Board which stated that "[i]t does not mean that in determining the cost of capital that investor and consumer interests are balanced." Further, the OEB notes that the Federal Court of Appeal was clear that the overall ROE must be determined solely on the basis of a company's cost of equity capital and that <u>"the impact of any resulting toll increase is an irrelevant consideration in that determination.</u> This does not mean however, that any resulting increase in tolls cannot be considered by a tribunal in determining the way in which a utility should recover its costs." The Federal Court of Appeal also stated that:
>
> > It may be that an increase is so significant that it would lead to "rate shock" if implemented all at once and therefore should be phased in over time. It is quite proper for the OEB to take such considerations into account, provided that there is, over a reasonable period of time, no economic loss to the utility in the process. In other words, the phased in tolls would have to compensate the utility for deferring the recovery of its cost of capital.[8] (emphasis added)

A utility is entitled to the recovery of its cost of capital because it is one of the prudently incurred costs of providing utility service. The utility cannot be denied the ability to recover these costs simply by virtue of the impact that those costs may have on customers. In short, prudent costs do not become imprudent because of an undesirable rate impact.

Rate impact mitigation may be appropriate through the use of deferral accounts, but they address the manner of recovery of costs, not the fact that the costs must be recovered.[9] As described above, once the OEB has determined that those costs are prudently incurred; it must permit the utility the opportunity to ultimately recover those costs.

The OEB similarly considered and rejected intervenor arguments along the present lines in Hydro One's 2009 and 2010 rates application (EB-2008-0272). At the height of the

---

[8] Cost of Capital Report, *supra*, p. 19
[9] *Natural Resource Gas Ltd. v. Ontario Energy Board*, 2006 CanLII 24440 (ON C.A.) at para. 28; *ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board),* 2006 SCC 4, [2006] 1 S.C.R. 140 at para. 63-65.

recent economic downturn, the OEB held that it would be inappropriate to, "arbitrarily reduce spending in direct response to the economic downturn" (EB-2008-0272, page 4).

Finally, intervenor reliance on the Court of Appeal's decision in the Toronto Hydro is misplaced. If anything, a careful review of the case confirms OPG's position. In that case, the OEB's decision, ultimately upheld by the Court, was driven by a concern that the utility had been under-investing in its physical plant for several years, thereby placing system reliability at risk. In short, unlike the present case, the prudence of the utility's actions was directly engaged (2010 ONCA 284, para. 55).

2.3 OPG'S BUSINESS PLANNING PROCESS

CME and CCC heavily criticize OPG's business planning process. Their arguments however have nothing to do with OPG. They are based entirely on the untenable assertion that OPG was under an obligation in its planning to have regard for costs over which it has no control. As CME says:

> OPG's planning process is deficient because it fails to take account, in any meaningful way, the total electricity price increases consumers are currently experiencing and will be facing over the five-year planning horizon OPG uses. OPG does not consider any electricity price changes that are outside of its control. (CME argument, para 60)

In effect, CME and CCC claim that it was incumbent on OPG to "take one for the team" by artificially reducing the necessary level of spending, failing which, the OEB should step in. As detailed above, there is absolutely no proper basis for their position and it would be legally wrong to accede to it.

As the PWU correctly notes in its argument, it is particularly inappropriate for the OEB to undertake the specific exercise which is urged upon it by CCC and CME. Many of the costs which are said to be affecting the total customer bill are costs over which the OEB has no jurisdiction e.g., electricity commodity costs, the cost of the "global adjustment" and the impact of HST on electricity bills. To deny the OPG recovery of otherwise prudently incurred costs by virtue of the impact of these factors have on customer bills effectively would result in the OEB using OPG's payment amounts as a vehicle for regulating the cost of unregulated electricity commodity sources or the HST.

Further, for those costs over which the OEB does have regulatory authority, these are beyond OPG's control and are costs which the OEB has already determined in other proceedings are just and reasonable. It would be manifestly unfair for the OEB to deny cost recovery to OPG based upon the impact of the recovery of other applicants' costs previously approved by the OEB.

CME makes two additional and related arguments in support of its business planning criticisms. First, it (along with CCC) argues that OPG failed to respond appropriately to Minister Duguid's letter dated May 5, 2010 (CME argument, pp. 19-22; CCC argument paras. pp. 35-39). Second, CME alleges that OPG has made "material misstatements of costs" (CME argument, pp. 14-15). Neither argument withstands scrutiny.

As explained at length in the hearing, well before receiving Minister Duguid's letter, OPG senior management decided to delay filing of the application in order to consider whether there were aspects of that application that could be reasonably be adjusted (Tr. Vol. 15, p. 15).

OPG ultimately determined to delay the implementation of rates to March 1, 2011 and extend the period of recovery for the Tax Loss Variance Account. OPG, admittedly, did not change its work programs or budgets in its 2010-2014 Business Plan. As the witnesses testified, this was not necessary given the care OPG took in containing costs over which it has control during business planning (Ex. F2-T1-S1, Attachment 1, p. 16; Ex. A2-T2-S1, Attachment 1, p. 10; Tr. Vol. 15, pp. 14-17).

For its part, SEC engages in a "fun with numbers" exercise in an effort to artificially inflate the payment amounts increase being sought by OPG (SEC argument, paras. 1.3.14 - 1.3.20). The numbers put forward by SEC are meaningless and do not fairly portray OPG's application.

As described in its AIC, OPG is seeking an overall increase of 3.9 per cent on payment amounts (AIC, p. 2). It is important to note that current payment amounts will have been in effect for almost three years by the time OPG's proposed payments are changed on March 1, 2011 (Tr. Vol. 15, page 10). Even when considering the impact of variance and deferral accounts, which largely address under-recoveries embedded in the previous payment amounts, the increase that OPG is seeking is approximately 6.2 per cent (Ex. A1-T3-S1, page 3). This is equivalent to about two per cent a year over the past three years. In terms of consumer impact, this increase would result in an estimated increase of $1.86 per month on the bill of a typical residential consumer (Ex. I1-T1-S2).

Unlike the apples to apples comparison done by OPG, SEC's argument (para. 1.3.1 - 1.3.20) is based on an analysis of numbers which even SEC admits are "not…directly comparable." It understates current payment amounts by including the error identified in EB-2009-0038 and overstates future payments by including post test period amounts to arrive at an alleged 13 per cent rate increase. Of course, given that both the starting and ending points are wrong, the result is inaccurate and should be disregarded by the OEB.

3.0 HYDROELECTRIC

3.1 BUSINESS PLANNING AND BENCHMARKING

Issue 6.2 - Is the benchmarking methodology reasonable? Are the benchmarking results and targets flowing from those results for OPG's hydroelectric facilities reasonable?

No party objected to OPG's benchmarking methodology, results or targets flowing from those results for the regulated hydroelectric facilities, and as such, and for all the reasons set out in its evidence and AIC, the benchmarking for the regulated hydroelectric facilities should be accepted by the OEB as filed.

3.2 OM&A

Issue 6.1 - Is the test period operations, maintenance and administration budget for the regulated hydroelectric facilities appropriate?

No party objected to OPG's test period OM&A budget for the regulated hydroelectric facilities, with the exception of compensation issues (considered in Section 5.2) and the OM&A associated with the St. Lawrence Power Development Visitor Centre (considered in Section 3.4, Hydroelectric Capital Projects). As such, and for the reasons set out in its evidence and AIC, OPG submits that the OM&A budget for the regulated hydroelectric facilities should be accepted by the OEB as filed, subject to its findings on compensation and project OM&A for the Visitor Centre.

3.3 OTHER REVENUES

Issue 7.1 - Are the proposed test period regulated hydroelectric business revenues from ancillary services, segregated mode of operation and water transactions appropriate?

Consistent with the treatment approved by the OEB in EB-2007-0905, OPG proposed that revenues (less costs) from the following hydroelectric ancillary services be applied as an offset to the hydroelectric revenue requirement:

- Black start capability
- Operating reserve
- Reactive support/voltage control service, and
- Automatic generation control ("AGC").

Provision of the above services is integral to the operation of OPG's prescribed assets. A forecast of these other revenues for the test period is included in the calculation of the revenue requirement for the regulated hydroelectric facilities. Differences between this forecast and actual revenues are recorded in the Ancillary Service Net Revenue Variance Account - Hydroelectric Sub Account, as approved by the OEB in the last payments amounts case (Ex. G1-T1-S1, pp. 1-2). Since no evidence was advanced or argument made to modify this approach, OPG requests the OEB approve the methodology and the amounts for the hydroelectric ancillary services.

Similarly, as no party advanced evidence or made argument on Congestion Management Settlement Credits ("CMSCs"), OPG submits that the treatment of CMSCs should be maintained as per EB-2007-0905.

CME and VECC were the only intervenors to directly address Segregated Mode of Operation ("SMO") and Water Transactions ("WTs") in their arguments. Both indicated that the OEB should maintain its original decision and impute revenues for both of these services during the test period on the basis of the average net revenues earned during the past three years.

However, the submissions of CME and VECC ignore the fact that the world changed in 2009 as a result of the completion of the high voltage DC intertie between Ontario and Quebec (Ex. G1-T1-S1, page 6, Tr. Vol. 1, p. 41). The unchallenged evidence from OPG was that the completion of this tie means that market participants can access the Ontario market directly through this intertie and thus there is much less need for SMO (Ex. L-01-123).

The effect of this new world can be seen directly in the level of net revenues earned by OPG after the intertie was completed. In fact, the new intertie has changed OPG's SMO revenue picture so fundamentally that for the 12 months up to the end of August 2010 OPG had a net loss of almost $1M on SMO (Tr. Vol. 1, p. 41). In contrast, the three year rolling average methodology imputed $6.6M of net revenues for 2010 to be returned to ratepayers. The existence of the intertie is truly a "game changer" and the OEB should not ignore its impact on the net revenues likely to be earned during the test period. In OPG's submission, the OEB has an obligation to use the best evidence available to it in setting just and reasonable rates. And with respect to SMO, the best evidence is that the net revenues earned prior to the completion of the new intertie are in no way indicative of the net revenues that OPG will earn in the post-intertie period and during the test period.

In support of its submissions, CME makes the point that over time the three-year averaging mechanism will correct itself (CME argument, para. 208). OPG concedes that the 3-year rolling average will eventually begin using only data from the post-intertie period and thus will eventually begin to produce net revenue forecasts that reasonably reflect OPG's net revenues going forward. However, during the period while the mechanism is correcting itself, OPG will have returned to ratepayers many millions of dollars more that it earned on these transactions. It is hard to imagine that CME would counsel patience with the mechanism if ratepayers were the ones suffering a financial impact for the test period.

VECC notes in its argument that OPG earned $12.8M (should be $12.3M as per Ex. L-14-026) in excess of the imputed SMO and WTs net revenues in 2008 (VECC argument, para. 56). They suggest, in essence, that this bad forecast on the high side in 2008 is justification for using a forecasting methodology that we know to be wrong for the 2009-2012 period. OPG submits that this is false logic and should be rejected by the OEB.

The goal of rate setting for a future period should be to use the best information and most accurate forecasts. OPG also notes that in the post-intertie world, use of the 3-year rolling average formula for SMO and WTs produced an actual loss for OPG of $5M in 2009. In addition, based on its experience over the 12 month period prior to August 2010, referenced earlier, OPG expects to be significantly below the 2010 imputed SMO revenues of $6.6M. And finally, over the test period, OPG is expecting a loss of approximately $13M on SMO and WTs unless the 3-year averaging methodology is changed (Ex. L-14-026).

Accordingly, for all of the reasons articulated above, OPG submits that its proposed methodology should be accepted for the test period. Beginning in 2013, OPG would have no objection to returning to the 3-year rolling average methodology since by that time the methodology would be based on data from the post-intertie period and thus would begin to produce reasonable forecasts for use in rate setting.

CME submitted that if the OEB was persuaded to adopt OPG's proposed forecasting methodology, that is should create a deferral account to capture 75 per cent of the SMO and WTs net revenues earned beyond that included in rates for the test period (CME argument, p. 56). This amount would be returned to ratepayers in the next application. OPG notes that there is no evidentiary basis for this proposal. The concept of "sharing" was discussed in EB-2007-0905, with OPG's setting out its views on the merits of sharing in its final argument at page 104.

Water transactions have similarly been impacted by significant changes in market prices experienced during 2009 (Ex. G1-T1-S1, pp. 7-8). Given that the factors that caused market prices to decline in 2009 are expected to remain in force during the test period (Ex. G1-T1-S1, p. 7, lines 23-29; Tr. Vol. 2, p. 90), continued use of the 3-year rolling average methodology will result in additional financial losses for OPG. In addition, once the Niagara Tunnel comes into service in 2013, the volume of WTs is expected to decline substantially (EB-2007-0905, Ex. G1-T1-S1, p. 13, lines 10-11). Both of these developments argue for a change in the methodology, as proposed by OPG.

OPG notes that neither CME or VECC challenged OPG's evidence with respect to depressed market prices. In OPG's submission, they simply want to continue the 3-year methodology because it produces a lower revenue requirement and there is no consideration as to whether or not this reduction is reasonable in light of the facts. Similarly, neither CME not VECC have looked beyond the test period to understand the implications after 2012. For both of these reasons, and to ensure that rates are set using the most accurate forecast available, OPG submits that its proposal to use the most recent year's net revenues as the basis for the test period forecast is appropriate.

3.4 CAPITAL PROJECTS

> **Issue 4.1** - Do the costs associated with the regulated hydroelectric projects, that are subject to section 6(2)4 of O. Reg. 53/05 and proposed for recovery, meet the requirements of that section?
>
> **Issue 4.2** - Are the capital budgets and/or financial commitments for 2011 and 2012 for the regulated hydroelectric business appropriate and supported by business cases?
>
> **Issue 4.3** - Are the proposed in-service additions for regulated hydroelectric projects appropriate?

Intervenors and Board staff filed submissions on three capital projects: the Niagara Tunnel project; the St. Lawrence Power Development Visitor Centre; and the Sir Adam Beck I ("SAB I") G9 rehabilitation project. Each of these projects is considered separately below.

In addition, the PWU submitted that OPG should be directed to file information on the demographics of its regulated hydroelectric assets in any future payment amounts application (PWU argument, para. 129). This proposal should be rejected as it would require a complex analysis (Tr. Vol. 2, pp. 7 and 11) and its value has not been demonstrated. OPG's Hydroelectric business determines its investments "based on operating criteria, based on aging, based on reliability, all those factors" (Tr. Vol. 2, p. 12). OPG's use of Plant Condition Assessments, Life Cycle Plans and inspection and repair programs (Ex. F1-T1-S1, Section 2.0) illustrate the comprehensive nature of its investment management philosophy. Prudent investment decisions are determined using a suite of information, not a single chronological age. In OPG's submission, the PWU's proposal should be rejected.

Niagara Tunnel Project

AMPCO, CCC and SEC submit that OPG should file regular status reports to the OEB in respect of the Niagara Tunnel Project. OPG submits that regular reporting should not be required as there is limited, if any, incremental value to the proposed reporting given that the project that is well advanced and is expected to be in-service in 2013. The proposed reporting will add unnecessarily to OPG's regulatory burden and costs.

AMPCO provides no rationale for its request for progress reports. CCC submits that progress reports will assist in the final assessment of the project. With the project forecast to enter rate base in 2013, a prudence review of the Niagara Tunnel project will be conducted during the next hearing. This review will undoubtedly entail a significant volume of detailed evidence. Given that the record in this hearing closed in November, it will only be 16 months before OPG is making a comprehensive filing on the project as part of its next rates application scheduled for the end of Q1 2012. That is too short a period of time, in OPG's submission, to require additional interim reporting on this project.

For those wanting to follow the progress of this project, OPG provides regular information on the Niagara Tunnel project through news releases, financial reporting (i.e., Management's Discussion and Analysis) and its website. CCC specifically requests that any updated copies of the Project Execution Plan for the project be filed, stating that the OEB and intervenors should have the same opportunity to assess the progress of the project as OPG Board of Directors. OPG disagrees. The OEB does not have the same role as the OPG Board in overseeing and managing the project. Any reporting to the OEB should be focused on the specific information required to efficiently monitor and regulate OPG's prescribed facilities and not be required just because it is provided to OPG's Board.

SEC suggests that future mid-year reporting on the project would allow the OEB to hold a mini-hearing on the project if it saw problems (SEC argument, para. 4.1.6). SEC suggests that this mini-hearing might lead to the OEB putting in place "checks and balances" that would govern project spending (Ibid.). Importantly, SEC cites no precedent or legal basis for the OEB assuming a quasi-project management role during the course of a major project. OPG submits that the role suggested by SEC is not a proper role for the OEB and would create a conflict with its later duty to conduct an independent prudence review. For these reasons, SEC's request for mid-year reporting should be rejected.

St. Lawrence Power Development Visitor Centre

A number of intervenors[10] submitted that the costs (both capital and OM&A) for the St. Lawrence Power Development Visitor Centre should be entirely disallowed. Both SEC and OPG disagree with this position. Board staff, AMPCO and CCC suggest that since the Visitor Centre is not "required for the continued operations of the Saunders Generating Plant," (Board staff argument, p. 23) it has no place in the regulated hydroelectric rate base. Energy Probe similarly argues that the Visitor's Centre is outside OPG's mandate to provide electricity.

In OPG's submission, these views are too narrow and do not reflect the realities of operating a major power plant in the modern world. This view would lead one to believe that any activity, structure or component that was not directly tied to the flow of electrons is in some way superfluous to the generation business. Administration buildings, storage facilities, parking lots and sidewalks do not generate electricity either, but are nonetheless accepted as necessary infrastructure at a generating facility. In addition, these submissions are not consistent with the evidence. As explained by Mr. Shea, the visitors centre is important to good relations with the local communities and good community relations are critical to the continued smooth operation of the facility.

> In order for us to continue to operate the facility, we need to maintain that relationship with the host community. So in that regard, it sustains our ability to continue to operate that facility in a cost-effective manner, in a safe manner, in an environmentally responsible manner, and yet balance the needs of the community. And city of Cornwall, and, of course, the Mohawks of Akwesasne. (Tr. Vol. 1, p. 52)

And as Mr. Shea explained, the local communities can have real, practical impacts on the operation of OPG's facilities.

[10] Board Staff, AMPCO, CCC, CME, EP

> They have the ability to lobby with the provincial government. There are a number of interactions that take place on a day-to-day basis that can be easier or more difficult, you know, building permits and different interfaces with the community, just in terms of the day-to-day activities. And those could be either more difficult or less difficult. (Tr. Vol. 1, p. 53)

Board staff and Energy Probe also submit that OPG has not demonstrated that the Visitor Centre provides a benefit to ratepayers. They dismiss the value of the water safety communications because it is presented in a "room-sized exhibit." OPG provides details on its waterways public safety program in Ex. A1-T4-S2, page 12. This program includes "development and delivery of public education and awareness materials." Nowhere in their argument has Board staff suggested this public safety program is not in the interest of ratepayers yet they propose to cut its delivery at the Visitor Centre. In fact, Board staff goes further and provides a degree of endorsement for the centre: "Board staff is not stating that it is inappropriate for OPG to have a Visitor Centre or that the Visitor Centre is not a valuable resource." (Board staff argument, p. 24)

Similarly, OPG includes its aboriginal relations function in its Base OM&A expense (Ex. F1-T2-S1, p. 13) and OPG's evidence is that "the centre will allow OPG to strengthen its relationship with the Mohawks of Akwesasne" (Ex. L-01-018) and that space in the Centre is dedicated to exhibits on the Mohawks of Akwesasne (Tr. Vol. 1, p. 155). Again, Board staff has made no suggestion that the aboriginal relations function is not appropriately recovered from rates yet they propose to disallow the cost of a facility that contributes to delivery of that function.

OPG fully supports SEC's submissions that regulated utilities should be good corporate citizens and that the St. Lawrence Visitor Centre is a legitimate expense in accordance with this expectation (SEC argument, paras. 4.3.6 to 4.3.9). Indeed, OPG's Memorandum of Agreement with its shareholder requires that OPG operate in accordance with the highest corporate standards in the areas of social responsibility and corporate citizenship (Ex. A1-T4-S1, Attachment 2). OPG's categorization of the project as sustaining is consistent with this requirement.

Finally, Board staff suggests that a portion of the costs of the project should be allocated to the unregulated hydroelectric facilities. OPG adopts the submissions of SEC on this issue (SEC argument, paras. 4.3.10 - 4.3.11). As stated by Mr. Shea (Tr. Vol. 1, p. 155):

> The only reason for locating the centre in the city of Cornwall is because of that facility being there. So the regulated facility is the reason for it being in that location.
>
> The majority of the floor space, with only a couple of exceptions, you know, as we've already talked about, has to do with the construction of the facility and the seaway, and all the programs that are directly related to it: the First Nations Mohawks of the Akwesasne, our biodiversity programs, environmental programs that relate directly to that station.
>
> So the majority of the exhibits and, therefore, the usefulness of the facility is directly attributable to that particular asset.

Accordingly, OPG submits that the OEB should include the St. Lawrence Power Development Visitor Centre within its 2010 rate base, and also allow the $0.5M of annual OM&A expenses required to operate and maintain it.

Sir Adam Beck I G9 Rehabilitation

In its submission, AMPCO requests a reduction in proposed rate base of $1M associated with the SAB I Unit G9 rehabilitation, citing cost and schedule delays as justification. This proposed disallowance is inappropriate and should be rejected. The project is, in fact, on schedule and on budget as per the project's approved business case summary presented at Ex. D1-T1-S2, Attachment 1, Tab 4 and discussed at Tr. Vol. 1, p. 129.

In making its submissions on the project, AMPCO has not suggested that any of the costs associated with the project are imprudent or provided any justification for the OEB to make such a finding. Instead, they base their recommendation for a disallowance on the fact that there has been an increase in the costs of the project relative to the information presented in EB-2007-0905. However, they do not seem to give any weight to the fact that, at the time of the last hearing, the final budget for the project had not been determined and there was not yet a finalized business case for the project since it was still in the concept phase (Tr. Vol. 1, page 130):

> MR. LORD: So, relative to -- when you say that the upgrade is currently on schedule and on budget, what you really mean is that the project is currently tracking $2.1 million over the original budget and albeit a year later than originally anticipated to come into service?
>
> MR. MAZZA: Well, what it means is it's relative to when the project was approved by OPG. At the time of the last hearing that was -- there was no business case yet established for the -- for that particular project. It was basically in concept phase. And that was a concept phase level estimate that we refer to.

Consistent with OPG's project management process, it is the approved business case summary that establishes the project budget and schedule (Ex. D1-T1-S1, p. 11) not information from the concept stage.

AMPCO recommends that the OEB require OPG to provide information on changes to project budgets and schedules from previous applications (AMPCO argument, para. 110). OPG submits that no revisions to the filing guidelines are required in this regard. The filing guidelines with respect to capital projects changed between EB-2007-0905 and EB-2010-0008 to require the filing of business case summaries for projects greater than $10M (Filing Guidelines for Ontario Power Generation, Inc, July 27, 2007, EB-2006-0064, p. 14 and November 27, 2009, EB-2009-0031, p. 14). Since business case summaries are required for this and all subsequent applications, it will be apparent when a project has moved from the development phase to an approved project and what the approved project budget and schedule is.

AMPCO also submits that OPG should have applied its experience from the G7 project to the G9 project. They also suggest that OPG should have taken advantage of the delay in the tunnel project to re-organize the G7 project (AMPCO argument, para. 111). OPG agrees and the evidence shows that it did exactly that when it prepared its final budget and schedule for the G9 project. In EB-2007-0905, the concept level estimate prepared for the project was $30M with an in-service date of 2009. The increase in costs and changes in project schedule in the approved business case summary from the EB-2007-0905 application have been fully explained and justified in the evidence in this proceeding (Ex. D1-T1-S2, Attachment 1; L-02-008; Technical Conference Transcript, pp. 15-17; JT1.1; Tr. Vol.1, pp.129-134). And that evidence shows that the final budget and schedule in the business case summary took advantage of the lessons learned from the SAB I G7 frequency conversion project.

At the time of the preparation of the EB-2007-0905 evidence, the SAB1 G7 frequency conversion project was just starting (EB-2007-0905, Ex. D1-T1-S1, p.1 lines 17-19). Therefore, it is unreasonable to have applied lessons learned from G7 to estimates for subsequent units before meaningful work on the G7 unit had commenced. As described in Interrogatory L-02-008, leading up to the approval of the SAB1 Unit G9 in August 2008, OPG applied its experience from the G7 project and its knowledge of the Niagara Tunnel project delay.

As the G9 project is currently on schedule and on budget against its approved business case summary and no intervenor has argued that any costs related to the project are imprudent, the full 2010 rate base addition of $32.1M should be approved.

3.5 PRODUCTION FORECAST

Issue 5.1 - Is the proposed regulated hydroelectric production forecast appropriate?

OPG is seeking approval of a test period regulated hydroelectric forecast of 38.4 TWh (19.4 TWh in 2011 and 19.0 TWh in 2012) for the regulated hydroelectric facilities (Ex. E1-T1-S1, Table 1). With the exception of the treatment of surplus baseload generation ("SBG"), which is considered below, no intervenor objected to OPG's regulated hydroelectric production forecast, and as such, and for the reasons set out in OPG's evidence and AIC, it should be approved as filed.

Surplus Baseload Generation

Board staff, AMPCO, CCC, CME, SEC and VECC argue against OPG's proposal to adjust its regulated hydroelectric production forecast to account for forecast levels of SBG. As indicated in its AIC (p.12, lines 8-17), OPG used the best information available to it at the time that the evidence was produced to arrive at its forecast of SBG for the test period. While the amount of SBG that will be experienced during the test period is subject to disagreement, the fact that the phenomenon exists, and will continue to exist in the test period, is supported by the evidence (J2.2) and has not been challenged.

Board staff submits that the financial benefits of including SBG in the production forecast are “one way”, accruing exclusively to OPG (Board staff argument, p. 83). This is not correct. If the actual amount of SBG were less than the amount included in the hydroelectric production forecast, then OPG would benefit. However, if the actual amount of SBG were higher than the amount included in the production forecast, as was the case in 2009 when no SBG was included and actual SBG was 0.2 TWh, ratepayers benefit at OPG’s expense.

Board staff also suggests that SBG conditions are qualitatively equivalent to deviations of actual water conditions from forecast water conditions and this view leads them to propose that there be no allowance for SBG in the production forecast (Board staff argument, p. 83). This analysis of the situation is flawed and not consistent with the evidence filed in this proceeding. As explained in detail in Ex. E1-T1-S1, OPG’s hydroelectric production forecast takes into account a wide range of “conditions” including, water conditions, seasonal restrictions on the Beck waterways, NYPA’s discharge capabilities, losses attributed to AGC, condense mode operations, ice and weed conditions, etc. Just because significant SBG is a relatively recent phenomenon does not mean that it should be excluded from consideration when OPG is developing its production forecast. Excluding it as Board staff suggests would be inconsistent with the treatment of other conditions and would not result in the most accurate forecast for the test period.

Board staff’s comparison to the treatment of water conditions is also incorrect. OPG <u>does</u> include its best forecast of water conditions in the development of its production forecast. The existence of the water conditions variance account is a recognition that actual water conditions can be different than OPG’s best forecast and this difference can have a material impact on costs. Therefore, treating SBG in a manner similar to water conditions would lead one to include a forecast of SBG in the production forecast for the test period.

A number of parties have suggested that the OEB approve a variance account for SBG. Given the relative newness of high levels of SBG on the system, OPG can understand the rationale for this proposal and can support it. However, that account should be structured to capture variances from the best forecast of SBG and not artificially set at zero as some have suggested.

Surplus Baseload Generation was a material factor in OPG's regulated hydroelectric production in 2009 (Ex. L-02-019) and 2010 (J1.1) and it is expected by the IESO that SBG will exist in the test period (J2.2). While there may be uncertainty regarding the level of SBG that will impact the regulated hydroelectric facilities over the test period, the amount will certainly be greater than zero. In order to reduce the potential for a large balance in the proposed SBG variance account, OPG proposes that a forecast of SBG be included in the hydroelectric production forecast and that the variance account should record the difference between actual and forecast SBG.

If the OEB is not prepared to accept the test period forecast of 1.3 TWh included in the application, then OPG submits that the OEB should at least accept a SBG forecast of 0.2 TWh for each of 2011 and 2012. This is approximately the level that OPG actually experienced at its regulated hydroelectric facilities in 2009 (Ex. L-02-019) and it corresponds to OPG's forecast for 2010. While the actual amount of SBG in 2010 is expected to be below 0.2 TWh, this is largely a result of reduced water inflow across Ontario from an unusually dry year (J1.1). In addition, OPG expects that the level of SBG in the test period will be higher than 2009 as a result of increased levels of renewable energy (Undertaking J2.3) and additional baseload generating capacity associated with the expected return to service of the refurbished Bruce Power units (Undertaking J1.7).

The question of how to reconcile an SBG variance account was also addressed by a number of intervenors in their submissions.[11] Board staff (with VECC) suggested a means that included "reference to IESO orders (if applicable), general market conditions (total demand, total baseload supply) and audited production reports from the SBG-affected generation units that demonstrate deviations from near-time trend production

[11] Board Staff, AMPCO, CME, SEC, VECC, CCC, PWU

that is contemporaneous with SBG market conditions" (Board staff argument, page 84). Others, including AMPCO and SEC, argued for reconciliation for SBG levels that are substantiated exclusively by IESO "directives".

The AMPCO and SEC proposal is completely unworkable. Under the market rules, the IESO only issues directives to market participants when the normal market mechanisms, including dispatching generation down or off and approving exports, have failed to mitigate the SBG and the IESO is now directing market participant activities based on a need to ensure overall system reliability.[12] This does not represent how SBG is normally managed and would significantly understate the quantity of SBG actually experienced by the market and OPG.

Further, these account reconciliation proposals were first raised in argument, were not considered during the hearing and are completed untested. As a result, OPG submits that if the OEB decides to establish a SBG variance account then it should be based on OPG's modified version of the Board staff proposal. Under OPG's proposal, the reconciliation would be based on any IESO order or instructions (if applicable), general market conditions (e.g., total demand, total baseload, total supply) and actual production reports from the SBG-affected generation units that show deviations from production that are contemporaneous with SBG conditions.

CCC proposes that if OPG's actual production continues to exceed the forecast, the OEB should consider this when assessing how much to clear from the SBG variance account in the next proceeding (CCC argument, para. 62). This proposal ignores the existence of the Hydroelectric Water Conditions Variance Account which holds ratepayers harmless in the event that OPG's production exceeds the forecast due to changes in water conditions and therefore should be rejected.

Finally CME, in its submission at paragraph 174, questions electricity sector policy regarding the integration of increased renewable resources into Ontario's generation mix. While it is true that increased levels of wind generation contribute to increasing

[12] The IESO's statutory reliability mandate is recognized in the Electricity Act, 1998 Section 5. (1) c. which is given effect by the Ontario Market Rules, Chapter 5, Section 3.2.1. Possible control actions in the event of reliability related issues are indicated in Market Manual 7.4 (IESO Controlled Grid Operating Policies) Appendix E (Emergency Operating State Control Actions).

SBG, and that nuclear units are generally not designed to follow load, holding OPG's regulated hydroelectric resources financially responsible due to their ability to quickly and safely contribute to resolving SBG in real time is wholly inappropriate. SBG is a market condition and penalizing those resources within the market that can help to mitigate the condition is perverse. CME would be better off focusing its attention on a Stakeholder Engagement activity (SE91 – Renewable Integration) initiated by the IESO in November 2010 which addresses this concern.[13]

3.6 HYDROELECTRIC INCENTIVE MECHANISM

Issue 9.2 - Is the hydroelectric incentive mechanism appropriate?

Submissions on the Hydroelectric Incentive Mechanism ("HIM") were received from Board staff, CCC, CME, EP, and VECC, many of which called for the implementation of a sharing mechanism.[14] OPG opposes revenue sharing in respect of the HIM. Sharing would reduce OPG's revenues from the HIM while leaving it with the same level of risk. It would also push OPG to operate with a flatter profile that it otherwise would.[15] Also, and perhaps more importantly, the consumer already shares in benefits associated with the incentive mechanism (Ex. E1-2-1, p. 2, lines 22-27).

As indicated by OPG (Tr. Vol 1, p. 112), any sharing mechanism will tend to reduce the frequency and overall utilization of the Pump Generating Station ("PGS"), ultimately resulting in less time-shifting of generation. This reduction will also decrease HIM-related revenues since OPG will operate the facility in a more conservative fashion. As indicated during the hearing, there is a financial risk associated with operating the PGS (Tr. Vol. 1, pp. 35-36, Tr. Vol. 2, p. 119). That risk relates to the potential that OPG will fail to recover the costs associated with PGS operation; costs that are not included in OPG's revenue requirement.[16] Sharing of revenues implies that OPG will assume the same risks, but will only realize a portion of the return. At a minimum, any sharing mechanism must be explicit that it is the "net revenues" that are being shared, not the gross revenues.

[13] http://www.theimo.com/imoweb/consult/consult_se91.asp
[14] Some form of sharing was endorsed (to varying extents) by all intervenors making a HIM submission except EP.
[15] While Ex. L-14-037 deals with the absence of a HIM, it is relevant to the question of sharing.
[16] The production forecast does not include all incremental economic pumping.

This reduction in PGS utilization not only reduces the amount of generation that is time-shifted, but also reduces the amount of consumer benefit which accrues to ratepayers (Ex. E1-2-1, p. 2). So while intervenors may view sharing as beneficial because of the impact on OPG's payment amounts, it comes at the cost of a reduced market benefit. What they gain in one pocket, they lose from the other.

Board staff went to great lengths to try and show that OPG's illustrative consumer benefit calculation was flawed (Tr. Vol. 1, pp. 86-89). The implication was that somehow OPG should consider the combined effect of the Hourly Ontario Energy Price ("HOEP") and the Global Adjustment directly when making PGS pump decisions, a curious proposal which is not possible.

Board staff suggests that the market price is largely irrelevant, in terms of what consumers actually pay for their electricity (Tr. Vol. 1, p. 86). However, according to the OEB's own website, "[t]he Regulated Price Plan is a forecast of a blend of the regulated prices for Ontario Power Generation's (OPG) nuclear and baseload hydro facilities (needed 24/7 all year), existing contract prices for supply from non-utility generators <u>and the Board's forecast of electricity prices in the open electricity market over the next 12 months</u> (emphasis added). And any decrease in HOEP does not necessarily result in a one-for-one increase in Global Adjustment payments. For example, while it is true that many contracted generators whose contract price was higher than HOEP would recover the HOEP reduction of $1.14/MWh through the Global Adjustment, there are also generators who are not so contracted (e.g., OPG's unregulated hydroelectric assets) and therefore do not recover this drop. Hence, any drop in HOEP will still result in savings to consumers.

Board staff uses untested percentages to try and erode the consumer benefit from the operation of the HIM. OPG understands that a significant percentage of generation is not paid solely on the basis of HOEP. However, OPG's example was constructed to illustrate how *market prices* are affected by the operation of the PGS. As indicated at Ex. E1-T2-S1, page 2, demand weighted market prices were reduced by approximately $1.14/MWh. This represents a tangible reduction to the hourly price of electricity and shows how OPG, by using market based signals (price spreads) positively impacted market price for consumers. To carry forward the discussion, as Board staff did, to matters of the Global Adjustment takes OPG to a realm over which it has no control. OPG has always based its decisions on market price spreads. Therefore, it is logical for OPG to demonstrate the success of the mechanism in those terms.

Energy Probe dedicated considerable space in its argument (EP argument, pp. 37-48) to further discussion of its “thought experiment” (now referred to as the “cartoon-like scenario”). (Tr. Vol. 1, p. 180). Boiled down to its essential element, Energy Probe is once again requesting that pump energy be removed from the calculation of the hourly volume (defined at Ex. E1-T1-S1, page 1). OPG disagreed with this position in EB-2007-0905, and continues to disagree with it in EB-2010-0008.

In its final argument in EB-2007-0905 (pp. 132-134), in Undertaking response J15.6 (same proceeding), and in cross-examination during EB-2010-0008 (Tr. Vol. 1, p. 180) OPG accepted that pumping lowers the hourly volume. However, to artificially increase the net energy used to determine the hourly volume by ignoring the energy used for pumping creates a fictional situation where the energy threshold is set higher than what is achieved in any given month. Regardless of how a threshold is set, if it is set artificially high it will tend to reduce the benefits achieved, for both OPG and the consumer. Energy Probe’s concern about potential PGS over-use was unfounded in EB-2007-0905, and continues to be so in EB-2010-0008.

4.0 NUCLEAR

4.1 BUSINESS PLANNING AND BENCHMARKING

> **Issue 6.4** – Is the benchmarking methodology reasonable? Are the benchmarking results and targets flowing from those results for OPG’S nuclear facilities reasonable?

> **Issue 6.5** – Has OPG responded appropriately to the observations and recommendations in the benchmarking report?

OPG submits that the benchmarking study (Phase I and Phase II) prepared by ScottMadden (the “ScottMadden Report”) should be accepted by the OEB. The methodology employed was reasonable and OPG has responded appropriately to the study. Although, for the most part parties were supportive of OPG's benchmarking efforts, various parties made submissions, which OPG responds to below.

4.1.1 Continuous Improvement

In considering the ScottMadden Report and OPG's response to it, Board staff has improperly applied the term "continuous improvement." Board staff has incorrectly and arbitrarily used this concept to advocate for unrealistic targets in individual metrics to support reducing particular aspects of revenue requirement (Board staff argument, pp. 44-45).

OPG has an obligation to "seek continuous improvement in its nuclear generation business" in the Memorandum of Agreement with its shareholder (Ex. A1-T4-S1 Attachment 2). OPG took this obligation into consideration when developing the 2010-2014 business plan that forms the basis for this application (Tr. Vol. 3, pp. 22-23). OPG's success in this regard is evident in the targeted cost and performance improvement included in that business plan (Ex. F2-T2-S1, p. 16; Ex. F2-T2-S1, pp. 1-2).

The ScottMadden Report (Phase II), states that "opportunities remain for 'continuous improvement' beyond the current business planning horizon" (Ex. F5-1-2, p. 31). When Board staff counsel asked about the intent of that statement, ScottMadden responded that the point of the statement was that OPG "should be dedicated to a philosophy of continuous improvement." In effect, there are always opportunities beyond the planning horizon to make additional improvements (Tr. Vol. 3, p. 19).

Consistent with this, OPG has acknowledged in testimony that OPG took seriously the criticism of the OEB in its last Decision with respect to its approach to benchmarking, sought an external source to assist in taking a holistic view of OPG's performance and produced a study that did not "sugar coat" the results. This was a "big change" and major achievement for OPG (Tr. Vol. 3, pp. 67-68). As stated by Mr. Tremblay:

> …we looked at ourselves critically, to owning the improvement plans and the commitment through the business planning process.
>
> And I think the point that ScottMadden was making is that you can't make these changes business as usual. You can't go on and expect

> those to take fruit, and then move on, because there is resistance that will take place.
>
> And so we put very capable people in charge of this, dedicated them to the integrated improvement initiatives, and then put an accountability framework in place. (Tr. Vol. 3, p. 179)

The OEB should not construe continuous improvement in the manner Board staff proposes. OPG submits that continuous improvement is an overarching approach in which OPG critically assesses itself and the gaps in performance, considers best practices and takes constructive steps to improve. By contrast, Board staff only looked at isolated aspects of OPG's business. A narrow focus on a few aspects ignores the overall achievements in the business plan.

Also, as discussed further below, Board staff is focused only on the value for money performance objectives and the total generating cost metrics. OPG's evidence is that there are nineteen benchmarking measures that address the four OPG cornerstones of safety, reliability, human performance and value for money, and that all of the measures need to be considered as part of continuous improvement (Tr. Vol. 3, pp. 48 and 125).

Based on a misinterpretation of continuous improvement, Board staff incorrectly uses the benchmarking results as the basis to argue for a decrease in OPG's proposed revenue requirement. Board staff makes submissions without a full review of the evidence and on an arbitrary basis. OPG submits that OPG's payment amounts should be determined based on its forecast costs and production as supported by the evidence. While benchmarking can help the OEB assess the reasonableness of OPG's forecast, it cannot be used as a substitute for an evaluation of OPG's forecast costs and production.

Notwithstanding the extensive benchmarking study and the overall achievements in targeted cost reductions and improved performance as set out in the business plan, Board staff make recommendations or submissions in four areas without justification and without following correct regulatory principles of evaluating the reasonableness of OPG's forecast costs and production based upon the facts presented in evidence. In effect, the Board staff's submissions were no more than arbitrary conclusions. Each area raised by Board staff will be considered in turn.

(i) Darlington Total Generating Cost

Board staff has reached a flawed conclusion that OPG has not set challenging targets for Darlington with respect to total generating cost ("TGC"). With respect to the 2011 and 2012 TGC for Darlington, Board staff has misunderstood and mischaracterized OPG's evidence by stating that the 2011 and 2012 targets were derived by assuming 4 per cent inflation (Board staff argument, p. 44). The reference to 4 per cent inflation is related to ScottMadden's top-down target setting methodology. OPG inflated the 2009 industry generation costs benchmark by 4 per cent per year to derive a 2014 industry benchmark (Ex. L-12-029). By comparison, OPG's internal 2010-2014 TGC targets were finalized through business planning process based on OPG's projection of TGC and were not derived based on an assumed 4 per cent inflation rate. The inflation assumption for OPG's business planning for the test period was approximately 2 per cent (Ex. L-06-001, Attachment 1).

Board staff has ignored OPG's evidence and testimony on why TGC costs are projected to rise over the period 2008-2012, and that they do not include an assumed 4 per cent inflation rate.

As shown in the table included in the response to Interrogatory L-12-029, the major driver of the increase in OPG's TGC metric is the fuel cost component, which reflects the rise in world commodity fuel costs. Also, as shown in L-12-029, Darlington's proportion of capital costs are also projected to increase in 2011 and 2012 compared to 2008. Non-fuel operating costs (i.e., including nuclear OM&A plus corporate allocated costs excluding other post-employment benefit costs ("OPEB") are forecasted to increase from $718.9M to $737.4M or $18.5M, representing an average yearly increase of 0.6 per cent, not 4 per cent as asserted by Board staff.

The thrust of OPG's evidence on Darlington TGC is that while OPG and other nuclear operators share inflationary pressures (Tr. Vol. 3, p. 57, line 5), OPG is reducing Darlington's costs and improving TGC performance through cost control and other initiatives in business planning and thereby narrowing the performance gap with its peers.

(ii) Non-Fuel Operating Cost

By reference to OPG's 2011 and 2012 non-fuel operating cost targets, Board staff submits that OPG either did not actually achieve $260M in net savings or OPG should be able to at least maintain the three year average of $25.10 per MWh if OPG did achieve those cost savings. Discussion relating to the $260M in net cost savings is found at Section 4.2 Base OM&A expenditures.

With respect to non-fuel operating costs, OPG's 2008 actual non-fuel operating costs as shown in its benchmarking reports exclude OPEB. This definition is consistent with that of the EUCG database which is used for benchmarking (Tr. Vol. 3, pp. 155-156). However, the OPG's test period targets for 2011 and 2012 non-fuel operating costs include OPEB to be consistent with OPG's business planning.

In Ex. L-12-029, OPG was asked to compare its 2011/2012 total generating cost targets to the 2008 actual results. OPG updated its response to reflect the need to remove OPEB costs from the 2011 and 2012 non-fuel operating cost targets as shown in the corrected version of L-12-029.[17] The revised non-fuel operating costs excluding OPEB are $25.02 per MWh for 2011 and $25.43 per MWh for 2012.[18] Therefore, whether one compares the three year average 2008 non-fuel operating costs value of $25.10 per MWh or the one year 2008 value of $24.88 per MWh relative to the 2011 or 2012 non-fuel operating costs targets of $25.02 per MWh or $25.43 per MWh, there is little or no growth in this metric. This result is consistent with net cost savings and reflects the aggressive targets undertaken by OPG. Once again, Board staff has offered a conclusion that is at odds with the underlying evidence.

(iii) Radiation Protection

Board staff took the position that the OEB should deny recovery of $2.2M in OM&A for compensation costs related to the elimination of thirteen radiation protection staff identified in the Phase II ScottMadden Report. Board staff's recommendation was premised wholly on the fact that a recommendation had been made in the ScottMadden

[17] The one year 2008 non-fuel operating costs of $24.88/MWh did not change in the corrected L-12-029 version as the 2008 actuals excluded OPEB.
[18] A similar adjustment should also have been made to response to Interrogatory L-12-026.

Phase II Report and only one of the thirteen positions had been eliminated. OPG notes that in calculating the proposed reduction of OM&A Board staff failed to account for the one position that OPG has eliminated (Tr. Vol. 3, p. 27). In taking this position, Board staff's submissions fails to detail in full the reasons OPG provided to explain why only one of the thirteen positions was eliminated.

Mr. Tremblay clearly indicated in his testimony that this recommendation was held in abeyance "to further study [it] as part of the consolidation of Pickering A and Pickering B, which is currently underway" (Tr. Vol. 3, p. 28).

Furthermore, Mr. Tremblay indicated that: "…in the last 6 months to 8 months there has been a fairly significant industry issue around alpha contamination. We have had to absorb that level of work and effort, and we are looking at that extra workload in the context of, you know, trying to be as efficient as possible."(Tr. Vol. 3, p. 29). The work associated with alpha radiation is a CNSC regulatory requirement and represents a significant amount of incremental work for OPG.

Based upon the foregoing, OPG has demonstrated a clear justification for not eliminating all of the thirteen positions especially given the fact that it is responsible for managing the day-to-day operations of the facilities to ensure that they are reliable and safe. Given this responsibility and because circumstances had changed since the preparation of Phase II of the ScottMadden Report, the appropriate decision was made not to eliminate the thirteen positions. OPG submits it would not be prudent or responsible to blindly eliminate all thirteen positions as suggested by Board staff in light of the circumstances explained by Mr. Tremblay. As a result, Board staff's recommended revenue requirement reduction should be rejected.

(iv) Forced Loss Rate ("FLR")

Board staff also has made submissions with respect to reduction of revenue requirement because of FLR for Darlington. OPG's submissions on Darlington FLR are included under its submissions on the nuclear production forecast set out at Section 4.7**.**

OPG Staff Level Benchmarking

In their submission Board staff argues that the OEB should direct OPG in the next application to file a similar staffing analysis undertaken by ScottMadden in Appendix G of the Phase 2 report (Board staff argument, p. 46).

OPG submits that the OEB should not direct OPG to file such an analysis. Although OPG considers all 19 of its benchmarks as important, a key metric is TGC/MWh. Staffing and remuneration are factors that drive cost. Both can vary. However, the key issue for ratepayers is the overall level of costs. These costs form part of TGC/MWh and related cost metrics and as such these cost-related metrics should be the basis of the benchmarking.

As noted above, benchmarking is merely a tool to aid in assessing the reasonableness of forecast costs. The OEB's determination on that forecast is based on the facts and assumptions underlying the forecast. Furthermore, the applicant bears the onus of showing costs are reasonable and prudent. As such, it should be to the applicant’s discretion to decide what evidence to produce in support of its proposals. As a result, component aspects of OPG's benchmarking initiative should not be prescribed, since any particular component may not be relevant in future proceedings. Board staff has not shown why the provision of the requested staffing analysis should be captured in a direction from the OEB and their proposal should not be accepted.

CANDU versus U.S. Reactors

Board staff made comments with respect to the advantages and disadvantages of CANDU reactors compared to pressurized water reactors (“PWR”) and boiling water reactors (“BWR”). OPG’s submits that Board staff has understated the differences between the two reactor technologies. Board staff highlighted that CANDU has certain fuel cost advantages related to raw uranium fuel costs, reactor core efficiency and fuel assembly manufacturing costs. However, Board staff did not place this cost advantage in an appropriate context since it failed to mention Mr. Tremblay’s testimony which noted that CANDUs allow for on-line fueling which is an advantage, but there are offsetting cost disadvantages including extended outage times to address maintenance and inspections associated with the fuel handling machinery. For example, an extensive forced outage at Darlington in 2010 related to its on-line fuel handling machines (Tr. Vol.

6, p. 79) and the increase in FTEs at Darlington was related to fuel handlers needed due to increased fuel channel work (Tr. Vol. 5, p. 45).

In addition, in testimony Mr. Tremblay indicated that the CANDU reactor is more complex with more interrelated systems (Tr. Vol. 3, p. 183) and that the heavy water management enhances that complexity. In addition, there are technological differences between Pickering A, Pickering B and Darlington and these are revealed in terms of the operation of the plant and their vulnerabilities which account for some of the differences in performance (Tr. Vol. 3, p. 183).

As well, the pressure tubes are a life limiting component. Validating and verifying the safety case necessary for any changes to the reactor life for facilities such as Pickering B requires extensive work related to pressure tubes. Pressure tubes also drive the critical path through outages and is an extensive burden on the facility (Tr. Vol. 3, p. 184).

Another aspect is that the nuclear industry in the United States is much larger and more standardized, which provides better access to parts and components. With respect to safety and regulatory aspects, the U.S. system is much more deterministic and more efficient relative to the regulatory environment in Canada (Tr. Vol. 3, pp. 185-186).

Notwithstanding the forgoing, from the perspective of benchmarking Mr. Sequeira stated it clearly when he testified that:

> We have been doing benchmarks like this for a number of years, and the issue that often comes up very similar to this is trying to -- when there is a gap - and there is a gap here in total cost - trying to explain and, not only to explain, but to quantify every individual contributor. And often we are asked to adjust the benchmarking metrics to make them an absolute apples-to-apples comparison.
>
> What we have learned in the process of doing that for several years is that it is not productive. It is almost -- I wouldn't say "almost". It probably is impossible to absolutely quantify the contributions of every piece of technology. Every one of the plants, whether they're PWR or CANDU, is almost a unique design. No two are absolutely the same.
>
> When we try to adjust the benchmarks over time, it gets to the point that nobody believes the benchmarks anymore. I mean, it is like, Well,

> that's just a fabricated number that OPG wants to look at to compare themselves.
>
> My recommendation is that it is not ultimately doable, but, worse than that, I am more concerned with the impact on the discussion. And I would say that was part of the large cultural change in this particular exercise is coming to grips with the fact that we are not trying to explain why OPG is or should be equal to those other plants, but a recognition on management that this is just not acceptable. (Tr. Vol. 3, pp. 40-42)

Non-fuel Cost as a Benchmark

AMPCO took the position that a non-fuel cost escalator trend be applied to non-fuel generation costs because the inclusion of uranium costs in the calculation of the escalator trend will mask the underlying cost trend associated with total generating cost (AMPCO argument, para. 170-171).

However, OPG did use different inflation factors in setting the industry benchmarks:

> During the target setting process (Ex. F2-T1-S1, page 13) industry "inflation" assumptions were derived by ScottMadden and applied to the 2014 industry targets based on historical escalation rates derived from the Electric Utility Cost Group ("EUCG") database. Industry Non-fuel costs were escalated approximately 4.5 per cent per annum, fuel costs by 7.2 per cent per annum, and capital costs by 1.33 per cent per annum based on the EUCG historical data. This equates to an annual increase in Total Generating Costs of approximately 4 per cent." (L-12-029).

Nuclear fuel is only one component within total generating cost. For OPG it represented only 10 per cent of total generating costs in 2010, so applying varying escalation factors does not unduly distort the resulting metric.

SEC also argues that the appropriate metric is non-fuel operating cost, not total generating cost because of the uncertainty related to CANDU fuel costs (SEC argument, para. 6.4.4). OPG believes that the best approach is not to isolate one metric. OPG's position is that it intends to benchmark going forward all value for money metrics (total generating cost, non-fuel operating cost, fuel cost and capital costs per MW DER (as shown in the updated 2010 benchmarking report) (J3.5). OPG believes all 4 metrics provide important and relevant explanatory insight into performance. OPG does not support SEC's view that non-fuel operating cost should be the primary financial benchmark.

ScottMadden also noted that in regard to the potential that lower capital costs results in higher non-fuel operating costs, "the best way to address this difference is to utilize total generating cost per MWh (i.e., the sum of non fuel operating cost, fuel cost and capital costs) as the primary financial benchmark to eliminate any unintended impact of the capitalization policy on total operating costs per MWh." (Ex. F5-T1-S1, p. 123). OPG agrees and further submits that the best way to address and eliminate the impact, positive or negative, of fuel costs on total operating costs is to also use the total generating cost per MWh metric.

SEC also makes submissions with respect to the nature of the benchmarks used. In particular, it is SEC's position that OPG should aim to have the highest unit production with the lowest generating cost possible while meeting the safety requirements established by its management and monitored by the CNSC. (SEC argument, para. 6.4.12). However, SEC does not believe that the safety benchmarks are particularly relevant to the objective of economic regulation.

On the contrary, safety considerations have a direct influence on economic performance. Obviously, if a unit is shut down due to safety concerns, generation from that unit would decrease with a resulting increase in generating cost per unit output. As Mr. Tremblay stated, "Nothing will derail our program faster than a significant event." (Tr. Vol. 3, p. 176).

OPG submits that this is not an acceptable manner in which to consider the benchmarking results. In particular, it's important that the OEB recognize that OPG must balance a number of factors to ensure that nuclear power is delivered to Ontario in a cost-effective, safe and reliable manner. It is not just a purely economic exercise. As stated by Mr. Leavitt, "We will seek to set challenging but achievable goals for all nineteen of the benchmark measures. Cost is one of them. We can't lose sight of the fifteen non-cost measures as well." (Tr. Vol. 3, p. 48).

Conclusion

OPG submits that the OEB should assess OPG's benchmarking based on whether OPG has responded appropriately to the observations and recommendations in the benchmarking report and not in absolute terms based on the size of the remaining performance gap in 2011 or 2012. To this end, the OEB should evaluate whether (i) OPG has acknowledged and accepted the directional guidance of the benchmarking report, and (ii) whether OPG has embarked upon the necessary steps to narrow the performance gaps. OPG submits that the implementation of top down gap-based business planning, which resulted in the 2010-2014 Business Plan that underpins this application, is a very significant first step in narrowing the identified performance gap.

4.2 OM&A

Issue 6.3 - Is the test period Operations, Maintenance and Administration budget for the nuclear facilities appropriate?

4.2.1 Base OM&A

OPG submits that its proposed Base OM&A expenditures of $1,192.3M and $1,219.8M for the respective test years are reasonable and should be approved by the OEB. Board staff, SEC and AMPCO each made submissions in respect of Base OM&A. OPG replies to each in turn below.

Board Staff

In evidence relating to Base OM&A, OPG indicated that it had savings of $260M in the 2010 to 2012 period over 2008 levels. Fundamentally, Board staff misrepresents the evidence related to these savings. The evidence, however, is clear. Notwithstanding OPG being consistent in its testimony, in its written evidence, and in its responses to technical conference questions, Board staff continues to insist the stated level of savings is meaningless. Board staff has attempted to represent the savings that OPG has presented in a manner that is not supported by evidence.

The proposed savings are set out in Chart 2 of Ex. F2-T2-S1, page 16. OPG has consistently described the $260M in savings as follows:

Chart 2 of Ex. F2-T2-S1, page 16 shows a trend line from 2008 over a 5 year period to 2012. It is a normalized amount to provide an "apples-to-apples" comparison between 2008 and the period 2010 through to 2012. The normalization is accomplished by removing from OM&A, the amounts or factors that are not related to typical sustaining work, i.e., escalation, a 53rd week in 2012, Pickering B Continued Operations/refurbishment. Once these factors are removed, the OM&A levels can be compared between 2008 and the period 2010 through to 2012. In each year, some costs will have gone up and some will have gone down. (J4.3 p. 2, Tr. Vol. 4, p. 65, lines 1-12; p. 69, lines 1-7 and 25-28; p. 70, lines 1-10; p. 74, lines 21-24; p. 75, lines 14-16)

Based upon the foregoing, the fundamental point is that when OM&A expenditures in 2010 to 2012 are properly adjusted there is a $260M savings compared to the 2008 level of expenditures. The forecast savings are significant without the adjustments but the adjustments demonstrate that the savings effectively "absorb" escalation, 53rd week impacts and the impact of Pickering B Continued Operations/refurbishment. The cost savings and the cost discipline which OPG is imposing on Base OM&A are real. To use a simple example, if costs were $100 in year 1 and the costs in year 2 were $95 after removing escalation in wages and other atypical factors, then one could conclude that there has been a reduction in expenditures from previous levels. This is what the $260M represents over the 2010 to 2012 period compared to 2008.

Board staff also questions the use of 2008 as a comparator year (Board staff argument, pp. 48-49). In its zeal to make it seem as if OPG had selected this particular year to "cook the books," Board staff's submissions fail to mention OPG's evidence explaining why 2008 was used. Simply put, "that was the first year of regulation for OPG." (Tr. Vol. 4, p. 65)

Notwithstanding this evidence, Board staff persists in presenting a scenario that somehow OPG has used 2008 as a comparator just to make its performance look better. Board staff observes that compared to any other year, OPG would look unfavourable, i.e., 2007 or 2010 which were lower than 2008. With respect, this submission defies logic.

Although 2011 levels are less than 2007, 2012 levels are higher than 2007 by $14.5M. However, why would OPG use a year as a comparison for which regulation by the OEB did not apply? The levels of 2011 and 2012 are also higher than 2010. However, why would OPG use a budget (not actual) year as a comparator? It only makes sense that OPG should use an historical year as a comparator. In any event, the year-over-year cost change between 2010 and 2011 was clearly set out at Ex. F2-T2-S2. No party questioned the year-over-year cost changes from 2010 to 2012 or made submissions that they were unreasonable.

The only other historical year is 2009 and in that case, OPG's 2011 levels are less than 2009 and 2012 is only slightly higher than 2009. Clearly this is not a result that would have been favourable for Board staff's submission and its unfounded position.

Furthermore, based upon "two" data points, Board staff makes an unfounded assertion of a trend of OPG deferring costs to the test year. Board staff made this assertion notwithstanding that OPG witnesses made clear statements (as noted by Board staff in its argument) that they were not aware of any material deferral of costs to 2010. In light of this evidence, the assertion of Board staff about deferral of expenditures should be disregarded.

It is important to note that the factors giving rise to the changes in Base OM&A from 2007 through to 2012 were clearly set out in Ex. F2-T2-S2. In particular, those aspects giving rise to increases in 2010, 2011 and 2012 were also set out. No party disputed or challenged these variances or the basis of the increase and as such those increases should be considered as not opposed. Given OPG's efforts to decrease costs and find savings and on the basis of its evidence in support of its Base OM&A expenditures, the OEB should find that the Base OM&A expenditures for the test period are reasonable and should be approved as requested.

Board staff made various submissions related to OPG's evidence that an FTE reduction of 689 from 2008 levels was expected in 2012. In particular, Board staff stated that the reduction was over-stated and undertaking response J9.1 only provided insight into regular staff and not both regular and non-regular staff together for a total.

Board staff is incorrect. Ex. F2-T2-S1 Table 13 has always provided non-regular staff FTEs, so it's simply a question of adding them to the regular staff FTEs provided in this undertaking. Non-regular FTE reductions 2008-2012 remain at 559 as stated in pre-filed evidence; Regular FTE reductions are 643 as noted above. The following table sets out the combined regular and non-regular FTE levels:

Staff Summary - Nuclear Operations

Line No.	Group	2007 Actual	2008 Actual	2009 Actual	2010 Budget	2011 Plan	2012 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Regular Staff Headcount - J4.4**	7,281	7,348	7,332	7,100	6,769	6,662
2	**Regular Staff FTEs - J9.1**	7,270	7,302	7,297	7,155	6,808	6,659
3	**Non-Regular Staff FTEs (Ex. F2-2-1 Table 13)**	733	720	732	400	247	161
	Total Staff FTEs	8,003	8,022	8,029	7,555	7,055	6,820

Board staff took issue with OPG's statement in the undertaking response that the 2007-2009 FTE reflected a relatively imprecise measure of historic measure of FTEs. Future FTEs are precise forecasts derived from planned hours or work, taking into account differences between 35 and 40 hour per week employees. As indicated in J4.4, historic FTEs were calculated as the average of month-end head counts for a given year, which does not take into account different work-weeks or the ebb and flow of regular staff during the month. The historic FTE calculation is therefore inherently less precise than future FTE forecasts. As a result, OPG stands by its statement in respect of historic FTEs.

Undertaking J4.4 indicates FTE reductions 2008-2012 of 643 (6659 minus 7302 = 643) versus 443 as noted in the Board staff Submission. Given the approximate nature of the historic FTE calculations, OPG asserts that the restated FTE reduction of 643 is in fact not "much lower" than the 689 FTE reduction provided in pre-filed evidence.

Further discussion of the FTE forecast is provided in Section 5.3 Employment Levels and Reporting.

Another of Board staff's recommendations is that OPG make greater use of contractors for project-based outage work, on the basis that external resources are cheaper than internal ones (Board staff argument, p. 45). While Mr. Sequeira testified that the majority of companies who had decided, for a particular function, to employ outside contracts probably did so for cost-reduction reasons, he was never asked by Board staff whether OPG ought to adopt this approach (Tr. Vol. 3, p. 15).

Mr. Sequeira's testimony spoke about those companies who had decided, for a particular function, to rely on outside resources. It did not speak about those who did not. ScottMadden did not analyze the feasibility of outsourcing outage work, which would have required it to delve into the differences between OPG and its U.S. comparators in areas such as union representation. It would have had to look at case studies such as Bruce Power (which, it is submitted, is a close comparator to OPG in this regard), to see why it decided to discontinue an outsourcing arrangement with OPG in favour of repatriating outage-related IMS staff (G2-T1-S1, pp. 7-8). In short, a blanket suggestion that OPG blindly use more contractors for outage-related project work without further investigation is not well-founded.

SEC

SEC suggests a reduction of $40M per year to OPG's cost of service on the basis that OPG should be able to achieve in 2011 and 2012 a non-fuel cost metric of $25.10/MWh at Darlington (comparable to 2008 levels). SEC's assertion is without merit.

OPG's evidence at Ex. F2-T1-S1, Attachment 8 is that for 2011 the Darlington non fuel operating cost target is $26.52/MWH and for 2012 the target is $26.98/MWh. These same numbers are shown as OPG's targeted non fuel operating costs in OPG's response to L-12-026 and in the initial response of L-12-029. The response to L-12-026 indicated there would be need to be a $40M reduction in 2011 and $54M reduction in 2012 to maintain a $25.10/MWh non fuel operating cost target in 2011 and 2012. However L-12-029 was subsequently corrected, in order to revise the non fuel operating costs target for 2011 and 2012. The $26.52/MWh and $26.98/MWh non fuel operating costs included OPEB, whereas the 2008 non fuel operating actual do not include OPEB (L-12-029 corrected). L-12-026 was unfortunately not updated for the corrected values. The correct non fuel operating costs which OPG is projecting for 2011 and 2012, as shown in L-12-029 are $25.02/MWh and $25.43/MWh which are very comparable to the three year average actual of $25.10/MWh achieved in 2008. Thus SEC's suggestion for a $40M reduction is without merit.

SEC argues for a disallowance of $10M to reflect what it states is a historical overestimation of the labour price variance account (SEC argument, para. 6.3.5). OPG opposes the proposed disallowance because it is not consistent with the evidence put forward in the hearing. Mr. Mauti, who is personally involved in the calculation of the labour rates involved, has stated that there is neither a "fudge factor" build into the estimates, nor is there any bias one way or the other in developing the estimates:

> MR. MAUTI: The two years that you've referenced, they are lower. I do remember years in the past where there's been slight variances that have been higher, where it ends up being in a deficit position, not a credit position. You know, through extracting the data from our HR system, we look at prior years, amount of costs within those job families. We add onto that known escalation factors, such as cost of living allowance, or whatnot. We update the burden rates that were used and calculate it on a regular basis, and add that onto the standard labour rate.
>
> So we do the best we can on, again, roughly, in nuclear's case, the billion dollars' worth of costs that we have flowing through labour, and then try to determine our appropriate standard rate. And I believe anybody that does a standard labour costing process will never be at par. There will always be a variance.
>
> We think that the amounts that we're off in the years in question, within about 1 percent is a fairly reasonable process for estimation.
>
> I don't think it's necessarily biased one way or the other (Tr. Vol. 5, pp. 54-55).
>
> MR. MAUTI: I don't think either are. You know, I'm involved personally in the calculation of the labour rates and the review. There is no fudge factor or contingency that's built into them (Tr. Vol. 5, p. 56).

AMPCO

AMPCO submits that the OEB should reduce Pickering A's Base OM&A by 10 per cent which would represent a reduction of $17.3M in 2011 and $17.1M in 2012.

As a result of the last rate order, OPG adopted a "much more aggressive business planning cost reduction process" than that which underpinned its previous application

(Tr. Vol. 4, p. 14, lines 5-7). Pickering A Base OM&A in 2012 ($170.6M in 2012, Ex. F2-T2-S1, Table 1) is below 2008 actual costs ($187.6M, Ex. F2-T2-S1, Table 1) by $17M (9.1 per cent), after absorbing cost pressures of $15M due to escalation and the impact of the 53rd week in 2012 (Ex. F2-T2-S1, Table 3). As part of OPG's gap-based business planning, the lessons learned are being implemented at Pickering A.

The submission of AMPCO has no basis and is arbitrary. The OEB's decision in EB-2007-0905 was in respect of OPG's benchmarking of Pickering A's production unit energy cost ("PUEC"). As is clearly indicated in this current proceeding, as part of its benchmarking and gap-based business planning process, OPG has established aggressive targets at Pickering A in respect of its operation and maintenance costs.

CME

CME argues that the $85 million reduction (including $40 million attributable to Nuclear) represents a material misstatement of savings by OPG (CME argument, paras. 55-57). OPG disagrees with this characterization. The stated savings represent plan-over-plan savings in 2010 comparing OPG's 2009-2013 business plan with its 2010-2014 business plan (Tr. Vol. 10, pp. 2-6).

When the OPG Board of Directors approves the business plan, it is approving a one year budget for the first year and a multi-year financial and operational "planning reference" for the future years. When the business plan is updated, the ability of plan-over-plan comparisons to isolate impacts of myriad changes in planning inputs and assumptions provides valuable insights into identifying key drivers of operational and financial performance. Such analysis enhances management's accountability for performance improvement by making achievement more transparent. It also enables identification of the impacts of significant factors over a multi-year planning horizon.

OPG agrees that its identified cost savings represent changes from previously planned levels – but maintains it has never – materially or not – mislead or misstated these savings. Plan-over plan comparisons are an integral component of the business planning process, both for OPG's management and its Board of Directors, as can be seen in the Nuclear Business Plan presented to OPG's Board (Ex. F2-T1-S1 Attachment

1, pp. 9, 16, 17 and 19). OPG has always characterized these reductions as changes from previous expectations.

OPG agrees that actual year-over-year analyses are also useful and can best illustrate absolute actual trends. OPG undertakes year-over-year analyses both during its business planning process and in its analyses of actual year-end results.

4.2.2 Nuclear Project OM&A

No party objected to OPG's forecast of Nuclear Project OM&A. As such, and for all the reasons set out in its evidence and AIC, these amounts should be accepted by the OEB as filed.

4.2.3 Nuclear Outage OM&A

No party objected to OPG's forecast of Nuclear Outage OM&A. As such, and for all the reasons set out in its evidence and AIC, these amounts should be accepted by the OEB as filed.

4.3 PICKERING B CONTINUED OPERATIONS

Issue 6.7 – Are the proposed expenditures related to continued operations at Pickering B appropriate?

In respect of OPG's proposal for Pickering B Continued Operations, OPG provided a comprehensive business case that explored a number of sensitivities and acknowledged risks, together with mitigation strategies for those risks. Its analysis established a $1.1 billion Net Present Value ("NPV") and reflects a prudent approach that supports the proposed expenditures (Ex. F2-T2-S3 Attachment 1).

Pickering B Continued Operations is important to Ontario's future electricity supply. The initiative will increase the output of Pickering B through the extension of its operating life, impact the future operations of Pickering A, as OPG does not plan to operate the two units at Pickering A with a Pickering B shutdown (Tr. Vol. 4, p. 44), and supply baseload generation during the first part of the period when the refurbishment outages for the Darlington units are planned. Continued Operations is supported by the Government of Ontario (Ex. D2-T2-S1 Attachment 3) and is also a fundamental element of the Long

Term Energy Plan and Draft Supply Mix Directive (K16.2, K16.3). The OPA conducted an assessment of the integrated power system impact of Pickering Continued Operations and supports OPG's proposed test period expenditures based on the potential for substantial system benefits (Ex. F2-T2-S3 Attachment 2).

Commencing the initiative in the test period is critical to delivery of the benefits. If the incremental work is not undertaken in the test period, the units will start to close in 2014 and benefits arising from the Continued Operations of Pickering B will be lost (L-01-072; Tr. Vol. 4, p. 50).

> MR. STEPHENSON: And am I right that if you don't do this work during the test period - that is, by 2012 - then the decision is made for you? You are not doing it at all, and these units are going to start closing in 2014. That's the bottom line?
>
> MR. PASQUET: That's the bottom line.

Board staff (p. 59) presents the primary arguments with respect to Pickering B Continued Operations. Notwithstanding the comprehensive nature of the OPG business case and the underlying economic model, the significantly positive results (an NPV of $1.1 billion) and the importance of the initiative to the Province, Board staff does not support it. In particular, Board staff wrongly suggests that the initiative be deferred. No party provides a competing analysis or raises propositions that place the reasonableness of the timing or cost of the initiative in doubt. As stated above, in order to achieve the benefits of the initiative, the work identified in the business case for 2011 and 2012 must begin as planned. As a result, it is OPG's submission that any suggestion that the initiative be deferred should be rejected by the OEB.

With respect to Board staff's criticism of the OPA's assessment of the initiative, OPG submits that Board staff is ignoring key aspects of the evidence. The OPA received all of the quantitative assumptions underpinning the business case (Ex. F2-T2-S3, Attachment 2, p. 4). This permitted the OPA to be free to carry out its analysis as it, and not OPG, saw fit. The OPA understood the risks as reflected by the fact that the OPA identified that the economic results were impacted by gas prices, carbon prices, the amount of gas-fired generation and the availability of imports (Ex. F2-T2-S3 Attachment 2, p.2). Based on the application of their expertise in conducting system analysis, the OPA presented and qualified their conclusions appropriately. Contrary to the assertion by Board staff, the OPA's opinion was fully informed.

Board staff presents selective excerpts from the OPA's letter stating that "the OPA's support is quite qualified" (Board staff argument, p. 63). On any plain reading of the OPA's letter, it is clear that the OPA supports the proposed test period expenditures, notwithstanding their acknowledgement of the risks:

> Based on the potential for substantial system benefits, the OPA supports a decision by OPG to proceed with an initial expenditure of funds in the period 2010-2012 to assess the feasibility of continued operation of Pickering NGS, and to maintain the option for continued operation should it prove to be feasible. System benefits should be re-assessed before committing additional funds required beyond 2012. (Ex. F2-T2-S3 Attachment 2, p. 2)

Board staff is incorrect in asserting that total generation cost ("TGC") instead of the OPA's electricity price of $50/MWh should be used for the economic analysis. The OPA considered the incremental cost of the initiative divided by the incremental output. This appropriately reflects a comparison to the cost of electricity of a new gas fired generation facility being put in place to replace Pickering B if its life were not extended. It is an "apples-to-apples" comparison. The Board staff's suggestion of using TGC should be rejected since TGC includes costs that exist notwithstanding the shutdown of Pickering B and is not a proper basis to complete a comparison to an alternative generation facility.

Board staff also incorrectly asserts that the benefit of $1.1 billion NPV in OPG's business case is overstated. Board staff focuses on two aspects - the unit capability factor ("UCF") and the price of natural gas. With respect to UCF, it is important to note that OPG performed a sensitivity analysis with varying levels of UCF (Ex. F2-T2-S3 Attachment 1 p. 9). OPG's net present value sensitivity analysis provided in its business case demonstrates that the NPV is significantly positive even for the lower end of the range displayed for average capability factor. OPG also notes that it seems inconsistent for Board staff to take the position that OPG is overly optimistic in its UCF assumptions for Pickering B Continued Operations, yet at the same time argue that its nuclear production forecast is too low (Board staff argument, page 87) and its Forced Loss Rate target for

Darlington is too high (Board staff argument, page 44). This inconsistency implies that Board staff has not applied any degree of rigor in its assessment of either OPG's production forecast or its UCF forecasts.

With respect to natural gas pricing, at page 64 of their submissions, Board staff makes reference to their Technical Conference question related to the reasonableness of the gas forecast used in OPG's NPV analysis. However, in making submissions Board staff fails to set out OPG's response to the Technical Conference question. At the Technical Conference OPG stated that "The range of gas prices that were analyzed were anything between, in US dollars, 4-dollar gas to 10-dollar gas, and in both cases they yielded a positive net present value" (Technical Conference Tr., p. 57).

No party in their submissions raised substantive criticism of OPG's NPV analysis. The NPV analysis is correct and the proposed expenditures for the test period are reasonable.

Board staff includes a discussion of the error in OPG's pre-filed evidence which double-counted a portion of the Fuel Channel Life Cycle Management project costs (Board staff argument, p. 59). As noted during the hearing and in its AIC (Tr. Vol. 5, p. 4, OPG AIC, p. 98), OPG will adjust the payment amount calculation in the draft Payment Amounts Order to correct for this double counting.

In addition to Board staff, CCC (p. 25) and SEC (paras. 6.7.1 - 6.7.2) offer additional arguments on Continued Operations. CCC and SEC each feel that it is premature for the OEB to approve Continued Operations at this time (with CCC calling for finalization of the IPSP and SEC calling for an independent review prior to OEB approval). Both of these arguments ignore the evidence that in order to preserve the option of continuing to operate Pickering after 2014, OPG will need to conduct the work proposed in the test period or the option will be lost (Tr. Vol. 4, pp. 118-119, L-01-072)). Furthermore, OPG has already sought and obtained from the OPA an independent assessment of the economics of the initiative, the results of which were supportive.

SEC further states that OPG should not receive funding for Continued Operations until it "is ready to commit to completing the project" (SEC argument, para. 6.7.2). In order to get to the point where the life of Pickering can be extended beyond 2014, funds must be spent during the test period for OPG to satisfy itself and its regulator that the plant is fit for service until 2020 (Ex. F2-T2-S3 p. 9). It is unclear what SEC seeks in terms of commitment to the initiative from OPG. OPG has committed to the initiative and its operational plans reflect this fact. OPG is simply being prudent by planning to reassess the path forward as additional information becomes available. OPG is subject to CNSC regulation and must demonstrate to the CNSC that the facility will continue to be fit for service until at least 2018-2020 before it can definitively state that it will achieve the incremental production in the business case.

Energy Probe (para. 110) states that it would prefer to see the initiative funded by a private shareholder, acknowledges that this not a possibility and provides no further submissions. In OPG's submission, no reply is warranted to this argument.

OPG addresses submissions related to the Pickering B Continued Operations costs in the Capacity Refurbishment Variance Account in Section 11.3 Capacity Refurbishment Variance Account.

4.4 FUEL COSTS

Issue 6.6: Is the forecast of nuclear fuel costs appropriate?

Introduction

Board staff and a number of other parties (AMPCO, CME, CCC, SEC and VECC) criticize OPG's nuclear fuel procurement practices and suggest that the existence of the Nuclear Fuel Variance Account has reduced OPG's incentive to seek ways to lower its fuel costs. For the reasons that follow, OPG submits that none of these criticisms have merit. Benchmarking demonstrates that OPG's 3-year fuel cost per MWh is lower than any other nuclear operator in the comparator group, which includes Bruce Power (Ex. F5-T1-S1, page 133).

The nuclear fuel procurement strategy that OPG follows is appropriate. Its use has been validated by external experts (J4.11). The current strategy predates regulation, so to argue that OPG has been influenced by the creation of the Nuclear Fuel Variance

Account is both illogical and untrue. This strategy was reviewed and found to be reasonable by the OEB in the last payment proceedings. OPG submits that the only thing that has changed between then and now is that parties, with the benefit of hindsight, can construct other strategies that might have lowered costs given the way uranium prices have moved over the last few years.

Parties also express dissatisfaction with the operation of the Nuclear Fuel Variance Account. Board staff claims that it places undue risk on ratepayers and provides opportunities for OPG to benefit financially. To remedy this, they offer a one-sided "risk sharing" proposal under which, the entire risk for any under-forecasting falls on OPG, but the impacts of over-forecasting are split equally between the company and ratepayers. Even intervenors are leery of Board staff's proposal, pointing out that its adoption may itself provide an incentive to over-forecast nuclear fuel costs (VECC argument, para. 48).

In making this proposal, Board staff ignores the fact that the main driver of variances in actual to forecast fuel costs is that actual nuclear production has been lower than forecast for the last several years (L-12-33). If Board staff were truly interested in improving the accuracy of the nuclear fuel forecast they would support OPG's proposed nuclear production forecast, but they do not. Board staff's submission that the impact of nuclear fuel on working capital creates an incentive to over-forecast fuel cost has no basis. There is no evidence on the record that OPG's fuel price forecast is biased to over-recovery. On the contrary, OPG's evidence clearly establishes that the forecast is unbiased.

The Nuclear Fuel Procurement Strategy Previously Approved by the OEB Continues in Effect and Remains Reasonable

Attempts to Review OPG's Nuclear Fuel Procurement Based on Hindsight Are Inappropriate and Should Be Rejected

It is clear from the parties' submissions that they are intent on measuring the prudence of OPG's nuclear fuel procurement strategy with the benefit of hindsight. Based on the way uranium prices have moved over the last few years, they argue that other strategies might have produced lower cost. No party, however, has offered any evidence to show that these strategies would have been seen as superior based on information that was known or could have reasonably been known in 2006 and 2007 when OPG entered into the contracts that these parties now question. Over the course of many proceedings, the OEB has rejected this approach to reviewing prudence as inappropriate (RP-2001-0032, pages 62-63). A similar finding is warranted here.

In EB-2007-0905 the OEB reviewed OPG's fuel procurement strategy and found:

> The Board accepts that uranium costs and fuel prices are highly volatile and OPG has developed a reasonable strategy to manage this risk through a supply portfolio consisting of both market and fixed-price contracts. (EB-2007-0905, page 33).

While Board Staff, CME, and SEC are all highly critical of OPG today, OPG's fuel procurement strategy was in evidence in its last payment amounts case (EB-2007-0905, Ex. F2-T5-S1), OPG's contracting activities in the 2006-2007 timeframe were presented in the last case (EB-2007-0905, Ex. F2-T5-S1, pages 4-5). The evidence in the last case also discussed OPG's views on price and supply availability (EB-2007-0905, Ex. F2-T5-S1, pages 6-8). These views, as discussed below, are very much consistent with the analyses OPG received from external experts around the time last case was being developed (J5.10, Attachments 1-3).

A re-read of the submissions by Board staff, CCC, CME, SEC and VECC on fuel costs and the Nuclear Fuel Costs Variance Account from the last case reveals, not surprisingly, that at that time all of these parties lacked the insights on the appropriate mix of fuel contracts that they now claim. This is further evidence that their current positions are based on hindsight and should be disregarded. None of these parties opposed the creation of the Nuclear Fuel Cost Variance Account with Board staff stating: "However, if there is uncertainty in the price forecast, the use of a variance account can eliminate the risk." (Board staff argument, EB-2007-0905, page 41).

There is No Basis on Which to Conclude that OPG's Nuclear Fuel Procurement Strategy Is Deficient or that Another Strategy Would be Superior Over the Long-term

Board staff and CME imply that given the increases in OPG's nuclear fuel costs, the Nuclear Fuel Procurement Strategy must be deficient (Board Staff argument p.53; CME argument, para.146). OPG submits that there is no evidence on which to conclude that another strategy would yield better results over the long term.

In any event, however, the purpose of a strategy is to guide the future, when supply conditions and the direction and speed of price movements are only forecast. Furthermore, a strategy must work in a variety of market conditions to assure an adequate supply of nuclear fuel. In these circumstances, OPG submits that its strategy is appropriate and, as fully discussed below, external review confirms this view.

OPG agrees that nuclear fuel costs have increased, but urges the Board to view this increase in the context of the overall movement in uranium prices and the increases in nuclear production. OPG's chart on historical uranium market prices shows that spot prices jumped from $20 US/lb U308 in 2004 to over $130 US/lb U308 in 2007 (a 550 per cent increase) and long term market prices jumped from $20 Us/lb U308 in 2004 to peak to about $95 US/lb U308 (a 375 per cent increase) (Ex. F2-T5-S1 page 7). Although prices have declined from their peaks, they still remain substantially above the levels seen prior to 2005 (*Id.)* OPG is not immune from uranium market forces, and therefore an increase in nuclear fuel costs is to be expected.

CME and other intervenors have not seriously challenged OPGs extensive evidence on the causes of what OPG described in its evidence as the "disconnect" between 2011 and 2012 forecast nuclear fuel costs and the trend in uranium market prices (spot and term) (Ex. F2-5-1 pp. 8-10). These causes include the lagged effect of past contracts entering into fuel prices and the use of average cost accounting. Board staff notes the factors cited by OPG in its submission, and then proceeds to ignore them. SEC comments favourably on the smoothing effect of average cost accounting (SEC Argument, para.6.6.3), and "VECC accepts that current fuel prices include the lagged effects of prior purchases and also of the average inventory accounting procedures used to calculate current costs." As such, "VECC cannot conclude conclusively that there are significant defects in the procurement strategy" (VECC Argument, paras. 42-43).

The key drivers impacting fuel costs are generation, (i.e., the quantity of fuel required), price (i.e., for raw uranium, conversion services and manufactured fuel bundles) and fuel efficiency (Ex. F2-T5-S1 p.10; Ex. L-12-033). A very significant factor in the increase in fuel costs from 2007 to 2012 is that OPG's actual generation in 2007 was 44.0 TWh, while its 2012 generation is projected to be 50 TWh, which is about a 14 per cent increase (Ex. E2-1-2 Table 1). Some increase in uranium fuel costs can also be ascribed to increased costs for contracted conversion services and manufacturing fuel bundles costs (F2-T5-S1, pages 4-5). Given these facts, there is no basis on which to conclude, as parties urge the OEB to do, that increase in nuclear fuel costs reveals a deficiency in OPG's nuclear fuel procurement strategy.

Board staff criticizes OPG for having entered into long-term contracts in 2006 and 2007. In Board staff's view the fact that OPG signed these contracts indicates that OPG is overly concerned with security of supply and not sufficiently concerned with price (Board staff Argument, page 54). OPG has two responses. First, it is easy to say now, when uranium supply is relatively abundant and prices have come down, that OPG was overly concerned with assuring adequate supply in 2006 and 2007. OPG expects parties would argue exactly the opposite, however, if it had not secured adequate supply when needed and prices had continued to rise. As Mr. Mauti explained:

> Now, again, with the benefit of hindsight, would we have negotiated any fixed-price contracts in 2006-2007? Knowing what we know now, likely not.
>
> But at the period of time we were doing the negotiation, we had seen tremendous volatility in uranium contracts. We did not necessarily want to leave ourselves exposed to what the future of that market would be.
>
> So we felt there was some value of locking in some indexed contracts at that point (Tr. Vol. 4, page 111)

Second, OPG has provided contemporaneous external reports that describe the anticipated supply and contracting environment that existed at the time OPG was contracting for additional uranium (J5.10, Attachments 1-3). These reports demonstrate that OPG's was not alone in its concerns about rising prices and supply availability and its contracting activity was consistent with that of other utilities at the time. (J5.10, Attachments 1 and 2).

OPG's nuclear procurement strategy was independently reviewed by UxC Consulting (J4.11, Attachment 2). Any fair reading of this review leads to only one conclusion – UxC found OPG's fuel procurement strategy to be appropriate. The review contains some recommendations for the company to consider. With respect to these recommendations, Board Staff claims that OPG has not implemented all of them (Staff Argument, page 53). Board staff is wrong. OPG has provided evidence that details each UxC recommendation and shows how it was addressed (J4.11, pages 2 and 3). Responsive actions included changes to its procurement policy. (*Id*.)

Board staff also questions the relevance of the UxC report and notes that it pre-dates OEB regulation (Board staff argument, page 53). OPG is hard pressed think of what could be more relevant to the determination of the reasonableness of its procurement strategy than a contemporaneous review by external experts. The fact that it predates OEB regulation is not surprising since the strategy itself predates the OEB assuming jurisdiction over OPG.[19]

With respect to OPG's fuel procurement strategy going forward, Board Staff argues that OPG's strategy needs to be more balanced with greater emphasis on "minimizing fuel costs." Board Staff questions the prudence of contracting for three to four years of supply within one year, when only two years of supply is required as stated by OPG (Ibid., p.55).

As discussed above and confirmed by the UxC Review and other external documents that OPG has provided, the contracts executed in 2006-2007 were entered into in an unprecedented environment of rising market prices and difficult market conditions. (Ex. J4.11, Attachment 2, p 9-17; J5.10, Attachments 1-3). OPG's strategy of entering term contracts at that time was similar to that of other nuclear utilities (Ex. J4.11, Attachment 2, p.10). Going forward, OPG continues to assess the balance of market-based, indexed contracts, and spot market purchases and adjust them as conditions warrant (Technical Conference Tr., p.54; J4.11 and attachments).

[19] Much has been made by Board Staff and CME that when Mr. Mauti testified, he indicated he was not aware of such a study being done (Board Staff argument, page 54; CME argument para. 153). Mr. Mauti's Curriculum Vitae (Ex. A1-T9-S1) shows that he is the Director of Nuclear Reporting. His responsibilities are related to accounting for the cost of nuclear fuel and not its procurement. CME's characterization of Mr. Mauti as being "in charge of nuclear fuel purchases" is wrong. Board staff also ignores Mr. Mauti's response to an earlier question, where he clearly indicated that he wasn't "personally" aware of any independent reviews comparing the impacts of market-based and indexed contracts, so as to make clear that such reviews may exist, but he didn't know of any (Tr. Vol. 4, p.114). Instead, Board Staff offers the bizarre observation that Mr. Mauti might have been unaware of the UxC Review "due to the fact that OPG has the variance account which allows them to pass all cost increases on to consumers." (Board Staff argument, p. 55).

Board Staff's premise appears to be that OPG should be entering the market on a more regular basis as a means to "minimize fuel costs." There is no evidence, however, to indicate that such a strategy will result in lower fuel costs. Indeed, OPG would submit that it is not the frequency of entering the market but the nature of the pricing provisions (for example, indexed versus market contracts) that will establish fuel costs.

The OEB should take note that OPG has the lowest fuel cost per megawatt hour of any utility according to the 3 Year Fuel Cost per MWh benchmark in the ScottMadden report (Ex. F5-1-S1, page 133; Tr. Vol.5, p.109). This comparison includes Bruce Power (Ex. F5-1-S1, page 156, Table 11 – EUCG Panel).

OPG's fuel procurement strategy seeks to minimize price risk/volatility by purchasing both indexed and market price contracts. OPG's evidence is that its current portfolio is a combination of fixed and indexed contracts with approximately 27 per cent of the total procured through indexed contracts in 2012 (Ex. F2-T5-S1, page 6, Chart 2). By adopting this strategy to manage price risk, OPG will not achieve the lowest price when market prices decline, but on the other hand, when market prices increase by 550 per cent as occurred in 2007 and 2008, the presence of indexed contracts will help insulate ratepayers from these higher market prices.

OPG's fuel procurement strategy is achieving its objectives. The evidence is that OPG's strategy of using indexed contracts resulted in a significant cost savings in 2008 compared to a strategy of using spot contracts (Ex.J4.8). In 2009, OPG's analysis indicates that the strategy resulted in a breakeven between indexed and long-term market contracts and that cost savings would have arisen if OPG had been able to acquire the supply on the spot market (Ex.J4.8). However, this analysis does not include any assessment of the increased supply risk of relying solely on spot market purchases. In Ex.J4.9, OPG provides a comparison of average actual and forecast prices under index and market contracts from 2004 onward. It shows that the price paid under indexed contracts has been both below and above prices paid pursuant to market priced contracts.

CME and SEC claim that OPG can move to 100 per cent market-based contracts because finding suppliers to enter into long term market based contracts is not a problem for OPG (CME Argument, page 41; SEC Argument, para.6.6.6) This claim is based on testimony that when OPG last secured contracts in 2006-2007, it did not have any difficulty in finding companies willing to enter into long-term market-based contracts. However, OPG's witness also testified that he does not have any knowledge of whether that situation has changed today (Tr. Vol. 4, page 141).

OPG submits that there is no basis on which to conclude that a 100 per cent market-based contract strategy is executable. The uranium market is relatively thin with a limited number of suppliers and it is not always possible to secure uranium supplies on the spot market (Tr. Vol. 4, p.177; Vol. 5, p.78). Additionally, OPG refers the to the Ux Consulting, "Uranium Market Outlook" October 2005 (Ex. J5.10, Att. 1, pp. ii and v – a confidential document), which sets out some of the challenges facing utilities in 2006 seeking to contract for new supply, particularly the minimum duration periods of contracts that producers were willing to execute.

OPG's procurement strategy, which the OEB reviewed and approved in the last application, has not changed because neither OPG's internal nor external assessments have supplied any basis for change. None of these reviews have suggested an approach that would be superior over the long-term to the fuel procurement strategy OPG is currently following. OPG's strategy going forward is reviewed annually (Tr. Vol. 4, p.146) and will continue to include balanced mix of market-priced and indexed contracts to reduce volatility (Tr. Vol. 3, pages 112-113).

Proposals for Additional External Review and Studies

CCC and VECC submit that OPG should be required to obtain a third-party assessment of its nuclear procurement strategy and submit it as part of the next hearing (CCC Argument, para. 123; VECC Argument para. 43). CCC proposes that as part of this exercise, the consultant should assess the comparative value of indexed contracts and market contracts. In contrast, SEC, wants OPG to develop a plan to change to a market-based uranium procurement program and quantify the savings that can be achieved (SEC Argument, para. 6.6.5).

CCC and VECC submit that there be an independent review of OPG's nuclear fuel procurement strategy. OPG notes that an independent review was done in March 2008. OPG continues to believe that its current nuclear fuel procurement strategy is appropriate as the prior review found, however, OPG is willing to undertake another review, so long as the funding for this and other studies is maintained in the Regulatory Affairs budget.

With respect to SEC's proposal that OPG be required to develop a plan to switch to a 100 per cent market-based uranium procurement program and develop a plan to quantify the savings that can be achieved, OPG submits that the use of the portfolio approach is consistent with industry practice as set out in the UxC Report at J4.11, Att.1. Furthermore, as shown in Ex.J4.8, OPG's procurement strategy of using a combination of indexed and market contracts has reduced price volatility.

The Existence of the Nuclear Fuel Variance Account Has Had No Impact on OPG's Fuel Procurement Strategy

Board staff and others have speculated that the existence of the Nuclear Fuel Variance Account has diminished OPG's focus on controlling nuclear fuel costs (Board staff argument, page 54; VECC argument, para. 44). Not surprisingly, they offer no evidence to support this conjecture. As noted above, OPG's nuclear fuel procurement strategy predates the existence of the variance account. This strategy, previously approved by the OEB, has clearly articulated goals, among which is minimizing cost (Ex. F2-T5-S1, p. 1). Board staff and other parties have not identified a single action to lower fuel costs that OPG could have taken, but did not because of the variance account.

As discussed above, the sources of increase in the test period nuclear fuel cost forecast are increases in the price of uranium, conversion and assembly price increases, and increased nuclear production compared to the previous test period. The test period increase is largely due to the increasing importance of contracts signed in 2006-2007. These contracts were signed well before the start of OEB regulation. Clearly, the possibility of a variance account was not even contemplated when these contracts were signed. As far as nuclear production goes, even the most cursory reading of OPG's production forecast evidence would defeat a suggestion that the company is over-forecasting nuclear production to artificially raise the test period nuclear fuel cost forecast.

The Recommended Changes to the Variance Account Are Unnecessary and Should be Rejected

Board Staff, SEC, CCC, AMPCO and CME submit that the Nuclear Fuel Cost Variance Account should be restructured to have an asymmetrical cost "sharing" component and to capture the effects of the variances related to the cost of capital associated with fuel inventory in working capital. Specifically, Board Staff argues for a 50/50 "sharing" of variances if actual costs are above OPG's forecast, but if the actual costs are below the forecast, 100 per cent of the variance is returned to consumers. VECC calls the mechanism put forward by Board Staff an "imaginative proposal," but notes its potentially punitive nature and urges further analysis be done prior to OEB approval of any such proposal in order to avoid unintended consequences, which in VECC's view could include the creation of an incentive to over-forecast nuclear fuel costs (VECC Argument, para. 48).

Any forecast, except by sheer coincidence, will be wrong. Contrary to Board staff's submissions, the variance account removes any incentive to over-forecast nuclear fuel cost by removing the prospect of any benefit from such an over-forecast. In this way, OPG recovers only its actual fuel costs and ratepayers are never charged more than OPG's actual cost. Under Board Staff's proposal, however, unless it consistently forecasts high, OPG can only be a loser, never a winner. Any incentive for OPG to over-forecast nuclear fuel costs, however, will be counterbalanced by the incentive for intervenors to advocate as low a forecast as possible because if actual costs are higher than forecast, ratepayer pay half the difference between forecast and actual.

Implementation of staff's "sharing" proposal would result in a significant increase in business risk to OPG by removing any reasonable prospect of actually recovering its nuclear fuel costs over the long term. Such a proposal is obviously contrary to the creation of just and reasonable rates, clearly biased and was raised for the first time in Board staff's argument and therefore OPG's witnesses were not able to address it.

Board Staff says OPG's nuclear fuel inventory is overstated because OPG has consistently over-forecast its fuel costs and suggests that this is due to an unintended incentive created by the structure of the variance account.[20] As explained above, the predominant source of the alleged "over-forecast" is that actual nuclear production has been below forecast in every year since regulation began. The way to address this issue is not to introduce an arbitrary and one-sided "sharing" proposal, but rather to adopt the more accurate production forecast that OPG has proposed and Board staff has opposed.

A number of intervenors have made submissions that indicate a concern that OPG's rate base is overstated because the nuclear fuel forecast impacts working capital and that the resulting earnings are not captured in the Nuclear Fuel Cost Variance Account (Board Staff argument, page 57, VECC argument, para. 35; AMPCO argument, para. 190). These intervenors support Board Staff's proposal to modify the existing variance account to account for impacts on working capital. VECC agrees that this issue warrants attention, but expresses a preference to establish a new account to address the impact of variances on rate base rather than modifying the existing account.

OPG submits that using the existing variance account, or creating a new one, to address perceived over-recovery due to the impact of nuclear fuel inventory in rate base is an extremely complex task to do accurately (Tr. Vol. 15, page 26). Given that variations in rate base have rarely, if ever, been addressed through variance accounts it makes little sense to do so here where the amounts involved are likely to be relatively small and well short of the OEB's materiality threshold (*Id.)*.

Board staff indicates in their submission that under OPG's definition of prudence, there could never be hindsight review and therefore no disallowance (Board staff argument, p. 56). In its evidence, OPG never implied or suggested that there would be no potential disallowance of fuel costs after the fact. What OPG said, and what the OEB has said many times before, is that disallowances must be based on a finding of imprudence that

[20] Board Staff cites the question in SEC Interrogatory No. 33 for the proposition that that OPG has over-forecast its nuclear fuel costs by 7-15% over the period 2007 – 2009, but fails to mention that in the answer OPG disagrees with SEC that there is a systemic bias in the forecasting of fuel costs (Staff Argument, p.58). OPG's evidence shows that there are instances where actual nuclear fuel cost on a per unit basis is both higher and lower than forecast over the three years in question (Ex. F2-T5-S2, pages 2-3).

rests on information that was or reasonably should have been known at the time the decision was undertaken. Contrary to Board staff's submissions, OPG's testimony stated that prudence reviews represent an important component of the regulatory process (Tr. Vol. 15, p. 126).

For the reasons set out above, the Nuclear Fuel Costs Variance Account should not be re-structured. The claimed forecasting bias does not exist and the proposed cost sharing mechanism is highly unfair and creates perverse incentives. As Mr. Barrett testified, there are already three things which drive OPG to prudent management of nuclear fuel costs: the OPG business planning process, a very experienced fuel procurement group who considers costs as part of its strategy and regulation by the OEB (Tr. Vol. 15, p.60).

4.5 OTHER REVENUES

Issue 7.2 - Are the proposed test period nuclear business non-energy revenues appropriate?

OPG disagrees with SEC, supported by VECC, who propose that net revenues from the sales of any surplus heavy water be applied as an offset to OPG's 2011 and 2012 revenue requirement.

SEC argues that, in order to ignore the net proceeds of the sale of surplus heavy water for purposes of setting rates, it is not enough that the heavy water is not, and has not been, in rate base since the advent of regulation in 2005. In SEC's view, reliance on this one principle would produce the illogical result that depreciated assets—even those such as trucks or office equipment that continue to be used in support of the regulated business—could be sold by OPG, with the proceeds retained by the shareholder.

This misconstrues OPG's position by seizing on only one aspect of the argument, albeit an aspect which supports exclusion of revenues associated with these assets. A further important characteristic of surplus heavy water is that it is ***surplus***, and by definition, not required to support the regulated operations, either now or in future (Ex. G2-T1-S1, p. 3). Exclusion of the revenues causes no harm to ratepayers. The exclusion of costs of storing and maintaining the asset from the nuclear revenue requirement also supports OPG's position (Ex. L-01-125).

SEC also points to the fact that Ontario's electricity ratepayers were required to pay for the surplus heavy water and as such deserve to benefit from its sale. But the Supreme Court of Canada has already considered this very question in similar circumstances and found as follows:

> Thus, can it be said, as alleged by the City, that the customers have a property interest in the utility? Absolutely not: that cannot be so, as it would mean that fundamental principles of corporate law would be distorted. Through the rates, the customers pay an amount for the regulated service that equals the cost of the service and the necessary resources. They do not by their payment implicitly purchase the asset from the utility's investors. The payment does not incorporate acquiring ownership or control of the utility's assets. The ratepayer covers the cost of using the service, not the holding cost of the assets themselves.[21]

As such, whether ratepayers did or did not pay for the surplus heavy water is irrelevant. SEC, at the hearing, indicated that in argument it would try to disaggregate from the debt retirement charge ("DRC") amounts attributable to surplus heavy water. Its view was that it would be unfair for OPG to retain the proceeds of surplus heavy water sales while the consumer continued to pay for these assets through the DRC (Tr. Vol. 10, p.120). No such calculation was presented by SEC, which is not surprising considering OPG's evidence that such a calculation was neither possible nor meaningful (J10.6), and the SCC's decision in ATCO, above.

Lastly, SEC objects that the treatment proposed in this instance differs from the approach proposed at the last hearing. At the last hearing, however, OPG did signal that it would be putting forward a proposal for the treatment of other nuclear revenues that differed from how these were treated in setting interim rates.[22]

OPG's proposal to modify past treatment of these revenues does not prejudice ratepayers, it is consistent with regulatory and judicial precedent, and for the reasons set out in Ex. G2-1-1 and OPG's AIC (pp. 31-32), it should be accepted.

---

[21] ATCO Gas and Pipelines Ltd. V. Alberta (Energy and Utilities Board), 2006 SCC 4, para. 68

[22] EB-2007-0905, p. 11: "While OPG is proposing in its first cost of services application the continuation of the methodology established for setting the interim payment amount, OPG believes that in a future proceeding there may be merit in pursuing alternative regulatory treatment for nuclear non-energy revenues, including consideration of some form of incentive profit sharing mechanisms."

4.6 PROJECTS

Issue 4.4: Do the costs associated with the nuclear projects, that are subject to section 6(2)4 and 6(2)4.1 of O. Reg. 53/05 and proposed for recovery, meet the requirements of that section?

Issue 4.5: Are the capital budgets and/or financial commitments for 2011 and 2012 for the nuclear business appropriate and supported by business cases?

Issue 4.6: Are the proposed in-service additions for nuclear projects appropriate?

Issue 4.7: Is the proposed treatment for Pickering Units 2 and 3 isolation project costs appropriate?

This section responds to a number of proposals by Board staff that propose reductions to OPG's rate base (Board staff argument, pp. 19-22).[23] Below OPG discusses each of these proposals and shows that they are contrary to the evidence, inconsistent with the OEB's long-standing regulatory practice and contrary to the best interests of consumers. For these reasons, each of the proposals should be rejected.

With respect to Issue 4.7, no party made submission on the treatment for the costs of the Pickering Units 2 and 3 isolation project and as such, OPG's proposed treatment should be accepted by the OEB as filed.

4.6.1 Board staff's Recommendation to Reduce Future Rate Base Should be Rejected

Board staff argues that because the actual nuclear rate base was less than was forecast in the last proceeding, OPG "over-recovered" (Board staff argument, p. 20). Based on this, staff argues that the OEB should reduce the forecast rate base in this proceeding by some $100M per year in the test period. As will be demonstrated below, staff relies on a selective and inaccurate review of the evidence as the basis for this conclusion. In addition, staff's recommendation is inconsistent with well established regulatory policy and OEB precedent.

[23] To the extent that other parties simply adopt Board Staff positions (e.g. SEC Argument, page 12), they are not separately noted. To the extent that they raise unique issues (e.g. AMPCO Argument, pp. 30-32), however, OPG responds below.

Board staff's argument here tells only part of the story. The source information on actual versus forecast nuclear rate base on which staff rely is found in the response to Board staff interrogatory 2 (L-01-002). This response is never cited in Board staff's argument. A review of this response reveals that staff does not analyze nuclear rate base as it claims. Rather, it reviews a portion of that rate base and ignores the more than one third of nuclear rate base comprised of un-amortized ARC. When the entire nuclear rate base is considered, staff's alleged 4.3 per cent and 4.5 per cent over-forecast figures for 2008 and 2009 fall to 1.3 per cent and 1.8 per cent, respectively. The revenue requirement impacts of the actual variance are $5M and $3M in 2008 and 2009 respectively.

Board staff also sought to show that OPG over-recovered depreciation expense because actual nuclear rate base was less than forecast (Tr. Vol. 10, pp. 163-164). Staff counsel tried repeatedly through cross examination to establish a figure for this alleged over-recovery, and when informed that the calculation was more complicated than his questions suggested, he asked OPG for an undertaking to perform the calculation (J10.13).

When OPG produced the requested information, rather than the over-recovery assumed by Board staff, however, it showed an under-recovery of depreciation expense, as follows:

> Therefore, the actual nuclear depreciation amounts for 2008 and 2009 are <u>higher</u> by $4.3M and $3.4M, respectively, than those underpinning the OEB-approved nuclear payment amounts and OPG under-recovered nuclear depreciation expense in 2008 and 2009. (J10.13).[24]

What OPG finds remarkable about this undertaking is not the fact that it under-recovered depreciation expense in the prior test-period. Any comparison between actual and forecast results will show numerous examples of where expenses differed from forecast – some higher and lower. Rather it is that Board staff, in purporting to show the over-recovery associated with forecast nuclear rate-base, would completely ignore the

[24] Board Staff, citing Ex. KT1.6, claim that document shows rate base related overearnings of $5.4M in 2008 and $7.3M in 2009. Again, these figures do not reflect the entire nuclear rate base because they simply ignore the portion of nuclear rate base made up of un-amortized ARC. For the entire nuclear rate base, the figures in Ex. KT1.6 are $2.4M in 2008 and $4.5M in 2009. The total of this alleged over-collection ($6.9M) is less than the under-collection of depreciation expense ($7.7M) in the prior test period (J10.3).

offsetting impact of the associated under-recovery of depreciation. This willingness to present half the picture and ignore evidence unfavourable to their argument demonstrates an element of “cherry picking.”

Board staff also recommends a reduction in test period rate base because projections at the time of the hearing indicated that 2010 capital expenditures would be $160M rather than the $172 previously forecast (Tr. Vol. 5, p. 124). Based on this projection staff recommends reductions in nuclear rate base of $6M in 2011 and $12M in 2012. Board staff’s position here should be rejected for the same reasons it was rejected in EB-2008-0272. There the panel held:

> The Board agrees that if capital expenditures are less than budget, there will be no revenue over-collection if the shortfall pertains only to projects with in-service dates beyond the test period. On the other hand, there will be some level of revenue over-collection if the shortfall pertains to projects with in-service dates in the test period. However, the Board accepts that any potential over-collection is short-term in nature because rate base will be corrected in Hydro One’s next application. (EB-2008-0272, pp. 36-37).

As can be seen from Tables 1a and 2 in Ex. D2-T1-S2, many of OPG’s projects extend over multiple years from inception to completion, so the impact of capital expenditures with in-service dates beyond the test period noted in the quote above is also applicable to some OPG projects. The largely self-correcting nature of rate base is shown in OPG’s evidence. While nuclear in-service additions were significantly below forecast in 2008, additions in 2009 were above forecast (Ex. D2-T1-S2, Table 4c). This is because while some projects may take longer than planned, they eventually do come into service. The reasonableness of OPG’s planned test period capital expenditures is addressed in the next section.

4.6.2 OPG’s Budgeting Process Yields a Reasonable Level of Capital Expenditures

Board staff questions the level of proposed nuclear capital spending in the test period based on a distorted view of both OPG’s process for developing its capital budgets and the OEB approval of capital spending (Board staff argument, pp. 20-21). As shown below, no adjustment in the test-period nuclear rate base is warranted because OPG has a robust process for evaluating proposed capital spending that is based on the level of investment necessary to sustain the nuclear units and the company's ability to execute projects (Ex. D2-T1-S1, p. 3). OPG's level of project spending has been benchmarked against and found to be consistent with that of other nuclear operators (Tr. Vol. 5, p. 199). Furthermore, OPG's view that a review of the nuclear capital budget is a review of an overall level of spending rather than any particular set of capital projects is consistent with the approach taken by virtually every regulated utility and the approach that the OEB has specifically endorsed in the past.

Board staff claims that OPG's proposed capital spending has not been reduced to recognize ratepayer impacts or "re-prioritized" (Board staff argument, page 20). Again, this claim is not accurate. Staff focuses exclusively on what happens at the Corporate level and ignores what happens in the Nuclear business unit where the capital budgeting actually takes place. As Chart 1 in Ex. D2-T1-S1 (page 4) and the explanation that follows clearly show, OPG's project spending is essentially constant from 2007 to 2012 in the face of rising labour and material costs and despite the fact that certain employee costs for sickness and vacation that had previously been part of Base OM&A are now included as project costs (Ex. D2-T1-S1, pp. 3-4).

OPG's approach to nuclear capital budgeting is discussed fully in its AIC (pages 33-36). That discussion will not be repeated here. In terms of reprioritization, OPG has explained that the priority of its nuclear projects is set by the nuclear Asset Investment Screening Committee as detailed in Ex. D2-T1-S1, pages 2-4 and summarized by this response:

> MR. WARREN: And if the actuals for 2010 come in at 160 million, would you be prepared to reduce -- is it reasonable to expect you would reduce 2011/2012 to 160?
>
> MR. LAWRIE: No. We believe that 172 is the preferred budget for and maintaining capital investments in our nuclear assets, based on benchmarking, and based on our ability to execute the capital works. And we would use our asset investment screening process, our project portfolio management process, to bring priority projects forward and have them executed (Tr. Vol. 5, p. 124).

Thus, there is no need to for corporate reprioritization of projects because the reprioritization takes place within the Nuclear business and respects the established envelope for capital spending that are consistent with, but somewhat below, historical norms.

Board staff recommends a specific reduction in nuclear rate base because OPG has chosen to defer the Darlington Weld Overlay and partially defer the Maintenance Facility Projects beyond the test period (Board staff argument, pp. 21-22). Board staff assumes, incorrectly, that because this particular project is being deferred, the necessary level of nuclear capital spending has somehow been reduced. Staff position is inconsistent with OPG's clear evidence on the project prioritization process and with the OEB's longstanding approach to reviewing levels of capital spending rather than specific projects.

As the OEB found in EB-2005-0001, EB-2005-0437 (February 9, 2006):

> 2.2.1 It is not the Board's role in a rates case to micro-manage Enbridge's capital spending plans for any given year. Generally, Enbridge must determine for itself what level of spending is appropriate for a relevant period. This process within the Company must involve a thoughtful and programmatic assessment and prioritization of projects that have ripened to the extent that there is confidence that they can and should be accomplished within the period. This is particularly so in an environment that has seen significant increases in energy prices and where the Company is seeking a very substantial increase in overall capital spending. It may be that the Company will have to make choices about which projects are most critical, and which may have to await completion until future periods.
>
> 2.2.2 The Board's role is to ensure that the Enbridge's total spending program is balanced in that it is not so low as to threaten the orderly maintenance and development of the system, nor so high as to place undue upward pressure on rates, either in the test year or some future period. In fulfilling this role the Board attempts to place the capital spending plans within historical norms, which can be presumed to have found that appropriate balance. If spending well in excess of historic norms is proposed, the Board must assess whether the increase is justified through the presentation of evidence regarding the Company's analysis, prioritization, and judgement respecting budget components. (EB-2005-0001, EB-2005-0437, page 9)

OPG's capital spending proposal is consistent with the Board's finding quoted above. It has a robust project assessment and prioritization process that is fully described in its evidence and was explained by the witnesses on the Nuclear Projects Panel (Tr. Vol. 5, pp. 114-210). Board staff's suggestion that this process has not been improved between this Application and the last is wrong; the improvements are fully described in evidence (Ex. D2-T1-S1, pp. 11-13).

The projects that OPG intends to undertake in the test period, whether released or to be released, are necessary either to meet regulatory requirements or to sustain the ability of the nuclear units to continue producing electricity safely and reliably (Ex. D2-T1-S1, pp. 15-16 and Table 3).[25] OPG is not proposing an expansion of its capital spending. To the contrary, the proposed capital budgets are below historical spending because they now include costs that were previously in Base OM&A (Ex. D2-T1-S1, pp. 4-5).

OPG submits, that it, <u>like every utility appearing before the OEB</u>, provides its best estimate of the specific capital projects that will make up its proposed capital spending in the test period at the time its evidence is filed. And, <u>like every utility appearing before the OEB</u>, as external factors impact on its ability to undertake specific project, as priorities change and as new opportunities emerge, it revises the specific list of projects to be accomplished in the test period to reflect these external factors and new opportunities by deferring some planned work and advancing other projects.

The OEB is well familiar with this in this process in the distributor context. A particular electricity distributor will plan to replace the poles on a specific street or a given gas distributor will plan to replace a specific section of pipe. Due to municipal restrictions that limit the ability to undertake work in an area or the emergence of other higher priority needs, some planned projects will not be undertaken. Instead, the utility will advance work from a future year and actually undertake some projects that were not included in its application. There is no difference between this and OPG's proposal to defer the Darlington Weld Overlay Project. The fact that OPG's capital budget contains a series of relatively large projects, rather than the smaller projects distinguished by location that typically comprise a distributor's portfolio, does nothing to change the principal involved -

[25] Board's staff's characterization of "Listed Work to Be Released" as not being part of OPG's Application is incorrect

except that because of their size, OPG's projects are subject to much greater scrutiny than that typically given to distribution projects.

The evidence in this proceeding confirms this process. In Ex. D2-T1-S2, OPG lists the projects that have emerged since the last application (Ex. D2-T1-S2, Table 1a). As OPG explains, while most of these projects were on the shown as "Listed Work to be Released" in the last application, one of the projects (#34012 – Vacuum Building Recurring Alternations) represents a new opportunity that emerged subsequent to the last proceeding (Ex. D2-T1-S2, pp. 2-3; Attachment 1, Tab 29). All of these projects, whether included in Listed Work to be Released or not, are supported by business cases and have been subject to a full review before entering rate base. In this way, OPG's large projects, are distinguishable from the smaller, more fungible projects undertaken by distributors because those projects rarely are supported by business cases that are subject to review in a subsequent proceeding prior to the project entering rates.

The OEB should decline the invitation from Board staff and others to begin micro-managing individual projects and abandon its long-standing approach of reviewing the reasonableness of the proposed capital budget. OPG's proposed level of capital spending is reasonable and should be approved.

4.6.3 AMPCO's Proposed Disallowances Should Be Rejected

AMPCO proposes that any amounts above the original project estimates for the Pickering Cafeteria and the Darlington Change Room projects, a total of $11.2M, should be disallowed (AMPCO argument, p. 30). While OPG has acknowledged that both these projects faced substantial challenges, the standard for approving capital investments is not perfection. AMPCO proposes that any deviation from the original project budgets should be viewed as excessive and disallowed. This view should be rejected. AMPCO has failed to establish that OPG acted imprudently with respect to the execution of either project. In addition, it has supplied no basis for disallowing all spending above the original project budget. As a result, no disallowance is warranted.

No party questions the need for the Pickering Cafeteria project. Pickering has some 3,500 employees who work at the plant on shifts (Tr. Vol. 5, p. 185). They are subject to a thorough security screening every time they enter the plant (Tr. Vol. 5, p. 186). It is not practical to require that employees take their meals off-site. The cost in terms of lost productivity would be enormous.

OPG candidly acknowledged that mistakes were made in the 2005 to 2007 period when this project was designed, contracted out and then executed. AMPCO attempts to extend this argument further and suggest that this project reveals some current inability to manage projects (AMPCO argument, para. 134). This claim is baseless. If there is one thing that OPG did do perfectly with regard to this project it was to conduct a critical review in order to learn from the problems it had encountered.

OPG filed an 87-page Post Implementation Review (PIR) of this project. This document reviews every aspect of the project's execution in detail (JT1.7, Part 1, Attachment 4). While this review found that the project has delivered its intended benefits and met the needs for which it was undertaken, it is blunt in its assessment of OPG's performance. AMPCO did not "uncover" the problems with this project, OPG did. It described them in detail, and presented four pages of recommendations intended to avoid them in the future (JT1.7, Part 1, Attachment 4, pp. 8-11). As OPG testified, the purpose of undertaking the PIR was to document the lessons learned and that purpose was fully realized in terms of cost saving on subsequent projects (Tr. Vol. 5, p. 184).

AMPCO's requested disallowance is based on the finding of the PIR. AMPCO's cross examination added nothing to what is already clearly stated in the document. Both law and policy suggest that the PIR should not be used as the basis for a finding of imprudence. The PIR is by its very nature a retrospective review conducted with the benefit of hindsight. It does not seek to assess how the project should have been conducted based on information that was or could have been known at the time the project was undertaken, which is an essential component of a proper prudence review. Rather, a PIR does exactly what a prudence review must not do - it uses hindsight and subsequently developed facts to analyze project outcomes.[26] From a policy perspective, basing a disallowance on the PIR can only work to discourage the candid review and

[26] *Enbridge Gas Distribution Inc. v. Ontario (Energy Board)*, [2006] O.J. No. 1355 (C.A.), pp. 3-4.

assessment of future projects. A result that is detrimental to the long-term interests of ratepayers.

With respect to the Darlington Change Facility, AMPCO makes two arguments. First, AMPCO questions OPG's decision to proceed with the project on a "fast track" arguing that OPG was aware of the vacuum building outage ("VBO") and had adequate time to prepare for it. Mr. Arnone explained that OPG based its preparation for the VBO on the assumption that it could continue to repair the existing change room because that approach would have been less expensive. At a certain point, however, it became clear that such repairs were no longer feasible. As a result, the facility had to be replaced and in so doing, OPG had to meet all health and safety codes applicable to new construction while continuing to ensure that the project was ready on time to house the additional employees necessary to complete the VBO. As Mr. Arnone explained:

> MR. CROCKER: Right. And you knew that you wanted to have that change room in place in time for that?
>
> MR. ARNONE: No. What happened is the change room that was there was found to be uninhabitable, and within the timing of the initiation of the project, we found that the building had to be removed from service because of mould and other issues, and at that point, had to initiate a project for its replacement.
>
> As you can appreciate, the Codes had changed from the time that the original change room had been built, because it was actually there from the beginning of station. So now we had to follow today's Code, today's, both fire code, building codes, and all of the requirements both from a security standpoint and other for working inside a nuclear facility.

AMPCO's second argument is that the costs of the project are excessive. There is no basis for adopting AMPCO's proposal to limit project expenditures to the initial partial release amounts (AMPCO argument, pp. 30, 32). As OPG's witness explained, the partial release BCS was undertaken when the project was in its initiation phase where only 40 per cent of the project's engineering has been completed and for which the Project Management Institute establishes a range +60 per cent to -40 per cent around the project's estimated cost (Tr. Vol. 5, pp. 201-203). The projects ultimate cost, based on the full release BCS, came in within the established range. Further, as Mr. Arnone's testimony quoted above demonstrates, the costs of this project are directly related to having to undertake it inside of the plant's protected area and having to meet the stringent standards associated with construction of a facility that shares common systems with a nuclear plant. In particular, the fire protection system for this project required CNSC approval (Ex. D2-T1-S2 Attachment 1, Vol. 4, Tab 4, pp. 1 and 4).

For all of these reasons, AMPCO's proposed disallowance related to these two projects should be rejected.

4.7 PRODUCTION FORECAST

Issue 5.2: Is the proposed nuclear production forecast appropriate?

This section addresses the arguments of Board staff, AMPCO, CCC, CME, SEC and VECC with respect to the adjustment for major unforeseen events (MUEs) that forms part of OPG's production forecast (Board staff argument pp. 85-87; AMPCO Argument paras. 146-152; CCC Argument paras. 118-120; CME Argument paras. 177-196; SEC Argument paras. 5.2.1-5.2.14; VECC Argument para. 31). It also addresses the arguments of Board staff and SEC regarding the Darlington Forced Loss Rate ("FLR") (Board staff argument p. 44; SEC argument para. 5.2.15). To the extent that matters raised in parties' arguments have already been addressed in OPG's AIC (pages 38-39), they will not be repeated here. Instead OPG will focus on correcting some obvious misstatements of the evidence and demonstrating that the OEB should adopt OPG's production forecast because it represents the most accurate forecast of test period nuclear production.

Major Unforeseen Events

Major Unforeseen Events Should be Included in the Determination of OPG's Nuclear Production Forecast

The parties above argue that the OEB should ignore the nuclear production forecast that underpins OPG's Business Plan and this Application. For various reasons – none of them good, they have collectively determined that the adjustment for MUEs approved by OPG's Board of Directors is inappropriate and should be ignored by the OEB. OPG wishes to emphasize that not one of these parties has introduced evidence that contradicts or even questions OPG's showing that MUEs have occurred in past years, have significantly impacted nuclear production in those years and are likely to occur in the future. Nor has any party introduced evidence indicating that OPG has over-estimated the impact of MUEs on production. This is not surprising as OPG's forecasted annual MUE impact of 2 TWh for the test period is substantially lower than the annual historical variance between actual and forecast production (3.5 TWh) (Ex. E2-T1-S1, Attachment 4, p. 1). Below, OPG refutes every reason offered for ignoring MUEs and conclusively establishes that the nuclear production forecast underlying OPG's Business Plan and this Application should be adopted.

Board staff's opposition to including MUEs in the nuclear production forecast is particularly surprising given its argument on this issue in OPG's last payment amounts application (EB-2007-0905). There Board staff argued:

> OPG states that it has not changed the fleet level uncertainty adjustment even though actual lost production from unexpected events has exceeded the adjustment level over the past several years (E2/T1/S1/, page 12 of 28, lines 6-9). OPG cites expectations that the initiatives to improve outage performance will effectively address the factors that have compromised its forecast in the past (E2/T1/S1/, page 12 of 28, lines 10-12).
>
> Board staff note that OPG has continued to use an unchanging adjustment factor for outages. This factor does not appear to reflect the historic performance in evidence. This means the production forecast may be misstated.
>
> When making submissions on this issue, parties may wish to address the following:
>
> Considering the increasing inaccuracy in OPG's forecasting between 2005 and 2009 is the forecast presented a reasonable basis for setting the payments?
>
> If OPG's forecast should be adjusted what evidence should the Board rely upon to make the adjustment? (Board staff Argument in EB-2007-0905, page 34).

Given this position, OPG would have expected Board staff to fully explain why it is now asking the OEB to reject the very type of adjustment that it previously suggested the

OEB should consider. The change in staff's position is baffling given that OPG has supplied two additional years of data showing that these types of unexpected events continue to occur and significantly impact the production forecast. OPG has also provided a method of classifying these unexpected events and a specific calculation of their impact to address the second question Board staff posed in the passage quoted above.

4.7.1 OPG's Business Plan Includes the Adjustment for Major Unforeseen Events

Several parties claim, in various formulations, that OPG's business plan adopted by the Board of Directors does not include the impact of MUEs (Board staff argument, p. 85; AMPCO argument, para. 146; CCC argument, paras 118-119; CME argument, para. 185; SEC argument, para. 5.2.10). This claim is false. The Business Plan approved by OPG's Board of Directors, endorsed by OPG's shareholder and on which OPG's Application and all of its financial forecasts are based, shows nuclear production of 48.9 TWh and 50 TWh in 2011 and 2012 respectively (Ex.J10.1, Attachment 1, p. 5).

As fully explained in OPG's evidence, interrogatories and during cross examination, the nuclear business plan contains a stretch goal to go beyond OPG's Business Plan and achieve annual production levels that are 2TWh higher than plan (Ex. E2-T1-S1, p. 11; L-12-018; Tr. Vol. 6, pp. 81-83). As Ms. Carmichael clearly explained:

> MR. SHEPHERD: And the one that you told your board of directors to rely on is 50.9 and 52; right? That is what you told them you were going to produce; right?
>
> MS. CARMICHAEL: We said we were going to stretch ourselves to produce that target, but that the OPG target, the OPG business plan, should include 48.9 and 50. (Tr. Vol. 6, p. 83)

4.7.2 It is Entirely Appropriate for OPG to Challenge Its Nuclear Business Units to Exceed Forecasted Production

In a completely transparent fashion, OPG has presented both the forecast of nuclear production that forms the basis of its business plan and the stretch target that it uses to challenge the Nuclear organization to do better than plan. Here again, OPG is hard pressed to understand why parties believe that is inappropriate for the company to use its best estimate of what it expects to produce as the basis of its business plan and then create stretch goals for its operating staff to do better than plan.

Ms. Carmichael explained OPG's reasoning as follows:

> MR. SHEPHERD: If you expect to get it, then why are you telling this Board your budget is two terawatts less? I don't understand.
>
> MS. CARMICHAEL: We are trying to drive our stations towards higher performance in producing generation for the company, as well as for the Province of Ontario. But because we always have these big one-time events that seem to be occurring, it would be inappropriate and inaccurate to submit a forecast without something like this in it.
>
> So that is why we are trying to drive our nuclear organization to better performance, but at the same time want to create a realistic and reliable forecast that the rest of the company and the IESO and everyone can rely upon.

CCC suggests that there is something untoward about basing incentive compensation on the company's targets and including a stretch goal to encourage superior performance (CCC Argument, para. 120). CME and AMPCO make related arguments (CME Argument paras. 189-194; AMPCO Argument, para. 147). OPG submits that both targets and stretch goals are routine elements of incentive compensation. OPG's target for nuclear production in its incentive compensation program is the nuclear production forecast that underpins both the 2010 Business Plan and this Application (J9.5). The stretch goal is 2TWh higher per year.

CME claims that OPG's stretch goals are not really stretch goals at all and "only exist because of the 2.0 TWh gap created between the MUE adjusted production forecast and the non-MUE adjusted forecast." (CME Argument, para. 193). CME's argument is not sensible. Stretch targets, as their name implies, exist to provide incentives for employees to exceed targeted performance levels. If the stretch goal were not set higher than the production forecast, it would not be a stretch goal.

Similarly, CME attempts to argue that because OPG's Nuclear organization expects to achieve the stretch goals set for it, these cannot really be stretch goals (CME argument para.186). OPG disagrees. As Ms. Carmichael testified, it is in the interest of the people of Ontario that OPG provide incentives to its employees maximize production from the nuclear assets owned by the Province (Tr. Vol. 6, pp. 82-83). Unless these employees believe that the incentives are achievable, however, they are unlikely to strive to realize them. Put simply, people who don't expect excellence, rarely achieve it. This concept is well captured in the slogan "Believe it, Achieve it" adopted by OPG's Nuclear organization.

Perhaps more fundamental, however, is what these arguments reveal about intervenors' views on how the OEB should select a production forecast. The OEB itself expressed the view that OPG should produce as accurate a forecast as possible:

> The Board 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. (Decision with Reasons, EB-2007-0905, p. 174)

Apparently, these Parties believe that rather than adopting the best available estimate of future nuclear production, the OEB should adopt a forecast that is biased high so that it is a virtual certainty that actual production will always be below the production used to set rates.[27] OPG urges the OEB to resist this invitation to adopt an unsupported and unrealistically high forecast simply to lower the payment amounts.

4.7.3 OPG's Response to Various Other Intervenor Arguments on MUEs

Board staff claims that MUEs are not really exogenous (Board staff argument, p. 86). This issue was explored in some detail during cross examination, where OPG explained that the type of events that it had characterized as "unforeseen" were not even considered as plausible by outside experts (Tr. Vol. 6, pp. 108-110). Thus there is no basis for staff's claim.

Board staff also argues that applying MUEs at the corporate level distorts the economics of investment decisions for the Pickering units because these units are, based on history, most likely to experience MUEs (Board staff argument, p. 87). Again, because these events cannot be foreseen they can happen at any unit and thus it is appropriate

[27] Because OPG has proposed only to include a 2TWh adjustment for MUEs rather than the full 3.5 TWh average difference between forecast and actual production, it is arguable that the proposed forecast remains biased high. On this basis, OPG believes that the current forecast is fairly characterized as challenging, but realistic.

to make the adjustment at the corporate level (Tr. Vol. 6, pp. 78-79). Moreover, because capital investments at Pickering are sustaining or regulatory, not value enhancing, their economics are evaluated to select the least cost alternative, and not based on incremental revenue.

CME claims that OPG's witness testified "that they were not aware of any other utilities either in Ontario or any other jurisdiction who used the MUE adjustment in their production forecasts." (CME Argument, para. 183). CME has mischaracterized OPG's evidence. What Ms Carmichael actually stated was that OPG does not know whether or not other utilities use such an allowance because forecasting methodologies are proprietary (Tr. Vol. 6, p. 81).

CME claims that OPG will collect $200M in revenues twice if the OEB approves OPG's nuclear production forecast (CME Argument, para. 188). This argument, as stated by CME, is incorrect. If what CME means is that OPG will earn additional revenue if nuclear production is higher than the approved forecast, then this is true in exactly the same way that OPG will earn less revenue if nuclear production is lower than the approved forecast; a situation that history has shown is the more likely of the two outcomes.

SEC argues that the proposed MUE adjustment is just double counting of the Forced Loss Rate. SEC goes so far as to characterize OPG's adjustment as "phony." (SEC Argument, para. 5.2.9). SEC's argument does not distinguish between the Forced Loss Rate, which accounts for station-specific factors that are anticipated to reduce production, and MUEs, which account for significant and unforeseen events that can occur at any station.[28] This matter was clearly addressed in response to an SEC interrogatory that posed this very question (L-12-17(a)). Since the SEC interrogatory duplicated one previously asked by Board staff, SEC was referred to the following explanation:

> As described on page 1 in E2-T1-S1, Attachment 4, examples of major unforeseen events include losses due to feeder thinning, an inter-station transfer bus issue, a resin release issue and calandria tube deterioration. OPG believes it is appropriate to separately

[28] Similarly, the fleet level adjustment accounts for known factors that could extend the planned outages at any of OPG's units (i.e., these factors are not specific to individual stations or units) (Ex. E2-T1-S1, page 10).

> identify the component of the production forecast associated with these types of events and to hold it at the business unit level rather than include it in the station FLR targets. This approach drives the stations towards stronger FLR performance as they are measured against stretch targets that do not include an allowance for major unforeseen events. In addition, major unforeseen events may occur at any station so it is not appropriate to build this allowance into individual station FLRs. (L-1-40).

SEC also claims to have found an inconsistency because OPG does not include the cost of outages related to MUEs in its OM&A budget (SEC Argument, para. 5.2.12). No such inconsistency exists. As OPG's evidence makes clear, it does not budget for any forced outages, whatever their cause (Ex. F2-T2-S1 pp. 1-2). The cost of forced outages is covered from the base OM&A budget.

SEC also claims that including MUEs in the production forecast is arbitrary and inconsistent with OPG's claims to be improving nuclear performance (SEC Argument, para. 5.2.5). Once again, SEC misses the point. OPG is working to improve nuclear performance by addressing known factors that tend to impact performance such as corrective and elective maintenance backlogs (See Ex. F2-T1-S1, Attachment 1, p. 10). MUEs are for unforeseen events that by their very nature cannot be addressed through improved maintenance.

4.7.4 OPG'S Test Period Target for the Darlington Forced Loss Rate is Appropriate

Board staff and SEC argue that OPG's target for the Darlington Forces Loss Rate (FLR), 1.5 per cent, is unreasonably high and does not represent continuous improvement (Board staff argument, p. 44; SEC argument, para. 5.2.15). Staff offers an alternative Darlington FLR target of 1.1 per cent, which it calculated by removing the 2006 actual FLR of 3.2 per cent from the five-year historical average because it declared this particular FLR to be an "outlier." SEC makes virtually the same argument, but calls the 2006 figure anomalous.[29] Board staff recommends removing $14M from the revenue requirement even though OPG's response to J3.2 makes it clear that changing the FLR does not impact the revenue requirement impacts, but rather impacts revenues by

[29] SEC's Argument at para. 5.2.15 erroneously states that OPG's proposed Darlington FLR target is 1.6% when it is actually 1.5%. Similarly, it shows 1.0% as the recalculated Darlington FLR rather than the correct figure of 1.1%.

increasing forecasted production. As shown below, this argument is both factually inaccurate and illogical and should be rejected.

Contrary to the claims of Board staff and SEC, the Darlington FLR forecast was not based on a historical average. Five-years of historical data were provided in response to an SEC interrogatory for the purpose of explaining why the use of a single year of exceptional performance, 2008, would be inappropriate (L-12-30).

OPG's evidence explains how the FLR targets were developed as follows:

> In 2010, FLR targets were developed by station management with input from the Outage and Strategic Planning Departments, Engineering, and Nuclear Finance. FLR targets are based on the plants' recent performance, any known improvements or deterioration in plant material condition, past and future investment in reducing corrective and elective maintenance backlogs to improve reliability and other performance improvement initiatives, as well as known risks (Ex. E2-1-1, p. 9-10)

No party ever seriously challenged OPG's derivation of Darlington's FLR based on OPG's methodology. Neither Board staff, nor SEC offer any reason why the actual results for 2006 should be considered so unusual as to be ignored. It is true that the 2006 figure is higher than other recent years, in the same way that the 2008 figure was considerably lower, but isn't the purpose of using averaging to smooth the impacts of both the high and low years?[30] Moreover, both Board staff and SEC have chosen to ignore the information OPG provided in response to Undertaking J6.5, which shows that the most recent forecast of the 2010 Darlington FLR, based on eight months of actual data, is 3.5 per cent. In light of this result, 3.2 per cent can hardly be considered an outlier and a forecast FLR of 1.5 per cent for 2011 and 2012 certainty represents a substantial improvement.

4.8 DARLINGTON REFURBISHMENT

> **Issue 4.4** – Do the costs associated with the nuclear projects, that are subject to section 6(2)4 and 6(2)4.1 of O. Reg. 53/05 and proposed for recovery, meet the requirements of that section?

[30] The 2006 FLR was twice the 5-year average, but the 2008 FLR was at less than half the 5-year average, which proportionately is even further from the average (L-12-30).

Issue 4.5 – Are the capital budgets and/or financial commitments for 2011 and 2012 for the Nuclear business appropriate and supported by business cases?

4.8.1 OPG Seeks the Following Approvals With Respect to Darlington Refurbishment

Introduction

Before dealing with the specific submissions of parties, it is useful to recount the approvals that OPG is seeking in this application. As set out in its pre-filed evidence at Ex. D2-T2-S1, page 4, it is seeking the following approvals associated with the project:

- Approval of test period OM&A costs (which form part of the Nuclear revenue requirement) of $5.9M and $4.5M in 2011 and 2012, respectively, for definition phase work for the Darlington Refurbishment project as presented in Ex. F2-T7-S1, Table 1.
- Changes in rate base, return on rate base, depreciation expense, tax expense and Bruce lease net revenues that result from the impacts of the service life extension, for purposes of calculating depreciation, and the change in the nuclear liabilities associated with Darlington Refurbishment.
- An increase in rate base to reflect the inclusion of Construction Work In Progress ("CWIP") for the Darlington Refurbishment Project as presented in Ex. D2-T2-S2.
- The recovery of the difference between forecast 2010 non-capital costs associated with the Darlington Refurbishment project and the costs underlying the payment amounts established in EB-2007-0905, as explained in Ex. H1-T2-S1.

The net effect of these changes is a reduction in the test period revenue requirement of $197.1M as can be seen in Table 1 of Ex. D2-T2-S2.

There are a wide range of submissions from the parties with respect to the approvals that OPG is seeking for the Darlington Refurbishment project. These are summarized below. Most parties support acceptance of the approvals (in whole or in part), with significant caveats. GEC opposes the project and submits that the OEB should not grant any of the approvals sought, resulting in a reversal of the accounting changes proposed by OPG and an increase in the revenue requirement.

OPG submits that based on the evidence in this proceeding, the OEB should accept the revenue requirement changes proposed by OPG and acknowledge that by so doing it is making a finding that OPG's decision to proceed with the Darlington Refurbishment project by undertaking the proposed test period project activities is reasonable.

Board staff, AMPCO, CCC, CME, SEC, the PWU and the Society made submissions indicating degrees of support for the approvals that OPG is seeking. GEC recommends that the OEB reject the Darlington Refurbishment project. VECC is in a confusing middle ground, recommending rejection of the project but acceptance of the net credit, exclusive of CWIP, during the test period (VECC argument, p. 10).

The Society submits that OPG has satisfactorily demonstrated that the Darlington Refurbishment project is the most economic means for ensuring the required nuclear base load generation and as such the project's budget should be approved (Society argument, p. 3). Similarly, the PWU submits that the 2011 and 2012 Darlington Refurbishment CWIP capital and OM&A budgets that flow from the decision to proceed with the project are prudent and reasonable and that the OEB should approve the recovery of these budgets as proposed by OPG (PWU argument, p. 61).

The Nature of the OEB's Approval

Board staff expresses concern over how OPG might interpret an OEB decision that includes the recovery of Darlington Refurbishment Project costs, including CWIP, in 2011-2012 rates (Board staff argument, p. 38). They characterize OPG's position as saying that approval of CWIP would amount to an implicit finding of prudence for the project (Ibid., p. 39). Their characterization of OPG's position is not correct. OPG has been clear that it is not seeking approval for the project or a finding that all of the future expenditures related to the project are prudent (Tr. Vol. 13, pp. 86 - 87). Instead, OPG is asking the OEB to approve the items set out in Ex. D2-T2-S1, page 4 on the basis that it finds it just and reasonable for OPG to proceed with the Darlington Refurbishment project and that the project work that it has identified for 2011 and 2012 and the underpinning end-of-life dates and accounting adjustments are likewise just and reasonable based on the information known today.

Board staff acknowledges, as do others, that if the OEB was to disallow the Darlington Refurbishment Project costs and service life adjustments, then the test period revenue requirement reductions would have to be reversed resulting in an increase of $197.1M (Ibid., p. 39). Perhaps as a consequence, they submit that the current business case provides minimal, but sufficient justification, to accept the revenue requirement implications of the plan for the test period, other than CWIP, but that it is not sufficient for the OEB to approve the post-2012 cost implications of the project (Ibid., p. 39). CCC similarly recommends acceptance of the revenue requirement implications for the test period, other than CWIP (CCC argument, p. 22).

As indicated previously, OPG is not seeking approval of costs beyond the test period. Therefore, in OPG's submission, the OEB does not need to address the issue of the sufficiency of evidence for post-2012 costs.

Board staff, AMPCO, and CCC encourage the OEB to explicitly state that approval of the project's test period revenue requirement implications should in no way be interpreted by OPG as an approval of the overall project and that the OEB is reserving its right to conduct a prudence review of the project, the outcome of which could be a disallowance of incurred costs and/or an unwinding of the service life assumptions (Board staff argument, p. 39; AMPCO argument, para. 113-114; CCC argument, p. 22).

In response, OPG submits that the OEB should confirm that its approval of the test period revenue requirement impacts and accounting changes constitutes its agreement that OPG's proposed test period activities are reasonable based on the evidence submitted by OPG. And any subsequent review that is required will go only to the prudence of OPG's execution of test period activities and not to the prudence of having undertaken these activities.

The OEB Should Not Seek to Micromanage the Project

While supporting approval of the test period impacts, other than CWIP, SEC goes further. SEC recommends that the OEB should advise OPG to aggressively limit its ongoing financial commitments on the project as these may not be approved by the OEB if the project does not ultimately proceed (SEC argument, p. 27).

OPG submits that the OEB should reject requests to hamstring OPG's execution of the project by getting it to minimize expenditures on the project during the test period (SEC argument, p. 27). Accepting these kinds of submissions could put the project's schedule at risk, drive up the project's costs and potentially impact the future reliability of the Ontario electricity system. These kinds of submissions should be completely discounted by the OEB.

In addition, these submissions ignore OPG's evidence on its plans for managing the project. As noted in Ex. D2-T2-S1, the Darlington Refurbishment project is a major undertaking that will be managed in phases to mitigate risk. Each phase requires that certain milestones be achieved before the project can proceed to a subsequent phase and before OPG's Board authorizes the expenditure of funds for that phase. As noted at Ex. L-07-035, OPG anticipates entering into a limited number of contracts during the project definition phase, however, OPG will limit its exposure under any long term contracts through appropriate risk mitigation measures including the inclusion of "out" clauses in certain contracts in the unlikely event that the project is delayed or cancelled. The OEB should reject intervenor submissions that would have it micromanaging this project as this is not an appropriate role for the OEB.

AMPCO makes a number of submissions that would involve the OEB in micro-management of the Darlington Refurbishment project and betray its particular fascination with AECL (AMPCO argument, paras. 123, 127, 128). In OPG's submission, the OEB should neither take on the role of managing the details of the project as AMPCO suggests or be drawn into its fixation with AECL. Neither of these roles is appropriate for the OEB as it executes its responsibility to set just and reasonable payment amounts.

Any Future Prudence Review Must Not Use Hindsight

CME recommends that the OEB make it clear to OPG that a failure to objectively establish and confirm that the project continues to have positive economic feasibility could lead to a write down of Darlington assets in a subsequent proceeding (Ibid., para. 124).

The OEB should also reject CME's submission as it would turn the OEB's traditional approach to prudence reviews on its head and use hindsight to say the project should not have gone ahead and that some or all of the costs should therefore be disallowed. This submission from CME completely ignores the OEB's prior decision on prudence reviews as set out in RP-2001-0032.

There the OEB defined its prudence review standard at paragraph 3.12.2 in the following way:

- Decisions made by the utility's management should generally be presumed to be prudent unless challenged on reasonable grounds.
- To be prudent, a decision must have been reasonable under the circumstances that were known or ought to have been known to the utility at the time the decision was made.
- Hindsight should not be used in determining prudence, although consideration of the outcome of the decision may legitimately be used to overcome the presumption of prudence. (emphasis added)
- Prudence must be determined in a retrospective factual inquiry, in that the evidence must be concerned with the time the decision was made and must be based on facts about the elements that could or did enter into the decision at the time. (emphasis added)

This approach was affirmed by the Ontario Divisional Court and the Court of Appeal in *Enbridge Gas Distribution Inc. v. Ontario Energy Board*.[31]

Various Intervenor Arguments that are Without Merit

CME asserts that OPG plans to proceed with Darlington Refurbishment project with financing through a combination of funds recovered in regulated payment amounts and funds to be "recovered from a new funding mechanism determined by the province for new nuclear". CME's assertion is not correct. OPG notes that the reference provided by CME regarding a new funding mechanism (OPG's AIC, p. 40) relates to new nuclear.

[31] See footnote 3 *supra*.

Darlington is a prescribed asset and therefore any refurbishment costs would be subject to recovery through the regulated payment amounts.

SEC also submits that OPG should be required to file in its next application a package of information equivalent to that to filed in a leave to construct application (SEC argument, para. 4.5.29) If OPG is not prepared to file on that basis, then it should obtain a “binding legal approval for the project from another source’ (Ibid.) In OPG’s submission, the OEB should reject this proposal from SEC. They offer no analysis or detailed explanation of why all of the elements of a leave to construct would apply to OPG’s Darlington Refurbishment project. Nor do they explain what kind of approval the OEB would make with a proxy “leave to construct” filing from OPG given the existing regulatory framework governing OPG (Tr. Vol. 13, p. 80, lines 16-26). While OPG agreed that some of the considerations that apply to the Darlington Refurbishment project would be similar to those from a leave to construct application (Tr. Vol. 14, pp. 13-14), this agreement does not mean that they would be the same or require the same evidentiary support. For example, OPG does not agree that it is useful to file evidence on customer “need” for a project that the Province has endorsed and then later placed within its Long Term Energy Plan.

GEC argues that OPG has failed to provide evidence that the Darlington Refurbishment Project is in the public interest and that the publication of the Long Term Energy Plan does not change this conclusion (GEC argument, p. 5). Accordingly, GEC submits that the OEB should not approve the various accounting changes that flow from the project including the new end-of-life dates for Darlington, resulting in the increase in the revenue requirement noted by Board staff above (Ibid. p. 5).

GEC is correct on what should happen if, contrary to OPG’s evidence and submissions, the OEB does not believe that OPG has justified its proposed test period spending and the accounting adjustments that it has made. In that case, the OEB should order OPG to reverse them. As Mr. Barrett stated:

> Now, presumably, if the Board had a view that it was not reasonable to proceed with the project, then they would not approve the things that flow from that.

> So for example, if they thought that it wasn't reasonable to proceed with the project, that those things that are set out -- let me just find a reference -- the things that are set out in chart 1 -- sorry, in chart 1 on Exhibit D2, tab 2, schedule 1, the Board would not incorporate those adjustments into the revenue requirement. So they would essentially reverse those things if they took that view (Tr. Vol. 13, pp. 83-84).

A complete reversal of the accounting adjustments, including those related to the Bruce facilities would raise an issue of consistency with the OEB's decision in EB-2007-0905 because in that decision the OEB ordered that the revenue requirement impacts from the Bruce facilities be done in accordance with GAAP.

However, in OPG's submission there is no basis for ordering any reversal. On the contrary, as discussed below, OPG submits that the evidence on the record supports a finding that it is reasonable and prudent for OPG proceed with its test period plans, expenditures and the resulting accounting changes related to this project.

4.8.2 The Darlington Refurbishment Project has been Approved by OPG's Board of Directors

OPG's own review of the evidence in preparing its AIC indicated that in an effort to be precise about the details of its gated approval and funding release process, the company has been less clear than it could have been about the approval status for the Darlington Refurbishment project. In an effort to remedy this, OPG's AIC was unambiguous in stating that the OPG Board of Directors has approved proceeding with the project.

Despite that remedy, parties, depending on their disposition toward Darlington Refurbishment, have offered the OEB various characterization of the approval OPG's Board of Directors has given to the project. Those parties who are opposed to Darlington Refurbishment wish the OEB to believe that the only thing that has been approved is the spending on the first release in the Definition Phase of the project (PP argument, p. 3; GEC argument, p.13). GEC's argument is notable in this regard as if repeating that the OPG Board has not approved the project frequently will make it true (GEC argument, pp. 11, 12, 19 and 22). Others point to ambiguity in OPG's description of what has been approved (SEC argument, para. 4.5.16). Supporters of Darlington Refurbishment agree with OPG's conclusion that proceeding with the project has been approved (CME argument, p. 34).

OPG wishes to reiterate that the Darlington Refurbishment Project has been approved by its Board of Directors and the company is proceeding with the project. The Minister of Energy has stated that the government concurs with the OPG Board decision and has included Darlington Refurbishment in both the Long Term Energy Plan and the Draft Supply Mix Directive (Ex. K16.2, p. 23; Ex. K16.3, p. 4). The fact that the project contains defined phases and requires certain deliverables be produced and accepted before the project can move to the next phase should provide the OEB and parties with clear evidence of OPG's ongoing commitment to carefully manage this project (Ex. D2-T2-S1, p. 6). Management and the OPG Board of Directors would not have approved the expenditures for the project's Definition Phase unless they were satisfied that the work completed in the Initiation Phase, provided a sound basis for concluding that the project should be undertaken (Ex. D2-T2-S1, p. 11).

4.8.3 The OEB can Rely on the Province's Determination that Darlington Refurbishment is in the Public Interest

Several parties argue that the OEB must determine that the Darlington Refurbishment Project is in the public interest before it can approve any costs related to the project (GEC argument, p. 25; Pollution Probe, p. 3; etc). OPG submits that the Province has already determined that the project is in the public interest. Based on the Minister of Energy's letter endorsing the decision to proceed with the project, and its presence in the Long Term Energy Plan and the draft Supply Mix Directive, there is a reasonable basis to conclude that this project has been determined to be in the public interest. As Mr. Barrett stated:

> MR. BARRETT: The minister, speaking on behalf of the project, has endorsed our plans for proceeding with the refurbishment of the Darlington plant.
>
> We take that endorsement of our plans as an indication -- or a determination by the province that proceeding is in the public interest, because I think the logic is that the minister or the province would not be endorsing something they thought was contrary to the public interest.
>
> I think, to be fair, that we would not say that public interest determination by the province is binding on the Board, but we believe that the Board should give it significant weight in its own determination of what is in the public interest. (Tr. Vol. 13, p. 149)

4.8.4 The Evidence Supports OPG's Very High Confidence in Achieving a LUEC of Between 6 and 8 Cents

Based on their view of the history of nuclear power projects, certain intervenors (EP argument, paras. 19-24; GEC argument, pp. 9-10; and PP argument, pp. 4-7) submit that the OEB should disbelieve OPG's cost estimates and accept as evidence their un-tested assertions that the costs of Darlington Refurbishment will be much higher than OPG predicts. Board staff also expresses scepticism about OPG's cost projections (Board staff argument, pp. 27-28). OPG submits that it is an unnecessary distraction to engage in a debate about the history of nuclear power in Ontario. Instead, the focus should be on OPG's strong evidence that its LUEC range provides a sufficient basis for accepting that the Darlington Refurbishment Project will proceed and for adopting the resulting revenue requirement impacts.

Pollution Probe provided no evidence on the costs of the Darlington Refurbishment Project, but in its argument, urges the OEB to find that OPG's costs estimate is not credible (PP argument, p. 4). Pollution Probe's submission should be rejected out of hand because it is based solely on a document that the OEB has already held is not evidence.[32] For example, in support of its claim: "During the last 25 years, Ontario's fleet of nuclear reactors has *never* achieved an average annual capacity utilization rate of 82 per cent or better (PP argument, p. 4), Pollution Probe cites an exchange between Mr. Alexander and Mr. Reiner (Tr. Vol. 6, p. 167, line 23 to p. 168, line 10).

However, the most that can be said from this exchange, and from other exchanges related to this document, is that Mr. Reiner did not dispute that the numbers being put to him were the numbers in the document that he was being shown. However, he did not agree that these numbers were correct or the conclusions drawn in the document were relevant to the Darlington Refurbishment project (Tr. Vol. 8, p. 104). For Pollution Probe to cite this exchange as support for their conclusion that a refurbished Darlington station will not be able to achieve an average annual capacity factor of 82 per cent to 92 per

---

[32] Pollution Probe's Argument makes repeated reference to the "The Darlington Rebuild Consumer Protection Plan", which was filed by PP as part of its compendium (K6.3). As the OEB held:" … the report itself is untested, and, therefore, any opinions or recommendations in the report carry no weight by virtue of them being placed before the Board through this report. The Board will look to the tested evidence in this proceeding to determine the merit of any opinions or recommendations put forward in argument." (Tr. Vol. 6, page 155).
.

cent is no more than a back door attempt to evade the OEB's ruling on the admissibility of the Pollution Probe Report.[33]

In terms of Darlington's capability factor and the reasonableness of OPG's estimated range, the following is in evidence:

Table 6: Performance Assumptions Used in the Updated Economic Assessment

Performance Factor	2008-2012 BP Average	High Confidence	Medium Confidence	Low Confidence
Gross Capability Factor (%)	91%	82%	**87%**	92%

> The 87 per cent capability factor (medium confidence) is equivalent to Darlington's average performance for last 10 years. It is considered conservative given the station's performance of 89.6 per cent over the last 3 years and would put the station in the 4th quartile of INPO plants. The low end performance of 82 per cent reflects the station's since-in-service performance and could result, for example, from a failure to effectively implement the integrated Aging Management Program ("IAMP") and/or an inability to maintain a 3-year outage cycle. It would also allow 20-month outages at year 15 post-refurbishment, if necessary, to replace steam generators. The high end performance of 92 per cent could be achieved if Darlington were to achieve and sustain 1st or 2nd quartile INPO performance, funding levels are maintained, the IAMP is effectively implemented, and Human Performance is maintained (Ex. D2-T2-S1, Attachment 4, p. 32,).

Pollution Probe's other attacks on the assumptions that underpin OPG's economic analysis suffer from the same lack of evidentiary support and are also factually inaccurate (PP argument, pp. 4-5).[34] It is clear that Pollution Probe lacked sufficient confidence in its "analysis" to have it sponsored by a witness and be subject to cross examination. Given that the proponent of this information has so little confidence in it, the OEB should be extremely sceptical of claims that rely on this document for support.

---

[33] GEC similarly disregards the Panel's ruling on the admissibility of the Pollution Probe Report by inserting a chart from that report into its argument (without attribution) and citing the statement of an OPG witness that he did not dispute a figure from the Report as if he had confirmed the accuracy of that figure (See GEC argument, p. 14, and ft. nt. 16).

[34] As another example, Pollution Probe refers to the Pickering A return-to-service as a refurbishment. Mr. Pasquet explained the difference at the Technical Conference:

> As indicated in Exhibit D2, tab 2, schedule 1, section 2.3, the term "refurbishment" is typically characterized associated with projects that extend the production life of the nuclear unit, and that is typically done in the order of 25 to 30 years. And that is done by replacing life-limiting components, such as steam generators or fuel channels or feeders.
>
> The Pickering A return to service project, in fact, restored units which had been laid up to power operation, without replacing any of the life-limiting components, which is a characteristic of a refurb, as I just described. (Tr. Tech. Conf., page 47).

Pollution Probe's attack on OPG's assumptions about the cost of capital for the Darlington Refurbishment is equally unpersuasive (PP argument, p. 5). Pollution Probe claims that Darlington Refurbishment costs are not credible because Darlington's cost of capital is less than the CIBC World Banks projection for Bruce Power. Again, there is no evidentiary basis in the record as to what CIBC World Bank is projecting as Bruce Power's cost of capital as the citation for this proposition ultimately relies on Pollution Probe's own report, which is not evidence. Moreover, even if true, this difference could be explained by the fact that, as Ms. McShane testified, Darlington as a regulated entity is less risky than Bruce (Tr. Vol. 11, pp. 20-22).

Finally, Pollution Probe states its view that based on history it is a virtual certainty that the Darlington will be subject to cost overruns. Energy Probe argues a similar point, albeit with more colourful language (PP argument, p. 6; EP argument paras. 19-24). Board staff also questions the reliability of OPG's costs estimates (Board staff argument, pp. 27-28).

OPG believes that these parties have failed to appreciate the change that the company has made to its project estimating and, more importantly, to its project management. In terms of estimating project cost, in this Application, OPG has deliberately avoided presenting a point estimate of the cost of Darlington Refurbishment. It has done so to avoid providing a more precise estimate than the current state of project knowledge will permit (Tr. Vol. 8, pp. 67-68). Instead, it has presented a range that accommodates a wide variety of outcomes with respect to key project cost determinants. This approach alone distinguishes this project from the Pickering A Return to Service example used by both Pollution Probe and Board staff.

In terms of project management, OPG has not only identified industry best practices but has also rigorously applied them (Tr. Vol. 8, pp. 67-69). The company is allowing sufficient time to undertake the analyses necessary to understand fully what is required in terms of cost and schedule to complete the project (*Id.*; Tr. Vol. 7, p. 38). In addition, the company is learning from the experience of others (Tr. Vol. 6, pp. 170-171). In particular, it has decided not to sub-contract the overall management of the project. This will allow OPG to better control the overall project schedule and ensure that all efforts are directed toward a single integrated schedule.

OPG's recent success in delivering large projects on time and on budget is an indication that these approaches are working (J8.3).

Board staff also questions whether OPG's assessment of Darlington Refurbishment cost was comprehensive (Board staff argument, p. 29). Below OPG refutes each reason Board staff offers for questioning OPG's assessment:

- Allocated corporate costs – OPG's economic assessment is an incremental analysis. Currently the corporate costs allocated to Darlington are $145M (not the $250M figure cited by staff, which is the total cost allocated to all of Nuclear). In this context the allocation of an incremental $40 million in costs is reasonable (Tr. Vol. 8, p. 92).
- Use of informed estimates for the range of inputs included in the Monte Carlo analysis - OPG did do a probabilistic assessment of certain inputs where it had sufficient historical data (see example, Tr. Vol. 8, p. 46). There is no reason to conclude, however, that its informed judgment on the likely range for the major variables is less valid than the range generated by a probabilistic analysis.
- Replacement power if steam generator replacement is required – OPG has very high confidence it will not have to replace the Darlington steam generators during the extended life of Darlington (Tr. Vol. 7, p. 22). This view was based on internal expert reviews and confirmed by external experts (Ex. L-7-028). In addition, as OPG testified, even if the replacement of the steam generators were found to be required as part of the refurbishment project, OPG's LUEC range of 6 to 8 cents for Darlington is broad enough to encompass the cost of steam generator replacement (Tr. Vol. 7, pp. 26-27). Further, replacement power is not properly part of a LUEC calculation (Tr. Vol. 7, p. 43). Moreover, LUEC does not consider either societal costs (such as replacement power) or societal benefits (such as economic impacts from projects multiplier effect) (Tr. Vol. 7, pp. 27-28; Vol. 8, pp. 12-14).

- LUEC does not include sunk costs – As OPG explained in J8.2 "LUEC is an economic measure which considers actual cost outflows associated with an economic decision. Neither non-cash items nor sunk costs are factored into a LUEC calculation." In making economic decisions about future options, sunk costs are not relevant.

4.8.5 OPG's Consideration of Alternatives was Appropriate

GEC and PP criticize, and Board staff questions, OPG's assessment of the cost of Darlington relative to a combined cycle gas plant. These parties also claim that OPG was required to assess a broader range of generation options as well as conservation (GEC argument, pp. 10-12; PP argument, p. 7; Board staff argument, p. 29). OPG disagrees. OPG assessed Darlington refurbishment against the other realistic options for large scale baseload generation (Ex. D2-T2-S1, Attachment 4, pp. 34-35). As discussed below, the Darlington Refurbishment cost compares favourably to the cost of those other options.

Both OPG and the OPA assessed Darlington refurbishment against a combined cycle gas turbine ("CCGT") (Ex. D2-T2-S1, Attachment 4, pp. 34-35; Ex. F2-T2-S3, Attachment 2). This technology was chosen because it represents a viable option for large scale baseload generation. Both OPG and the OPA found the forecast costs of a CCGT to be significantly higher than those forecast for Darlington Refurbishment.[35] GEC's argument that the greater ability to dispatch a CCGT relative to nuclear power plant was not properly considered in this analysis misses the point (GEC argument, p. 9). The analysis compared baseload options. When evaluating the lowest cost option for meeting baseload power needs, dispatchability is properly excluded from the analysis.

The OPA, the entity responsible for system planning in Ontario, re-affirmed that the project continues to be consistent with its view of system needs and is of lower cost than other available options including renewable sources (Ex. F2-T2-S3, Attachment 2). GEC

[35] Board Staff questions the sufficiency of the OPA's analysis and the depth of the OPA's support for the project because it was based on OPG's assessment of Darlington Refurbishment economics (Staff Argument, page 29). CCC states that OPA support for the project is irrelevant (CCC argument, page 21). OPG submits that the OPA is well versed in analyzing the costs of different generation options and one would expect that if they had any significant issues with OPG's cost estimates, their letter would have said so. In any event, the OPA letter speaks for itself and clearly states: "The OPA therefore supports the refurbishment of Darlington NGS based on expected electricity costs in the range of 6 to 8 cents per kilowatt-hour." (Ex. F2-T2-S3, Attachment 2).

claims that its evidence that the previous IPSP would have been more economic without nuclear generation was unchallenged and thus should be accepted by the OEB as proof that the OPA's current analysis of refurbishment is flawed (Ex. M7, p. 16). Here again, GEC goes too far. It's true OPG did not challenge GEC's witness' statements about the conclusions in the previous IPSP, but that is only because these conclusions are not relevant to any issue in this proceeding. As the OEB knows well, the previous IPSP was withdrawn and the Province has begun the process of developing a new IPSP. None of OPG's analysis of the costs of refurbishment relies on the previously submitted IPSP. In these circumstances, GEC's views on the correctness of the previous IPSP simply do not matter.

4.8.6 Ratemaking Proposals Offered by Various Parties are Unnecessary and should be Rejected

Variance Account Proposals

SEC has recommended that the OEB not approve the accounting changes related to the Darlington Refurbishment project and, on its incorrect calculation, increase the test period revenue requirement by $195.3M. However, they also recommend that the OEB establish a Darlington Refurbishment Accounting Variance Account and credit it with the same amount, $195.3M (SEC argument, paras. 4.5.31 and 4.5.37).

Given their expressed doubts about the merits of the Darlington Refurbishment project, they don't want to incorporate the "savings" to the revenue requirement associated with the accounting changes related to the project. They say that it is better not to take the benefit of these accounting changes until the project is "actually proceeding" (Ibid. para. 4.5.35).

SEC then goes on to say that if the project goes ahead there is considerable value in recognizing the accounting changes for ratemaking purposes at the same time as they were recognized by OPG for accounting purposes. They say their proposed variance account would do this and keep both OPG and ratepayers whole in the future (SEC argument, para. 4.5.37).

Setting aside SEC's wrong-headed analysis of the merits and certainty of the Darlington Refurbishment project, this variance account proposal was never introduced during the hearing. It suffers from this fact. It was never put to OPG's finance or variance and deferral account witnesses. If it had been, they would have been able to explain that the analysis on which it is based is wrong on several counts.

First, SEC's proposals are certain to create differences between OPG's accounting for ratemaking and for financial reporting purposes. For example, depreciation expense will likely be lower for accounting than for ratemaking. Similarly, the ARO will be lower for ratemaking purposes than in OPG's actual financial statements. The proposed creation of a variance account does not resolve this. If recognized on OPG's financial statements, this variance account would be a regulatory asset (separate and distinct from the ARO) and may be recognized as a reduction to revenues rather than to individual expense items, such as depreciation, on the income statement. SEC's argument assumes that individual expense items would be reduced on the financial statements, an assumption that OPG cannot confirm and the OEB should not accept.

Second, the proposed variance account is quite unusual and a significant amount of analysis would need to be undertaken by OPG, in consultation with its auditors, to establish the appropriate GAAP accounting treatment. In fact, it is far from clear to OPG that that the proposed account could even be recognized for financial statement purposes because it would be a "contingent" asset that would only be realized if the Darlington Refurbishment project ultimately did not proceed. And such a view would be inconsistent with the high confidence view that underpins OPG's GAAP adjustments, including the extension of the station's assumed end-of-life to 2051. SEC erroneously presumes that financial statement recognition of the proposed account is a given.

Third, SEC's accounting analysis is in error regarding the premise in paragraph 4.5.37 that "If the project is terminated, the accounting changes the Applicant will be required to make will be offset by the cash in the account." If the project is terminated, the accounting changes in the ARO and ARC will be accounted for prospectively over time starting at the point in time when these changes are made in accordance with GAAP (as required by CICA Handbook, section 1506, para. 32 and 38).

The clearest example of this is depreciation. If the Darlington life extension is reversed on the day the project is terminated, the higher depreciation expense will be spread over the remaining life of the Darlington station. However, the variance account (if originally recognized at all) would likely be reversed from OPG's financial statements immediately, resulting in a one-time income statement impact. Hence, there will be a mismatch between the higher depreciation (and other expenses) over time, starting at the point the project is terminated, and the immediate income impact recognized by OPG.

In summary, a divergence between accounting for financial statement purposes and for ratemaking purposes is inevitable given SEC's proposals. OPG also notes that SEC's submission with respect to the importance of consistency between accounting and ratemaking amounts on this issue is at odds with the position it has taken on pension and OPEB costs (SEC argument, para. 10.6.4). There, they say that "it is not obvious" to SEC why costs for pension and OPEB should be the same for ratemaking and accounting. SEC argues that the amounts should be included on a cash basis in rates, which is clearly not how they are accounted for in OPG's financial statements.

As with many of SEC's submissions, these complicated accounting maneuvers appear to be manufactured to justify its position that the test period revenue requirement reductions can flow to ratepayers without the need to express any views on the appropriateness of the underlying proposals. For all of the reasons expressed here and elsewhere in this argument, the variance account proposal from SEC should be rejected by the OEB.

VECC argues for the establishment of a variance account to allow the OEB to track the Darlington Refurbishment OM&A expenses for a future prudence review (VECC argument, p. 10). VECC urges the OEB to establish this variance account so it can claw back of all expenditures if the OEB "ultimately disallows all the costs associated with the DRP" (VECC Argument, para 28). This proposal implies that the OEB would use hindsight to determine at some later date that it was imprudent for OPG to have even entered the Definition Phase and spent the proposed OM&A dollars for 2011 and 2012. The Board staff proposal referenced by VECC (Board staff argument, p. 39), contemplates a review of the prudence of OPG's test period spending but not the repudiation of the project and disallowance of all its costs based on hindsight, as contemplated by VECC.

This type of hindsight review is inconsistent with longstanding OEB precedent on prudence reviews (RP-2001-0032, Decisions with Reasons, pp. 62-63). OPG submits that the OEB should reject this kind of thinking from VECC as being both patently unfair to OPG and completely contrary to the OEB practice on conducting prudence reviews.

In any event, as all Darlington Refurbishment project capital and non-capital costs are already covered by the variance account established by O. Reg. 53/05 section 6(2)4, VECC's proposal for a new variance account is unnecessary.

Interim Rates Proposal

SEC suggests that the OEB could move quickly to declare OPG's current payment amounts interim as of December 30, 2010 (SEC argument, para. 4.5.42) for the sole purpose of achieving retroactive ratemaking indirectly rather than doing it directly.

SEC believes that ratepayers should be credited $64.2M from 2010 related to the decision to proceed with the Darlington Refurbishment project. Since there is no variance account that would permit this amount to be brought forward into the test period to be returned to ratepayers, SEC has come up with its interim rates proposal. SEC argues that since the absence of a variance account for 2010 is really only a "technicality" the OEB should be prepared to adopt a countervailing "technicality" to achieve their requested result (SEC argument, para. 4.5.44).

SEC advocates declaring rates interim effective December 30, 2010 because they believe that for accounting purposes the actual entries for depreciation and nuclear waste and decommissioning liabilities and expenses take place at the end of the year. And until that time they have not occurred for accounting purposes (SEC argument, para. 4.5.4).

OPG hardly knows how to respond to this proposal from SEC. It is wrong on many levels. First, in OPG's submission, any recommendation that the OEB indirectly engage in retroactive ratemaking should be dismissed out of hand. The prohibition against retroactive ratemaking is a cornerstone of effective regulation everywhere that it is practiced. And the OEB should not accept the view that the existence of a variance account or the lack of a variance account is just a “technicality” that can be set aside for convenience after the fact.

Secondly, like the rest of the accounting evidence that SEC has included in its argument, the underlying accounting “analysis” put forward here is simply wrong. As a factual matter, the accounting changes with respect to ARO, ARC and Darlington life extension took place on January 1, 2010. This determination has been audited by OPG’s external auditors even before the 2009 year-end financial statements were issued in Q1, 2010 and are reflected in Note #26 (Subsequent Event) to OPG’s 2009 consolidated financial statements (Ex. A2-T1-S1, Attachment 2) and Note #19 to OPG’s 2009 financial statements for the prescribed facilities (Ex. A2-T1-S1, Attachment 3).

Therefore, the impacts flowing from these changes were finalized during Q1 2010 and were effective January 1, 2010 in accordance with GAAP. Then, as the year progressed, OPG simply reflected the impacts of these changes in its accounting records and the quarterly financial statements filed with the Ontario Securities Commission pursuant to the *Securities Act*. It is absolutely not correct to say that, the entries for depreciation and changes to the ARO are only recognized at year-end. Such an approach would be contrary to GAAP. In fact, CICA Handbook section 1751 at paragraph 25 specifically states that “an entity that reports more frequently than annually measures income and expenses on a year-to-date basis for each interim period, using information available when each set of financial statements is being prepared”. As such, attributing no value to OPG’s quarterly financial statements issued during 2010, as SEC does in its argument, is inappropriate.

Finally, the fairness point made by SEC is also completely off-base. OPG deferred making an application for 2010 to avoid burdening customers with another application right after the decision in EB-2007-0905. As a consequence, OPG significantly under-earned its allowed ROE for 2010. There are numerous examples where OPG’s costs were higher in 2010 or its production less than that included in rates. Yet here is SEC focussing on a single element where 2010 costs went down in the interests of “fairness”.

Capitalization of the Darlington Refurbishment Project Costs

Board staff argues that OPG has not fully demonstrated that 2010 was the proper time to start capitalization of costs given the project's early stage and its associated uncertainties (Board staff argument, p. 35). They suggest that capitalization should be put off until the 2013-2014 timeframe (Board staff argument, p. 35).

These submissions lack any evidentiary basis and should be rejected. Board staff's attempt to introduce new evidence by way of its Argument should be rejected in no uncertain terms. Fundamental fairness requires nothing less.

Board staff improperly attempts to use its argument to lead evidence on the proper interpretation of the CICA Handbook and the proper exercise of professional accounting judgment with respect to capitalization. It is not enough to simply quote a few sections from the CICA Handbook in an argument, include a few untested, unattributed assertions, and then say that the OEB should rely on this "evidence" in making its decisions on this issue. If Board staff wanted to lead evidence on this issue then they should have put forward a witness to speak to it, either an independent accounting expert or a member of Board staff knowledgeable about accounting, and have their evidence tested through cross examination and interrogatories. However, they chose not to do this. Accordingly, the OEB should give these submissions no weight at all.

These submissions also ignore the evidence and sworn testimony on capitalization put forward by OPG. As Mr. Reeve, a Chartered Accountant, testified, the decision to capitalize the Darlington Refurbishment project costs is consistent with OPG's accounting policy, OPG's past practice with respect to other large projects, and the CICA Handbook (Tr. Vol. 6, pp. 86-87; Tr. Vol. 10, pp. 89-92; Tr. Vol. 16, pp. 40-41). The decision to capitalize these costs has been audited and found appropriate by OPG's external auditors, Ernst &Young, as part of the audit of the 2009 year-end financial statements for OPG (see Note #26 to OPG's consolidated financial statements [Ex. A2-T1-S1, Attachment 2]) and as part of the audit of the 2009 year-end financial statements for OPG's prescribed facilities (see Note #19 to OPG's prescribed financial statements [Ex. A2-T1-S1, Attachment 3]).

In any event, OPG does not agree with the conclusions Board staff reaches from the quoted sections of the CICA Handbook. The appropriate CICA Handbook section to be used in assessing the capitalization of Darlington Refurbishment costs is Section 3061, not Section 3064. Section 3064 is incorrect because it deals with intangible assets, whereas Section 3061 effectively deals with physical assets. In fact, Section 3064 in paragraph 04 specifically refers to Section 3061 for guidance with respect to physical assets when it states: "Standards for the recognition, measurement, presentation and disclosure of tangible capital assets are provided in PROPERTY, PLANT AND EQUIPMENT, Section 3061."

OPG also disagrees with the view that Section 3061 does not provide sufficient guidance for determining when capitalization should commence. Paragraph 5 of Section 3061 specifically refers to costs directly attributable to a <u>betterment</u> of an asset and paragraph 26 of Section 3061 defines betterment as "the cost incurred to enhance the service potential of an item of property, plant and equipment." The paragraph goes on to state: "Service potential may be enhanced when there is an increase in the previously assessed physical output or service capacity, associated operating costs are lowered, the life or useful life is extended, or the quality of output is improved." As OPG's evidence demonstrates, it achieved a high confidence, effective January 1, 2010, that Darlington will be refurbished and operate to 2051 resulting in an increase in generation output over time (F4-T1-S1, Attachment 1, p. 6). Hence, it is appropriate to treat directly attributable expenditures on the Darlington Refurbishment project as a betterment and capitalize them effective January 1, 2010 in accordance with Section 3061, as OPG has done.

Finally, these submissions are completely inconsistent with Board staff's final position on Darlington Refurbishment project costs (Board staff argument, p. 39). This final position is that the OEB should accept, other than CWIP, that the evidence supports the revenue requirement reductions made by OPG. However, the logical consequence of their argument on capitalization is that the test period Darlington Refurbishment expenditures in the amount of $361M (Ex. D2-T2-S1, Table 3) would be treated as OM&A costs for ratemaking purposes (Tr. Vol. 16, pp. 40-42; J10.11, p.3). This treatment would of course increase the revenue requirement significantly during the test period.

4.8.7 OPG Will Report on the Darlington Project

In its next rates case, OPG will bring forward an update on the Darlington Refurbishment project and specifics on its planned expenditures and work plans for the 2013-2014 test period. At that time it would be seeking OEB approval for its new test period OM&A expenditures and for the inclusion in rate base of its new test period capital expenditures as part of an approval of Darlington Refurbishment CWIP in rate base.

In this way, there can be a series of regulatory reviews and approvals of the project. This approach would be broadly consistent with the "milestones/approval gates" model that OPG is using for managing the project and also consistent with the form of regulatory reviews that happen for large nuclear projects in other jurisdictions (Ex. D4-T1-S1, pp. 4-7).

In addition, the existence of the Capacity Refurbishment Variance Account will mean that any prior test period variances between the planned and actual OM&A expenditures and, assuming OPG's CWIP proposal is accepted, planned and actual capital expenditures would be brought forward for review. In that way, the OEB would be able, if it thought necessary, to conduct a prudence review of the work done and the money spent during the test period on the project. The proper focus of such a prudence review would be on how OPG executed against its plans and budgets for the project. However, in OPG's submission it would not be appropriate for parties to make submissions at that time, or for the OEB to make a finding, that it was imprudent for OPG to have proceeded with Darlington Refurbishment project and that all of the costs should be disallowed <u>unless</u> they can point to a fact that was known or should have reasonably been known at the time OPG moved into the definition phase.

5.0 CORPORATE COSTS

> **Issue 6.8** - Are the 2011 and 2012 human resource related costs (wages, salaries, benefits, incentive payments, FTEs and pension costs) appropriate?

> **Issue 6.9** - Are the "Centralized Support and Administrative Costs" (which include Corporate Support and Administrative Service Groups, Centrally Held Costs and Hydroelectric Common Services) and the

allocation of the same to the regulated hydroelectric business and nuclear business appropriate?

Issue 6.10 - Is OPG responding appropriately to the findings in the Human Resources and Finance Benchmarking Reports?

5.1 INTRODUCTION

In this area, parties have raised issues with respect to OPG's forecast compensation costs, reporting of employment and compensation levels, regulatory affairs costs and variances between forecast and actual corporate support costs. This section addresses those issues and shows that OPG's proposed spending is reasonable and should be approved. This section also addresses the relationship between FTEs and headcount and offers a proposal for future applications. As no other costs in this area were challenged, OPG's reply is limited to these matters. Given that there were no submissions on the other costs in this area, for all the reasons set out in its evidence and AIC, OPG submits that these other costs should also be accepted by the Board.

5.2 COMPENSATION

Parties generally challenged the wages that OPG pays to the unionized employees that represent approximately 90 per cent of its workforce. Parties also challenged OPG's forecast test period wage increases for employees represented by the Society of Energy Professionals whose contract expires at the end of 2010. Finally, parties requested that OPG be directed to use FTEs for both historical and future reporting of labour numbers.

5.2.1 OPG's Compensation for Unionized Employees Is Reasonable and Should be Approved

Board staff recommends that $37.7M be removed from OPG's annual revenue requirement based on the estimated cost of moving the 28 per cent of the unionized positions in OPG regulated operations identified in the Towers Perrin Study to the 50th percentile (Board staff argument, p. 66). SEC recommends a reduction of $101M split between OM&A and capital in the same proportion as used to allocate the compensation of unionized employees in the application (SEC argument, para. 6.8.11). CME, with the support of CCC, argues that the revenue requirement reduction could be almost four times greater than Board staff's proposal, $134.48M, by extrapolating Board staff's figure to OPG's entire represented workforce (CME argument, pp.163-165; CCC argument, p. 29).

None of these reductions should be adopted. OPG submits that, as fully explained below, the evidence in this proceeding supports the continued use of the 75th percentile within the Towers Perrin Power Industry survey as the appropriate benchmark for its unionized employees due to the nature and complexity of the work they perform. Moreover, even if the OEB determines that the 75th percentile is not the appropriate benchmark, there is no basis for selecting the 50th percentile as the appropriate standard. Ultimately, the OEB should recognize that OPG is bound by its collective agreements and cannot unilaterally impose changes in wages or conditions of employment on represented workers. Instead, it must negotiate these items with its unions. OPG submits that the evidence in this proceeding supports only one conclusion – OPG has aggressively negotiated wages and other employment terms and has achieved results that are fully consistent with the company's ongoing commitment to cost reduction.

OPG's evidence is that the 75th percentile of the Towers Perris Power Industry survey data is the appropriate comparator for its represented employees because of the breadth, and the complexity of the work they perform and the skills and training that they require (Tr. Vol. 9, pp. 43-44, 124-25). The skills and training required for OPG's employees are detailed in the AIC and will not be repeated here (see OPG AIC, pp. 46-47). Most of OPG's employees (95 per cent of the regulated workforce) work in or in support of its nuclear operations and are subject to the stringent safety requirements, exacting procedures and detailed training that characterize all aspects of nuclear generation. These factors impact the employees that support nuclear operations as well as those who work directly in the plants. For example, a "Junior Buyer," a PWU represented position, who supports nuclear must be familiar with the numerous requirements for nuclear qualified materials and the evolving standards for particular parts in specific nuclear applications (Tr. Vol. 9, p. 83). This is a fundamentally different level of knowledge than that required to buy stationery or even distribution cable at another utility.

Those employees working in or supporting Hydroelectric (5 per cent of the regulated workforce) also have substantial responsibility for the safe and efficient operation of OPG's hydroelectric assets, an important contributor to reliable electricity supply in this Province. Moreover, the collective agreements with the PWU and Society, do not distinguish jobs by generation technology. These agreements require that all employees be paid the compensation negotiated for their position and grade.

Board staff's suggestion that the impact of OPG's overwhelmingly nuclear workforce is already reflected in the Towers Perrin survey because the survey contains four other CNSC regulated employers is disingenuous (Board staff argument, p. 65). As Board staff could readily ascertain from the list of survey participants included in OPG's evidence, the great majority of these firms (22 out of 26) have no nuclear generation at all and of those that do, only Bruce Power and AECL have nuclear activities on a scale that is in any way comparable to OPG (Ex. F4-T3-S1, p. 37).

While it is true that many of the firms in the Towers Perrin survey are large, as Board staff suggests, only a handful of them are located in the Greater Toronto Area ("GTA"), like OPG. The OEB, as a GTA employer, is well aware that the cost of living, and hence compensation, is substantially higher in the GTA than in the other parts of Canada where most of the comparator firms are located.

Finally, the selection of the 50th percentile as the appropriate basis for comparison lacks any evidentiary support in the record. OPG provided evidence with its Application that the 75th percentile is the appropriate level of comparison (Ex. F4-T3-S1, p. 30). This evidence was sponsored by a witness with extensive experience in compensation (see Ex. A1-T9-S2, p. 11). No one filed any evidence that employees with OPG's skills and training, performing the functions that they undertake in an overwhelmingly nuclear environment should be benchmarked at the 50th percentile.

Instead, Board staff, SEC, CCC and CME have chosen to rely on nothing more than the bald assertions of their counsel as if it were self-evident that the 50th percentile is the appropriate benchmark. OPG submits that not only this assertion not self-evident, it is simply wrong. The OEB should not adopt it. If these parties believe that the work performed by OPG's unionized employees in an overwhelmingly nuclear environment should be compensated at no more that the median wages paid for similar, not identical, jobs in overwhelmingly non-nuclear workplaces across Canada, let them support this belief with evidence.

The fundamental question before the OEB is whether OPG's test year compensation expenses are reasonable. "Expenditures are deemed to be prudent, in the absence of some evidence suggesting the contrary." (*Enbridge Gas Distribution v. Ontario Energy Board* (2005) 75 O.R. (3d) 72 at para. 9 (Ontario Divisional Court.) Here, not only is there no evidence that the use of the 75th percentile as a comparator was imprudent, there is no evidence that there is any realistic alternative that would allow wages to be based on a different benchmark.

Exemplifying its all too frequent reliance on distortion and hyperbole, SEC's argument cites an exchange with OPG's compensation witness, Ms. Irvine, for the proposition that OPG doesn't "even want to know how their unionized workers compare to other companies. The information, they say, would be useless." (SEC argument, para. 6.8.5). That is not what Ms. Irvine said. What she said is that based on her experience, which spans almost 30 years and includes having led OPG's bargaining with the Society (Tr. Vol. 9, p. 22), external surveys are of limited utility in bargaining because the union bargaining teams are "more concerned about internal relativity than external." (Tr. Vol. 9, pp. 92-93).[36] This highlights the point that OPG made in its AIC (p. 47), that while the company attempts to control compensation costs, as it does with all costs, it can only do so within the context of its obligation to engage in collective bargaining.

It is easy to suggest as SEC and CCC do, that the OEB should reduce the revenue requirement by ignoring OPG's obligation to bargain in good faith and pretending that OPG can unilaterally set wages for its unionized staff. OPG submits that the OEB has a greater level of responsibility than these intervenors would ascribe to it. The OEB cannot ignore the undisputed evidence on the record that OPG must reach an agreement with its unions through negotiation or arbitration. These are the only avenues through which

[36] In a similar vein, SEC argues that OPG should attempt to increase its reliance on incentive compensation for its employees (SEC Argument, para. 6.8.15 -6.8.17) With respect to unionized employees, Ms. Irving testified that OPG's unions were not interested in trading lower fixed wages for an opportunity to earn increased incentive pay (Tr. Vol. 9, page 85-86). As an aside, SEC's statement that the Arnett Report recommended increasing incentive compensation for OPG management employees is in error. There is no such recommendation in the Report (K9.3, pp. 18-19).

OPG can establish compensation for its unionized employees and provide the context in which the prudence of the resulting compensation must be assessed.

In this context OPG fares quite well. The undisputed evidence is that for the 60 per cent of OPG employees represented by the PWU, the increases negotiated by OPG from 2001 through 2009 are less than those negotiated by any other successor company (Ex. F4-T3-S1, p. 9, Chart 5). For the Society, OPG wage increases over this period are among the lowest of the successor companies (Ex. F4-T3-S1, p. 9, Chart 6). Board staff's argument quotes "testimony" from staff counsel to the effect that such comparisons can be manipulated depending on the positions chosen (Board staff argument, p. 67). OPG wishes to emphasize, however, that the comparisons relied on do not depend on the comparability of individual positions. Instead, the data in Charts 5 and 6 cover the average annual increases (or the salary schedule adjustments) for all represented employees in the PWU and Society respectively.

The OPG's success in controlling wages is particularly well illustrated by comparing OPG's compensation rates for PWU represented employees to those for employees in the same job classifications at Bruce Power, the only other large nuclear operator in Canada. In its evidence, OPG presented a chart comparing its hourly pay rates for PWU positions with those at Bruce Power (Ex. F4-T3-S1, p. 32, Chart 12). This chart shows that of the 20 common classifications, Bruce Power pays higher wages in 18 and OPG's wages are higher in 2. On a weighted average basis, OPG's wages are 10 per cent lower than those of Bruce Power (Ex. F4-T3-S1, p. 32). Given that until May 2001, Bruce Power employees were employed by OPG and earned the same wages as all other OPG staff, this comparison again demonstrates OPG's success at limiting wage growth in its negotiations over the past decade compared to Bruce Power.

While OPG is limited in its ability to control wages by the fact that 90 per cent of its employees are unionized, OPG's evidence does conclusively demonstrate that the company has moved aggressively to lower labour costs where possible. OPG increased productivity by negotiating Skill Broadening with the PWU to increase productivity and end traditional job family silos (Tr. Vol. 9, pp. 80, 122-123).

With respect to management compensation, OPG reduced total senior executive compensation by 12.65 per cent between 2006 and 2009 (J9.7). To promote transparency, OPG's senior management compensation is available on its website. To implement the *Public Sector Compensation Restraint Act, 2010,* OPG also eliminated all of the non-unionized employee salary increase for the period covered by the legislation (i.e., through March 31, 2012).

The company has also been controlling labour costs by reducing headcount. For example, nuclear headcount which peaked in 2008 at 7,348 regular staff is expected to fall to 6,662 regular staff by 2012 (J4.4). As a result, of these actions, OPG's total employee cost is expected to decline from a high of $1,439M in 2009 to $1,402M in 2012, despite the projected increases in unionized wages.

5.2.2 Proposal for an External Study of Total Compensation

Board staff and SEC recommend that OPG be ordered to conduct an external study of unionized compensation and benefits (Board staff argument, p. 68; SEC argument, para. 6.8.14). OPG does not believe that external study of total compensation should be ordered for two reasons. First, developing such a study would cost a significant amount of money ($0.5M to $1M) because of the work entailed in determining comparable positions, given the limited number of nuclear operators in Canada, and comparing benefit costs (Tr. Vol. 8, pp. 193-194; Tr. Vol. 9, p. 92). Second, as previously noted, no matter what the outcome of such a study, compensation and benefits for unionized workers can only be set through collective bargaining. That said, if the OEB believes that such a study is necessary and provides the funding to undertake it, OPG will, of course, bring forward a responsive study in its next application.

5.2.3 Miscellaneous Proposed Adjustments That Should be Rejected

Board staff's proposed adjustment to reduce the test period Society salary increase to 2.5 per cent ignores the 1 per cent of OPG's proposed 4 per cent increase that is for progression within salary bands and promotions between salary bands. Board staff has provided no reason, let alone any evidence, as to why the costs of progression and promotions should be excluded from rates. Nor has staff explained or provided any evidence to support its apparent view that a base increase of 1.5 per cent (the proposed

2.5 per cent minus the 1 per cent required for progression and promotions) is the likely result of arbitration.[37] Given the fact that employees of the only other Ontario Hydro successor company to have undergone arbitration since the passage of the *Public Sector Compensation Restraint Act* received 3 per cent not including progression and promotion, OPG submits that no reduction is warranted in the test period. In any event, however, progression and promotions must be accounted for, which indicates that even if the Board staff view is adopted, the resulting reduction should be at most 0.5 per cent.

SEC proposes to eliminate the licence retention bonus and impose a revenue requirement reduction of $14 million in the test period (SEC argument, para. 6.8.19). The sole rationale offered for this reduction is that these bonuses do “not appear to have a comparable in any other regulated utility in Ontario.” This is not surprising as there is no other regulated utility in Ontario that asks its employees to devote significant amounts of their own time and effort to maintaining their qualification to operate a nuclear power plant. These bonuses are appropriate because, as Ms. Irvine explained “The maintenance of the authorization requires a great deal of personal time devoted into studying, writing exams, those kinds of things” (Tr. Vol. 8, pp. 176-177). Bruce Power, the only other entity that operates nuclear power plants in Ontario, also pays these bonuses (Tr. Vol. 8, p. 179). SEC proposed a similar reduction in the last proceeding, which was rejected (EB-2007-0905, p. 31). The OEB should do so again.

5.2.4 Impact of Compensation Adjustments

It is important to understand the relationship between reductions to compensation and other reductions. As SEC recognizes, to the extent that the OEB reduces OM&A, and, to a lesser extent, capital, in any other area, it is effectively reducing labour costs (SEC’s argument, para. 6.8.12). Labour makes up the great bulk of OPG’s OM&A expense and a smaller, but significant, portion of capital expenses. Failure to recognize this interrelationship could lead to double counting of reductions.

[37] Staff appears to assume, again without providing a reason let alone any evidence, that 3% is the maximum increase an arbitrator could grant. This is simply not the case. An arbitrator could approve an increase of more than 3% and OPG would be bound to pay it according to its collective agreement with the Society.

This type of doubling counting error can be most clearly seen in the staff's "OM&A Summary Table" (Board staff argument, pp. 78-79). For example, the $0.5M for Saunders Visitor Centre OM&A consists largely of the labour cost of the employees who operate and maintain the Centre. If this proposed cut were to be made, the salaries of those OPG employees would no longer be included in the payment amounts. To then apply a blanket reduction to compensation without first removing the compensation that was forecast to be paid to Visitor Centre employees would be a classic example of double counting a cut.

5.3 EMPLOYMENT LEVELS AND REPORTING

5.3.1 Employment Levels

Board staff, supported by VECC, recommends that the OEB should note the fact that in staff's view "OEB appears to have collected $106M on account of its last proceeding that it did not spend on employee compensation and Board staff submits this should be taken into account in determining the appropriate compensation amount to be included in OPG's revenue requirement" (Board staff argument, p. 70; VECC argument, para. 51). Below OPG explains why staff's analysis is factually incorrect, inconsistent with their argument on compensation and counter to well established regulatory precedent.

Board staff's analysis is factually wrong and illustrates the danger of relying on assertions made in argument that were never properly developed and tested during the evidentiary portion of the proceeding.[38] The table below demonstrates that when the actual and budgeted FTEs are viewed on a comparable basis, rather than the $106M over-collection described by staff, OPG actually under-collected its nuclear labour cost by $15M.

[38] Board staff had opportunities to verify their calculation during interrogatories and obtain further detail on it in the technical conference. They did neither. Instead they put their complex, incomplete and ultimately incorrect calculation to the wrong witness during cross examination and asked for confirmation (Tr. Vol. 8, pp. 211-213). Board staff counsel acknowledged that he was asking the wrong witness (i.e., questions about nuclear FTE information that appeared in the evidence sponsored by the Nuclear Base OM&A panel were asked of the corporate compensation witness) (Tr. Vol. 9, pp 5-6). If staff seriously wished to obtain a calculation from OPG, the evidence in this proceeding clearly demonstrates that they know the proper way to go about it. Instead they chose to rely on untested and inaccurate information to reach an incorrect conclusion and argue for a substantial disallowance based on their mistaken analysis.

Correction of Board Staff's Nuclear Labour Over-Recovery Calculation

Line No.	Resource Type	2008	2009	Total	Data Source
		(a)	***(b)***	***(b)***	***(d)***
	Regular Staff FTEs				
1	Planned FTEs - Gross	8,109	7,934	16,043	EB-2007-0905, F2-T1-S1 Table 1, Lines 14-15
2	Actual FTEs (EB-2010) - Net	7,302	7,297		Undertaking J4.4
3	Adjustments for changes between EB-2007-0905 and EB-2010-0008 tables	357	763		See: Note 1 below
4	Actual FTEs (EB-2010) - Gross	7,659	8,060	15,719	Undertaking J4.4 + Adjustments
5	Variance = Line 4 – Line 1	(450)	126	(324)	
6	Regular Staff Cost Variance @ $0.116M/FTE			($38M)	Ex. K8.3, Pg 67 (Board staff cost reference)
	Non-Regular Staff FTEs				
7	Planned FTEs	379	251	630	EB-2007-0905 F2-T1-S1, Table 1, Lines 14-15
8	Actual FTEs	720	732	1452	EB-2010-0008 F2-T2-S1, Table 13
9	Variance = Actual less Plan	341	481	822	
10	Non-regular Staff Cost Variance @ $0.064M/FTE			$53M	Ex. K8.3, Pg 67 (Board staff cost reference)
11	**Net "Cost Variance"**			**$15M**	

Note 1: Undertaking J4.4, removed certain employees in order to put the FTE numbers from the previous application on a comparable basis to those shown on EB-2010-0008, Ex. F2-T2-S1, Table 13, which is the table referenced in Board staff's request for undertaking 9.1. The employees removed are in Generation Development (refurbishment and new build) and Security. These employees had been included in Ex. F2-T1-S1, Table 1, Lines 14-15 in the prior application, but are excluded from the Ex. F2-T2-S1, Table 13 in this Application because that table only shows Nuclear Operations. Nuclear Generation Development and Nuclear Operations are presented in separate exhibits in the current filing to clearly show the costs of these two functions. In addition, while it was possible to mask Security staff numbers in the previous filing, it was necessary to remove them in this filing, as their impact on Nuclear Programs and Training staff level trends could potentially allow deduction of actual security staff numbers. This was explained in the notes to undertaking J4.4 (third bullet) as follows:

> 2007 Actual FTEs have been restated from EB-2007-0905 EX. F2-T2-S1 Table 1 *(sic- should be Ex. F2-T1-S1,Table 1)* to exclude refurbishment, new build and security staff. This is consistent with the basis for EB-2010-0905 (*sic – should be 2010-0008*), and all other data presented in the table above.

In order to make an "apples to apples" comparison between the Board approved FTEs in EB-2007-0905 and actual 2008 and 2009 FTEs, the excluded FTEs in Undertaking J4.4 need to be added back in. This is the adjustment made on Line 3 above for regular employees. No similar adjustment was required for Non-Regular staff because there were minimal non-regular staff involved in the Generation Development and Security functions in 2008/2009.

Board staff's position is also inconsistent with its overall position that OPG's labour costs are too high. As demonstrated above, in OPG's heavily unionized environment, where it is unrealistic to assume that OPG will be able to negotiate substantial reductions in wages, an important tool to control labour costs is limiting the number of employees. This involves the use of contractors, non-regular staff and overtime to the extent that business needs warrant and the collective agreements permit. Rather than criticizing OPG for limiting its labour expenditures over the past test period, staff should be applauding these efforts and encouraging OPG to go further.

Board staff's approach also runs counter to several well established regulatory principles. The first is that in forward test-year ratemaking, the regulator sets rates based on its view of the costs necessary to fund utility operations in the test period. It does not first establish reasonable test period costs and then adjust them based on the whether any particular item was under or over-recovered in a prior test period. If OPG had pointed to the actual $15M under-collection in 2008-2009 labour costs as a justification for increasing costs in the test period, staff and other parties would have responded in no uncertain terms that prior period under-recovery is irrelevant to the determination of reasonable costs in the test period. This principle applies with equal force to staff's approach.

Second, taken to its logical conclusion, Board staff's proposal is nothing short of retroactive ratemaking. In essence, Board staff would have the OEB reduce the reasonable level of forecast costs to recover a claimed, but actually non-existent, over-recovery of prior period labour costs.

5.3.2 Reporting

The OEB's *Filing Guidelines for Ontario Power Generation Inc.* (*Filing Guidelines*) specified the employment and compensation information that OPG was expected to file in this proceeding as follows:

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

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

Information will be presented in terms of FTEs. In some cases, OPG may choose to provide the information in terms of FTEs as well as head count.

The basis for each breakout of compensation data will be specified:
- Head count or FTE
- Yearly average, mid year or year end (*Filing Guidelines*, page 16)

OPG's Application is based on these *Filing Guidelines.*

OPG received relatively few interrogatories in this area and answered them fully (see examples, Ex. L-04-031; Ex. L-14-021). During the hearing, however, parties requested substantial additional information and different cuts of the existing information. OPG provided this too (see examples, J4.4; J9.1; J9.6; J9.7). In order to avoid having to scramble to produce information during future hearings, OPG is prepared to commit to filing the equivalent of Appendix 2K for Electricity Distributors, which is based on FTEs. In this document, OPG will clearly specify all assumptions used to make the data conform to the format of Appendix 2K and provide historical and forecast information on a comparable basis.

5.4 REGULATORY AFFAIRS COST

Board staff with the support of CCC, SEC and VECC proposes cutting the budget for OPG's Regulatory Affairs and Corporate Strategy department ("Regulatory Affairs") by between $4.2M and $5.7M over the test period (Board staff argument, pp. 70-73; CCC argument, p. 30; SEC argument para. 6.9.1; VECC argument, p. 16). As OPG demonstrates below, this recommendation is based on an incorrect and incomplete analysis of Regulatory Affairs' costs and is inconsistent with Board staff's own view, as expressed elsewhere in Board staff's argument, on the level of regulatory effort that will be required in the test period. The proposed cuts should be rejected and the budget for Regulatory Affairs should be adopted as proposed.

Board's staff argument proceeds from several faulty premises so it is not surprising that it reaches an erroneous conclusion. The first faulty premise is that the costs of developing and litigating a future payment amounts application are largely captured in the 2008 actual figures taken from the table in Board staff interrogatory 103. They suggest that the 2008 costs should be the "benchmark" for assessing future Regulatory Affairs costs. This premise is faulty for two reasons. First, the 2008 actual costs do not reflect all of the costs of the last payment amounts proceeding, which was filed on November 30, 2007. A substantial portion of the costs related to the last application occurred in 2007. For the two applications that OPG has filed to date, the process from developing the evidence through the end of the hearing took about 18 months. Thus while most of the actual hearing in the last application occurred in 2008, a significant portion of the cost and effort to develop the application occurred in 2007. As can be seen from the table cited by Board staff (Ex. L-01-103), there was another $538K of non-recurring regulatory costs in 2007 (Board staff argument, p. 71).

The second faulty premise is that the cost of OPG's first payment amounts proceeding is an accurate proxy for the cost of future payment amounts proceedings. As Mr. Staines explained, the company has modified its approach to preparing for rates proceedings before the OEB since 2008, with more of the burden being assigned to Regulatory Affairs and less on the business units (Tr. Vol. 8, p. 139). This has necessarily resulted in more resources and expenses being budgeted in this department. Given that 2008 was OPG's first payment amounts proceeding it is not surprising that OPG would make changes to improve the way it plans and budgets for future proceedings.

As well, the course of this hearing as shown conclusively that as the parties become more familiar with OPG, the depth of inquiry, and the number of areas that OPG must be prepared to explain and defend, has increased. Based on this experience, OPG will evaluate the lessons learned in this proceeding and, consistent with the company's desire for continuous improvement, determine how best to structure and develop the evidence needed for future cost-of-service applications. This will be a substantial effort involving internal staff, outside counsel and consultants. Thus, the extent of this proceeding itself supports the need for a substantial increase in the Regulatory Affairs' budget relative to 2008.

In addition, the next payment amounts proceeding will involve substantial issues that will require additional resources to develop and present. Those issues known today include the Niagara Tunnel, International Financial Reporting Standards ("IFRS"), Pickering B Continued Operations and Darlington Refurbishment. Other issues are sure to emerge.

Finally, OPG has committed to assessing incentive ratemaking in 2011 (See Section 14, Methodologies for Setting Payment Amounts). Board staff and others have offered a number of alternative proposals for how an Incentive Regulation Mechanism ("IRM") could be developed, all of which would require substantial effort by OPG Regulatory Affairs staff and external resources. Board staff also urges that OPG consult with stakeholders "early and extensively." Clearly, a disconnect exists between Board staff's proposal to reduce the Regulatory Affairs' budget and its suggestions with respect to IRM development.

The disconnect between staff's proposal and anticipated regulatory activity over the test period is not limited to IRM. Throughout their arguments, Board staff and intervenors urge the OEB to direct OPG to undertake numerous external studies and additional reporting. The table below lists the requests by issue. While OPG has opposed many of these studies as unwarranted and expects that the requests will be rejected, the fact that this additional information has been requested is in and of itself indicative of the level of future effort and cost that will be required of Regulatory Affairs.

Studies and Analyses Requested

Issue	Study or Analysis	Reference
Unionized Worker Compensation	External benchmarking study of compensation and benefits for OPG's unionized workers	Board staff argument, p. 68
Nuclear Fuel Procurement	External study of OPG's fuel procurement practices	VECC argument, para. 43
Niagara Tunnel	Annual Progress Report	SEC argument, para. 4.1.5
Employment and Compensation	Report in the form of Appendix 2K for electricity distributors	SEC argument, para. 6.8.3
Nuclear Benchmarking	Study of the major differences between CANDU and PWR/BWR	SEC argument, para. 6.4.6

Other Costs	Report on actual HST and ITC	Board staff argument, p. 78
Other costs	Analysis of taxes prior to April 1, 2005	SEC argument, para. 10.2.111
Other costs	External depreciation study	Board staff argument, p. 77
Reporting and Record Keeping	Various proposals	SEC argument, pp. 79-80 Board staff argument, pp. 102-103

The third faulty premise is that Board staff fails to understand the Regulatory Affairs budget covers OPG's costs related to other regulatory activities, including other OEB proceedings and interaction with other regulatory bodies, not just those related to OPG's payment amounts (Ex. F3-T1-S1, pp. 7-8). For example, OPG expects to be active in the proceeding related to the OPA's new Integrated Power System Plan in 2011-2012 and that participation will have to be funded out of the Regulatory Affairs budget. Regulatory Affairs is also responsible for certain activities related to the IESO market rules and development work, support for the company's strategic planning process and other strategic analyses, part of which is allocated to the prescribed assets under the OEB-approved cost allocation methodology.

Even the math that underpins the budget versus actual "analysis" that is provided on page 71 of the Board staff's argument is wrong. First, despite the clear statement provided on page 1 of Ex. L-01-103 and the evidence provided by Mr. Staines (Tr. Vol. 8, pp. 146-147) that legal costs are not part of the budget for Regulatory Affairs, Board staff has failed to back out the cost of legal services from the totals that they use in their calculations. Once this is done, the Regulatory Affairs budget assigned and allocated to the prescribed assets is $5.86M in 2011 and $8.1M in 2012 (Ibid.). Board staff's primary proposal for reductions would amount to about 40 per cent of this budget in 2011 and about 25 per cent in 2012. In addition, if Board staff wants to look at the change in the total budget for the Regulatory Affairs department they should look at Ex L-01-090 rather than Ex. L-01-103. That exhibit shows that the 2011 Regulatory Affairs budget is actually 8.4 per cent less than the 2010 budget (compare p.3 with p.4) and that the 2012 budget, which includes a major rates hearing, is only 9.9 per cent higher than 2010 (compare p.3 with p.5).

Board staff offers an alternative approach to justify cutting Regulatory Affairs costs, but it is equally flawed (Board staff argument, p. 73). Below OPG reproduces Board staff's table and refutes the conclusions reached with respect to each line.

Board Staff Table of Reductions (Board staff argument, p. 73)

Reductions in Millions	**2011**	**2012**
½ of the increase in recurring costs as compared to 2009 actual because OPG provided an incomplete explanation	$.299	$.380
½ of the increase for the 2013-14 proceeding as compared to actual for EB-2007-0905 since the latter is the only actual, and not anecdotal basis for comparison	N/A	$.828
Unexplained increase for "other regulatory proceedings" in 2011 as compared to 2009	$1.284	N/A
No basis for assuming OEB annual assessment for 2011 and 2012 will be 50% higher than 2010	$.7	$.7
TOTAL REDUCTION	**$2.283**	**$1,908**

With respect to the first line, Board staff justifies this reduction stating "because OPG provided an incomplete explanation." The basis for this claim is that Mr. Staines, the witness testifying on all aspects of the overall Corporate Affairs budget, explained that the level of support provided by Regulatory Affairs had increased, but was unable to provide a specific figure for the increase in Regulatory Affairs' headcount while under cross examination (Board staff argument, p. 72).

Given his apparent dissatisfaction with Mr. Staines' response, Board staff counsel could have sought additional detail in this area by way of an undertaking, as he did in many other areas, but he did not. Furthermore, if Board staff regarded this single figure as crucial to its understanding of Regulatory Affairs costs, it is difficult to understand why it did not pose this question during its cross examination of Mr. Barrett, who is in charge of the Regulatory Affairs function. OPG submits that this hearing itself amply demonstrates the increasing demands placed on its Regulatory Affairs function and, as a result, Board staff's proposed 50 per cent reduction is completely arbitrary and should be rejected.

With respect to the second line, Board staff has determined to recommend that OPG's forecast increase in hearing costs be cut in half. It offers no justification for arbitrarily cutting the requested increase in half. In fact it offers no reason at all for rejecting the sworn testimony of OPG's witness that legal cost, for this proceeding are tracking to the 2010 budgeted amount. OPG submits that since the legal budget for 2012 is exactly the same as for 2010, Mr. Staines' testimony conclusively establishes the reasonableness of the 2012 request that staff challenges. Similarly, staff simply dismisses the forecast increase in intervenor costs without comment, even though it quotes the cogent explanation for this increase provided by OPG's witness (Board staff argument, p. 72). Anybody in a position to compare the level of intervenor involvement in this application to that in the first application would be hard pressed to disagree with Mr. Staines' comments that this activity has markedly increased.

With respect to the third line, OPG is mystified as to how Board staff can discuss OPG's proposal for a an IRM proceeding or the coming OPA Integrated Power System Plan proceeding elsewhere in its argument and then claim here that OPG is forecasting an "unexplained" regulatory proceeding in 2011.

Finally, the fourth line claims that there is no basis for assuming that the OEB assessment for 2011 and 2012 will be 50 per cent higher than the 2010 assessment. Actually, there is. The OEB assessment has two components, the annual assessment that the OEB charges applicants based on their allocated share of the three-year rolling average of OEB activity. The three-year period forming the basis of the OEB's 2011 assessment will include two main payment amounts proceedings (2010 and 2008) as well as a motion to vary proceeding and an accounting order proceeding in 2009. Clearly, OPG's relative share of OEB activity is going to increase based on this record. In addition, the OEB charges each applicant for the direct cost of consultants that Board staff engages to assist in their review ("Section 30 costs"). OPG has not received any invoices for these costs in 2010, and so it did not include them in its response to Undertaking J9.9, but based on the RFPs that staff issued for consultants in this proceeding, OPG expects a significant increase over the $223k dollars it was charged in the last application. However, only the OEB itself is currently in a position to know the exact amount of the increase.

Based on the foregoing argument, OPG submits that there is no basis for any reduction in its proposed Regulatory Affairs budget.

5.5 CCC'S PROPOSED REDUCTIONS IN CORPORATE SUPPORT COSTS

CCC argues that actual Corporate Support costs have been historically below budgeted amounts and claims to find this "troubling" (CCC argument, p. 30). As a result of these costs being historically below budget, CCC recommends that the test period amount of allocated corporate support costs be reduced by a total of $27.2M. This amount is based on the average variance over 2007-2009.

OPG has two responses. First, OPG is frankly surprised that CCC finds the successful implementation of corporate cost savings initiatives troubling. These initiatives are described in OPG's evidence and include OPG's decision to defer its payment amounts application from 2010 to 2011 (Ex. F3-T1-S2, p. 2, p. 4). OPG would have thought that CCC should welcome the success of these initiatives. This is particularly true because these initiatives have allowed OPG to propose extremely low rates of growth in allocated corporate support costs during the test period. Overall, under OPG's proposal, allocated support costs increase by an average of 1.2 per cent a year over the test period (Ex. F3-T1-S2, Tables 1 and 2). This extremely low rate of growth, less than inflation and much less than OPG's anticipated rate of wage increases, demonstrates OPG's continuing commitment to controlling corporate costs.

Second, as explained above in Section 5.3.1, Employment Levels, CCC's argument is fundamentally at odds with future test year ratemaking. OPG can only imagine the outcry from CCC if OPG attempted to justify a spending proposal solely on the basis that actual expenses had exceeded the amount budgeted for a given category in the last application and proposed that future costs should be increased based on the average amount that prior period costs exceeded budget.

5.6 ASSET SERVICE FEE

Issue 6.12 - Are the asset service fee amounts charged to the regulated hydroelectric business and nuclear business appropriate?

No party objected to OPG's forecast asset service fee amounts. As such, and for all the reasons set out in its evidence and AIC, these amounts should be accepted by the OEB as filed.

6.0 OTHER OPERATING COSTS

> **Issue 6.11** - Are the amounts proposed to be included in the test period revenue requirement for other operating cost items, including depreciation expense, income and property taxes, appropriate?

6.1 DEPRECIATION AND AMORTIZATION

Depreciation Expense and Proposed Depreciation Study

Board staff concludes that depreciation expense may be overstated for the 26 per cent of nuclear facilities that have not been reviewed by the Depreciation Review Committee ("DRC") (Board staff argument, p. 75). Board staff makes this inference based on the increase in useful lives of assets that are part of the nuclear station infrastructure in the 2009 DRC report, despite the fact that when the proposition was put to OPG's witness, he specifically stated that the remaining assets are very different in nature and it is unlikely that their service lives would be increased (Tr. Vol. 10 p. 178):

> MR. MILLAR: So for the remaining 26 percent of nuclear assets, is there any reason we should expect that we won't find more asset lives being extended than being reduced?
>
> MR. BELL: Of the remaining assets to be covered, they're generally the minor fixed asset classes, and they usually don't have a big potential change in life. Service equipment I mentioned, being one of the bigger categories, has a life of ten years.
>
> So it would be most unlikely that it would vary much from that. Service equipment seems to have relatively limited life, and there is not as much room to change for that type of category.

As this evidence shows, there is no basis for the suggestion that depreciation expense is overstated. Further, based on basic regulatory accounting principles, if depreciation expense is overstated then rate base is understated. Yet, nowhere in its argument does Board staff indicate that rate base may be understated because OPG has over-depreciated it. In fact, Board staff argues the complete opposite – that rate base is being overstated (Board staff argument, pp. 19-20). OPG rejects the proposition that either depreciation expense or rate base is overstated and notes that this is a clear example of the one-sided approach Board staff has taken in argument.

Board staff also clearly did not understand that the majority of OPG's nuclear asset class lives are capped by the station lives to which they are relate, even if it is determined that they could in theory last beyond the station's end-of-life date (Ex. F4-T1-S1, p. 3). As such, the extension of asset class lives that was recommended in the 2009 DRC report largely followed the extension of the Darlington end-of-life date to 2051. In fact, the determination of whether individual asset could last until 2051 was an explicit objective of the 2009 DRC (Ex. F4-T1-S1, Attachment 1, p. 6). Where it was determined that an asset class could last the additional length of time required to reach 2051 (e.g., class 15200000 "Buildings & Structures per Appendix C of the 2009 DRC report), the life was extended. Based on the foregoing, Board staff's "expectation" that the outcome of OPG's future reviews of assets is biased toward asset class extensions is wrong.

Board staff goes on to recommend that OPG conduct an independent depreciation study for its regulated assets and the Bruce stations, noting that other large utilities regulated by the OEB have conducted such studies. This proposal is supported by SEC. OPG submits that such a study would increase OPG's costs without providing any value and should not be required.

OPG's prescribed assets are unlike those of other regulated utilities. The major components of the regulated hydroelectric and nuclear stations are unique to those facilities and cannot readily be benchmarked against other utilities or against a large number of similar assets within OPG. Gannett Fleming, the same consultant that is employed by a number of other utilities, including Enbridge (see for example, RP-2002-0133), reviewed OPG's depreciation review process (Tr. Vol. 10, p. 169) and explicitly addressed this difference:

> While statistical analysis of retirement data and benchmarking are other common methods for depreciation reviews used by energy companies, electricity generation utilities tend to have specialized, location specific economic asset life considerations and thus tend to have limited retirement experience that is meaningful to facilities at other locations, either within the company or at other electricity generation companies. This has particular relevance to OPG's

> nuclear assets, which are operated using CANDU nuclear technology. (Ex. F4-T2-S1, page II-6, EB-2007-0905)

Utility depreciation studies use actuarial methods to analyze the lives of retired utility assets. They use this information to the predict future lives of similar existing and potential future assets. The methodology is based on the premise that the utility or other similar utilities have a large number of similar assets and have maintained data on their service lives in their accounting records. For example, electric distribution companies can have tens of thousands of similar hydro poles and gas distribution companies might have thousands of kilometres of gas pipe.

In situations where the utility does not have a large number of similar assets, the estimate of asset lives is based on engineering and economic forecasts of their future use. This is exactly the analysis OPG undertakes in assessing depreciation lives as explained in, its 2009 DRC report (Ex. F4-T1-S1, Attachment 1). Had OPG engaged an external consultant to carry out a depreciation study, the consultant would have used the same methods that OPG staff used in preparing the DRC report and relied on OPG staff for the technical evaluations (e.g., remaining life of pressure tubes at nuclear stations).

In their review in EB-2007-0905, Gannet Fleming recommended "benchmarking of average service lives for certain generation assets to a peer group of utilities as part of the DRC process" (Ex. F4-T2-S1, p.III-1, EB-2007-0905). Given the nature and wide-spread use of certain hydroelectric assets, comparative data from other utilities can be more readily used to support determination of service lives. For example, OPG used benchmarking data in its 2009 DRC report (Ex F4- T1- S1, Attachment 1, p. 8) in the assessment of, and change to the life of the Hydroelectric Outdoor Structures class.

For nuclear assets, Ex. L-01-112 states that reliance must be placed on OPG's own in-depth technical expertise and operational experience because of differences in the design and vintage of CANDU reactors across Canada and the world and particularly because OPG is the "lead" utility in terms of the age of its reactors. With respect to the Bruce assets, OPG explained in Ex. L-01-116 that there are limitations to its ability to access information regarding the conditions of the Bruce assets pursuant to OPG's obligations under the Lease Agreement. As such, an external depreciation study of these assets is particularly unlikely to yield meaningful results.

In its overall assessment, Gannett Fleming specifically noted that “the DRC process adequately meets the regulatory intention for companies to maximize the use of internal information and processes without burdening the ratepayer with significant costs associated with the implementation of new systems or processes.” (Ex. F4-T2-S1, p. II-8, EB 2007 0905).

To require OPG to hire a consultant to perform a study that would end up relying mostly on OPG’s experts and their technical analysis would increase costs for ratepayers and produce little, if any, benefit because it would largely duplicate OPG’s current process. Accordingly, for all the reasons cited above, OPG submits that a depreciation study should not be required.

Pickering

Energy Probe and GEC propose changes to Pickering station end-of-life dates for depreciation purposes. Energy Probe submits that the OEB should revise the end-of-life date for Pickering A from 2021 but does not recommend an alternative date (EP argument, para. 111). GEC submits that the end-of-life dates of Pickering A and Pickering B should be aligned at either 2014 or 2019/2020, depending on the OEB’s decision with respect to Pickering B Continued Operations (GEC argument, p. 42).

Both of these arguments ignore OPG’s evidence that consistent with GAAP, OPG does not revise its end-of-life dates for depreciation purposes until it has a high degree of confidence as to what the revised dates should be (Ex. F4-T1-S1, p.7; Tr. Vol. 10; pp. 75). While OPG anticipates having high confidence to determine an end-of-life decision for the Pickering site in 2012, there are many possible outcomes from the technical analysis and investigation included in the Pickering B Continued Operations initiative that could result in dates other than 2014, 2020 or 2021 (J10.11, p. 3). Assuming new end-of-life dates for ratemaking purposes now would therefore be premature. It would also potentially introduce unnecessary volatility in depreciation expense and other elements of the revenue requirement (Tr. Vol. 10, pp. 84-86).

OPG submits that given the current confidence level regarding the continued operation of Pickering, the accounting end-of-life dates for Pickering A and B used in OPG's application, which are consistent with the audited values used for external financial reporting, should be retained for rate making purposes. As noted in Board staff's argument (p. 80), establishing end-of-service dates for rate making purposes that are different from OPG's financial accounting "could introduce many complexities in the regulatory process including a lack of comparison to reported audited financial information, financial performance and benchmarking issues."

Darlington

SEC, GEC and EP all argue against approval of the extension of the Darlington end-of-life date to 2051 (SEC argument, para. 6.11.1; GEC argument pp. 41-42; EP argument, para. 112). These arguments all rest fundamentally on their views about what an OEB approval of the Darlington Refurbishment revenue requirement impacts would mean in terms of the project itself and, in the case of GEC and EP, on their general opposition to nuclear generation. To the extent that these submissions relate to views on Darlington Refurbishment, they are addressed in Section 4.8, above. This Section addresses arguments related to the decision to extend Darlington's end-of-life date for depreciation purposes.

The DRC recommended that Darlington's end-of-life date be extended to 2051, effective January 1, 2010 (Ex. F4-T1-S1, pp. 5-6). This decision was based on three main considerations. The first was the OPG Board of Directors' decision to proceed with the Darlington Refurbishment project by moving into the Definition Phase and the Province's concurrence with that decision. The second was the technical assessment by OPG Nuclear engineering staff establishing that the expected end-of-life dates following refurbishment would allow operation until 2051. The third was the DRC's conclusion that it had a sufficiently high level of confidence that the refurbishment project would be executed as planned. This conclusion was based on the extensive technical and economic analysis performed by OPG in arriving at the decision to proceed with the refurbishment and the well-established technical and regulatory processes for refurbishment of CANDU units in Ontario and Canada.

As outlined in J10.9, the DRC's recommendation to extend the life of Darlington to 2051 complies with GAAP, has been determined to be appropriate by OPG's external auditors, is reflected in OPG's consolidated financial statements for 2009, and is consistent with OPG's determination that the costs incurred with respect to refurbishment should be capitalized effective January 1, 2010.

Energy Probe asserts that it is unreasonable to believe that the Darlington station will operate until 2051 (EP argument, para. 112). They offer no specific basis to challenge this date, other than their views on the history of nuclear projects and their general opposition to nuclear power. These do not provide an evidentiary basis on which to overturn the decision of the DRC.

GEC argues that since, in their view, approval for the Darlington Refurbishment project is limited to the definition phase; it is premature to extend the life of the facility. As discussed above in Section 4.8, the evidence is clear that OPG's Board has decided to proceed with the Darlington Refurbishment project and this decision has been concurred with by the Province. The fact that the project will be undertaken in specific phases in no way diminishes the reasonableness of the DRC's view that the refurbishment will be executed as planned.

OPG submits that the decision of the DRC to extend the life of Darlington to 2051 for depreciation purposes was reasonable and should not be overturned.

6.2 TAXES

Income Tax

No intervenor objected to OPG's forecast of the 2011 and 2012 tax provision. The sole comment with respect to OPG's test period tax expense was provided by SEC in their submissions on the Tax Loss Variance Account (SEC argument, paras. 10.2.105-109). SEC submits that as a result of unutilized tax deductions, the test period tax provision for 2011 and 2012 should be adjusted to nil. OPG does not agree with SEC's calculation and their proposed application of unutilized tax deductions. OPG addresses these issues in Section 11.1, Tax Loss Variance Account.

Property Tax

No intervenor objected to OPG's forecast property tax amounts and as such, and for all the reasons set out in its evidence and AIC, these amounts should be accepted by the OEB as filed.

HST

Board staff submits that OPG should decrease OM&A by $1M in each of 2011 and 2012 to reflect a revised forecast of the HST savings available (Board staff argument, pp. 77-78). This reduction is not warranted because it is inconsistent with the manner in which commodity tax is incorporated into OPG's test period revenue requirement.

To illustrate the impact of input tax credits for the recoverable portion of HST, OPG's pre-filed evidence provided an estimate of $5M/year for the net savings related to HST. In response to the technical conference question, OPG provided an updated annualized estimate of $6M (JT1.9). At the hearing, OPG noted that July might be a month with higher than average costs resulting in higher than average HST savings. This was confirmed by reference to the actual figures for August and September (Tr. Vol. 15, p. 83; J15.1). As a result of month to month differences, an estimate based on three months of actual data is unlikely to be representative of a full year.

There is no entry for commodity tax in OPG's revenue requirement; rather it forms part of the expenditure on the underlying items (e.g., OM&A, capital inventory, etc.) (Ex. F4-T2-S1, p. 23). Therefore, the difference between the estimate of annual HST savings of $5M in the pre-filed evidence and the estimate of $6M in J15.1 cannot be directly translated into a $1M revenue requirement reduction. Increases in HST savings only occur as a result of increases in the underlying costs attracting the tax. That is, OPG does not obtain greater HST savings unless there are greater expenditures that are subject to HST. With a forecast test year, OPG is held to its forecast of expenditures. Thus it would be inappropriate to isolate the tax effect of changes in expenditures without considering the changes in the underlying expenditures themselves which would be much greater than the reduction in OM&A due to HST. However, Board staff has not proposed any increase in OPG's expenditures. As such, OPG submits that Board staff's suggestion of a reduction to OM&A to reflect increased HST savings should be rejected.

Board staff also submits that OPG should report back to the OEB in its next application with details on its HST returns and the input tax credit amounts related to the prescribed facilities. The requested information will not be meaningful because the input tax credit amounts shown on OPG's HST returns do not necessarily translate to actual HST savings.

To determine actual HST savings, OPG would have to calculate PST and GST on all purchases from July 1, 2010 to December 31, 2010, as if HST had not been implemented and then compare this to the HST cost for that period. This would be a difficult and labour intensive exercise, and OPG submits, not justified by the amounts involved. Furthermore, any report would be complicated by the fact that the information would apply to OPG as a whole (both the regulated and unregulated facilities) and would require an allocation to determine the amount applicable to the regulated facilities.

Board staff further suggests that such a report could be used to validate OPG's compliance with the Minister's request in his May 5, 2010 letter (Ex. L-04-001, Attachment 1). With respect, OPG submits that the adequacy of OPG's response to a shareholder request is matter between OPG and its shareholder and is not for the OEB to "validate."

6.3 PENSION AND OPEB COSTS

In this section OPG replies to submissions on the forecast pension and other post employment benefits ("OPEB") expense for the test period and OPG's request for a Pension and Other Post Employment Benefits Cost Variance Account. The following specific issues are addressed:

- The use of the accrual versus the cash method in determining pension/OPEB expense
- Approval of the Pension and Other Post Employment Benefits Cost Variance Account
- The proposal for a "segregated fund" for OPEB costs

- The impact of changes in the forecast pension/OPEB expense on tax
- Selection of discount rates

Accrual versus Cash Method of Determining Pension/ OPEB Expense

Board staff's submission, introduces a new proposal that OPG's pension and OPEB costs should be recovered on a cash rather than an accrual basis (Board staff argument, pp. 97-99). CME, CCC and SEC support Board staff's submission on this issue (CME argument, para. 238; CCC argument, para. 152 and SEC argument, para. 10.6.2).

The OEB approved the use of the accrual method of determining OPG's pension and OPEB expense in EB-2007-0905. There was no suggestion from any party in that proceeding that OPG should consider the cash method. Similarly, in the present proceeding no party introduced any evidence, expert or otherwise, that OPG should use the cash method for determining pension/OPEB expense. While Board staff asked a few questions in the level of cash payments (Tr. Vol. 10, pp. 190-191), Board staff's proposal to use the cash method was only introduced in argument. Since OPG's witnesses had no opportunity to respond to a proposal to move to the cash method at the hearing, the implications of adopting the cash method have not been fully considered. For this reason alone, Board staff's proposal should be rejected.

The primary rationale for Board staff's proposal is that the cash method "is far more stable over a multi-year period than the erratic nature of OPG's year-end accounting estimates." They base this conclusion on a table of various pension/OPEB costs (Board staff argument, p. 98) that was never presented to witnesses and has not been confirmed as correct or representative of the general case. In fact, there is a major error in the table. The Contributions and Payments in lines 4, 8 and 12 that purport to show the stability of cash pension and OPEB amounts do not reflect the updated pension contributions for 2011 and 2012 provided by Mercer (Ex. H1-T3-S1, Attachment 1, Appendix B). The cash amounts (regulated portion) for total pension and OPEB would be $450.2M in 2011 and $494.5M in 2012, rather than $281.6M in 2011 and $286.9M in 2012 as presented in Board staff's table.[39]

When the correct values are used for the cash contributions and payments in the test period it is clear that the cash method is no more stable than the accrual method. In fact, when the OEB approved Union Gas moving from the cash method to the accrual method in RP-1999-0017 it stated that "There was limited opposition to this change and further, in the Board's view, this may remove some potential variation in this expense" (Decision with Reasons, RP-1999-0017, July 21, 2001, p. 69). This conclusion is logical based on the factors that may cause significant variations in pension contributions in light of the funding valuations required pursuant to the *Pension Benefits Funding Act* (Ontario). OPG's evidence is that the next funding valuation will be performed in 2011 (Ex. F4-T3-S1, p. 17) and depending on the funding status, there may be a future requirement to file annual valuations, as noted by Mercer in Ex. H1-T3-S1, Attachment 1, Appendix B.

SEC states that regulating pension and OPEB costs on a cash basis would result in a treatment that is the same as most utilities regulated by the OEB (SEC argument, para. 10.6.3). SEC provides no support for this proposition and OPG does not accept it. As cited above, Union Gas is regulated on an accrual basis for both pension and OPEB. Hydro One's OPEB costs are regulated on an accrual basis (EB-2009-0096) as are those of many LDCs (e.g., Toronto Hydro, EB-2009-0139). As noted in the "Report on the Transition to International Financial Reporting Standards" prepared by KPMG for the OEB in EB-2008-0408 (p. 73), "current mechanisms allow rates to be set either on a cash or an accrual basis."

While OPG acknowledges that a number of utilities regulated by the OEB use the cash method, the proposal to require OPG to use the cash method to determine pension/OPEB costs is untested and based on an erroneous analysis. OPG submits that it should be rejected and OPG should continue to use the accrual method for determining pension/OPEB costs in the test period.

---

[39] The regulated portion of the updated estimates of total OPG cash payments for 2011 is $374.7M for pension + $75.5M for OPEB and for 2012 are $413.7M for pension + $80.8M for OPEB. The regulated portion of the updated cash amounts has been determined on the same basis as used in L-01-085.

In the event that the OEB determines that OPG's pension and OPEB costs should be determined on a cash basis for ratemaking purposes, OPG's request for the Pension and Other Post Employment Benefits Cost Variance Account would remain unchanged. A variance account is required for recovery of costs on a cash basis because, as noted above, OPG is forecasting a significant variance in its test period cash amounts over those presented in its pre-filed evidence and further changes may arise in subsequent funding valuations, particularly if OPG is required to move to annual valuations, while continuing to use a multi-year test period for setting the payment amounts.

Proposal for a "Segregated Fund" for OPEB Costs

Board staff submits that under the accrual method, the OEB should consider a segregated fund to deal with the differences between the amount collected in rates and the cash OPEB payments made by OPG (Board staff argument, p.99). OPG supports the submissions of SEC in disagreeing with this request on the basis that any segregated fund would have to address situations when accrual costs were both higher and lower than cash costs (SEC argument, para. 10.6.5). In addition, OPG submits that it is doubtful whether the OEB has the jurisdiction to mandate OPG to set cash payments aside in a segregated fund for a specific use. Board staff's argument is silent on this question as well as on how such a fund would be structured, managed and paid for. Finally, at least for the supplementary pension plan component of OPEB, there likely would be adverse tax consequences to OPG under the *Income Tax Act* that would have to be passed on to ratepayers, if the OEB required such an arrangement. For all of these reasons, the proposal for a segregated fund for OPEB costs should be denied.

Approval of the Pension and Other Post Employment Benefits Cost Variance Account

In its Impact Statement (Ex. N-T1-S1), OPG provided updated forecasts of its pension and OPEB costs for 2011 and 2012 as projected by external actuaries as of the end of August 2010. Compared to OPG's original evidence, the total projected increase over the two test years is $251.5M for Nuclear and $12.7M for Regulated Hydroelectric

(Compare Ex. F4-T3-S1, Chart 9 to Ex. N-T1-S1, p. 3).[40] The change in forecast pension/OPEB costs is primarily a result of changes in estimates of discount rates and pension fund performance. OPG identified that it is possible that there will be further significant variability before actual costs are known (Tr. Vol. 15, pp. 101-102). To address this variability, OPG requested the approval of a Pension and Other Post Employment Benefits Cost Variance Account (Ex. H1-3-1, p. 9).

Board staff has argued that the requested account should not be approved. Its submissions are supported by CME, CCC, SEC and VECC. Board staff provides three arguments in support of its position – first, that the increase in costs has not been discussed with OPG's shareholder; second, had the account that OPG requested and was denied in EB-2007-0905 been approved, the balance in that account would offset forecast increases; and third, based on the experience of Hydro One Transmission, the amounts in question are not likely to be material. OPG addresses each of these arguments below.

First, Board staff submits "that if $264.2M is not material enough [for OPG] to discuss with its shareholder, OPG should not be requesting a variance account" (Board staff argument, p. 99). In response, OPG would observe that the matters that OPG discusses with its shareholder is a decision that properly rests with OPG's management and not Board staff. Further, the requirement for a utility to have shareholder approval before applying for a variance account has never been part of the Board's assessment of the merits of a variance account proposal. In OPG's submission, there is no reason to introduce this requirement now as it is not relevant to the determination that the Board must make with respect to the proposed account. Further, to suggest that $264.3M is not a material amount is unreasonable on its face.

Second, Board staff estimates that OPG will over-recover pension/OPEB costs for the 2008-2010 period and that this over recovery should be considered as an offset to increases in forecast costs in the test period. This is retroactive ratemaking. Rather than addressing the prudence of forecast test period costs, Board staff proposes to reach

[40] These figures do not include any offsetting tax savings associated with the deductions for the anticipated increase in pension plan contributions that OPG would include as a credit to ratepayers in the proposed variance account (Ex. H1-T3-S1, page 11).

back to prior period costs and average them with forecast test period costs to determine the amount, they say, is properly included in rates for the test period. This is exactly the type of action that the prohibition against retroactive ratemaking is intended to prevent.

Further, Board staff's second argument attempts to "redo" the decision of the OEB in EB-2007-0905. In that proceeding, the OEB rejected OPG's request to create a variance account for pension and OPEB costs (Decision with Reasons, EB-2007-0905 p. 127). Now, having seen that the account would have been in ratepayers' favour, Board staff is proposing to capture the benefit of the balance that would have been in the variance account had the OEB approved its creation.

Finally, the numbers put forward by Board staff as part of their second argument are not correct. Board staff has conducted an analysis that is not consistent with the evidence and it was not put to the witnesses for verification. The calculation uses the entire year for 2008 rather than reflecting the fact that the effective date of payment amounts from EB-2007-0905 was April 1, 2008.

More significantly, Board staff's argument grossly over estimates the difference between budget and actual costs in 2010. Board staff states that there is insufficient evidence to determine the 2010 actual costs, but assumes the difference between budget and actual is the same as 2009 (notably they do not use the 12/21 proration to annualize the 21-month test period costs which would have been significantly lower than the 2009 costs). In fact, the projected 2010 values for actual pension and OPEB costs were provided in response to Board staff interrogatory L-01-084. The total OPG pension and OPEB cost for 2010 is $334M (L-01-084 Attachments 2 and 3),[41] which results in an allocated cost of approximately $260M to the regulated facilities.[42] This value is essentially the same as the 2010 budget of $258M (Ex. F4-T3-S1, p. 25). Therefore, Board staff's estimate that actual costs were $143M less than budget is significantly wrong. OPG acknowledges that the information in L-01-084 is complex but having requested it in an interrogatory,

[41] Registered Pension Plan costs are $125M (L-01-084 Attachment 2, page 3) and OPEB costs include Supplementary Pension Plan costs of $20M (L-01-084 Attachment 2, page 3) plus Post-Employment Benefits of $32M and Non-Pension Post Retirement Benefits of $157M (L-01-084 Attachment 3, page 4).
[42] The allocation to the regulated facilities is based on the methodology set out in Ex. F4-T3-S1, page 24, section 6.3.3.

Board staff should have put questions on 2010 pension and OPEB costs to OPG's witnesses rather than presenting new and incorrect calculations in argument.

In its third argument, Board staff reports on the small variances that Hydro One Transmission has recorded in its Pension Cost Differential Account and infers that OPG will also record immaterial amounts. However, there is no basis for the suggestion that the variances that OPG will experience in the test period are likely to be immaterial. Board staff also ignores OPG's evidence that based on actuarial estimates, OPG's updated forecast shows an increase in pension/OPEB costs of $264.3M for the test period.

VECC attempts to distinguish a number of cases in which the OEB has approved pension variance accounts as inapplicable to OPG (VECC argument, paras. 129-135). Before disputing VECC contentions with respect to the precedents that it cites, OPG will address the precedent that it believes to be most relevant to its request, which VECC ignores. In EB-2009-0096, which is referenced in OPG's request for approval of the Pension and OPEB Cost Variance Account (Ex. H1-T3-S1, p. 10), the OEB approved a Pension Cost Differential Account for Hydro One Networks Inc. (EB-2009-0096, April 9, 2010, pp. 56-57).[43] This Decision states that the purpose of this account is "to track the difference between the actual pension costs booked using the actuarial assessment provided by Mercer, and the estimated pension costs used in this filing." (EB-2009-0096, p. 56). OPG submits that the account approved for Hydro One mirrors the account that OPG is requesting and there are no unique circumstances that would justify approving this account for Hydro One and denying it for OPG.

VECC reviews a number of OEB Decisions which have approved pension/OPEB variance accounts (RP-2004-0180/EB-2004-0270, EB-2006-0501, EB-2007-0681) and argues that they are not relevant. The premise of VECC's argument is that the actual account that Hydro One Networks Inc. ("HONI") has been authorized to use to record the above-noted difference had its origins in "very specific and unique circumstances" dating back to 2004 (VECC argument, para. 129). This leads VECC to conclude that the Board "never actually turns its mind to the appropriateness of allowing HONI to be fully

[43] That VECC fails to mention this precedent is surprising, given that the OEB's decision notes that VECC supported the creation of the account that Hydro One requested (EB-2009-0096, page 57).

protected from the risk associated with pension cost forecasts." VECC further claims that the Board failed to recognized that "the Transmission pension deferral account was granted without recognizing any acceptance that the amounts tracked were recoverable by the utility." (VECC argument, para. 134). OPG disagrees based on the record in EB-2009-0096.

In that proceeding, the record shows that the OEB did turn its mind to question of whether it was appropriate to permit the above-cited variances to be tracked in a variance account because it rejected SEC's argument against the inclusion of the variance arising from HONI's pending pension fund valuation in the account. The Board went on to say: "The Board accepts that the impact of the actuarial assessment could be significant and notes that the issues identified by SEC and AMPCO can be addressed at the time of disposition" (EB-2009-0096, Decision with Reason, p.57). The fact that the OEB noted that the parties were free to dispute the appropriate amount to be recovered at the time of disposition, demonstrates only that this variance account, like all others, was subject to a prudence review upon clearance. OPG submits that there is no basis on which to distinguish the circumstances that gave rise to the Hydro One variance account from the circumstances that exist here.

Board staff submits that if the OEB grants the requested account, it should not record variances in OPEBs and supplementary pension plan costs. There is no basis for this submission. The discount rate fluctuations that affect registered pension costs affect OPEB and supplementary pension costs in exactly the same manner. All of the criteria that justify the request for a variance account, i.e., materiality, inability to forecast and matters outside of management's control, apply equally to registered pension, OPEB and supplementary pension costs.

OPG agrees with Board staff in one regard and that is "There is no question that over the long-term OPG must recover its prudently incurred costs, including pension and OPEB costs." (Board staff argument, p. 98). OPG has provided detailed evidence, in the form of an independent actuarial estimate that its forecast test period cost have increased by a material amount. There is no suggestion that these pension/OPEB costs will not have been prudently incurred. Consistent with the OEB's determination in EB-

2007-0905 that: "In the event that OPG's actual pension and OPEB costs during the test period are materially in excess of the amounts included in the revenue requirement, OPG would have the ability to apply to the Board" (Decision with Reasons, EB-2007-0905, p. 127), OPG submits that its request for a Pension and Other Post-Employment Benefits Cost Variance Account should be approved.

If the OEB were to reject the requested variance account, OPG's revenue requirement for the test period should incorporate the most up to date estimates of its test period pension and OPEB costs, whether on an accrual or a cash basis. The Impact Statement provides an estimate of these costs for the prescribed assets as of August 31, 2010 (Ex. N-T1-S1, page 3). In the section above on the cash versus accrual method of recovery, OPG provided the amount of updated cash costs for the prescribed assets, based on the actuarial assessment underlying the Impact Statement.

The impact of changes in the forecast pension expense on tax

Board staff states that the forecast increase in accrual pension and OPEB costs for the test period "have not been identified by OPG to cause any income tax expense consequences." (Board staff argument, p. 96). This is not correct. The consequences are explicitly identified in the evidence for the Pension and Other Post Employment Benefits Variance Account (Ex. H1-T3-S1, p. 11):

> In addition to the differences between forecast and actual pension and OPEB costs, there is expected to be a difference between forecast and actual regulatory tax deductions for pension plan contributions and OPEB benefit payments. As OPG expects its pension plan contributions to be higher than those included in the application, capturing this difference in regulatory tax deductions in this account will partly offset the expected increase in pension and OPEB costs. …Accordingly, OPG proposes that the proposed Pension and Other Post Employment Benefits Cost Variance Account also record the difference in the regulatory tax expense resulting from the difference in pension plan contributions and OPEB benefit payments included in determining the tax expense for the prescribed facilities in the OEB-approved payment amounts and the portion of actual pension plan contributions and OPEB benefit payments attributable to the prescribed facilities made by OPG.

Contrary to Board staff's estimation (Board staff argument, pp. 96-97) that "the undisclosed (grossed-up) tax impact is approximately $91.6M for the two test periods (sic)," OPG has indicated that there will be a reduction in tax as a result of the increase in tax deductions associated with increased pension contributions (Tr. Vol. 15, p. 97).

Consistent with the argument above regarding the Pension and Other Post Employment Benefits Variance Account, OPG submits that it is appropriate to include the tax impacts associated with the variance in pension and OPEB costs in the entries in the variance account, as per OPG's proposal.

Selection of Discount Rates

Board staff submits that OPG should provide evidence that discusses other alternatives to its methodology for selection of discount rates used in calculating accrual pension and OPEB costs in accordance with GAAP (Board staff argument, p. 101).[44] OPG uses representative AA corporate bonds to forecast the discount rates to determine the accrued benefit obligation. OPG's use of AA corporate bonds complies with the criteria stated in the CICA Handbook, paragraphs .050 to .054. Furthermore, the use of AA corporate bonds is cited in the Employee Future Benefits Implementation Guide, published by the CICA in 1999. This guide is identified as a primary source of GAAP in paragraph .21 within Section 1100 of the CICA Handbook.

In addition, as the criteria for determining the appropriate discount rate under Canadian GAAP is similar to the criteria under U.S. GAAP, OPG looked to U.S. guidance and noted that on November 16, 2006, the U.S. Securities and Exchange Commission Staff restated their view that the use of fixed-income security that receives a rating of Aa or higher from Moody's Investors Service, Inc. is an appropriate example of a high-quality fixed-income investment that may be used in determining the discount rate.

In summary, based on the evidence from the secondary sources of GAAP, OPG's use of AA corporate bonds to forecast the discount rate is appropriate.

[44] In its argument, Board staff cites Section 3461 of the CICA Handbook at paragraphs .063 to .065 as the source of the definition of the selection criteria for a discount rate. OPG believes that Board staff meant to refer to paragraphs .050 to .054.

6.4 NUCLEAR INSURANCE

Board staff and SEC both argue that the uncertainty associated with passage of the *Nuclear Liability and Compensation Act,* the driver behind OPG's forecast increase in nuclear insurance costs, means that OPG should not be factoring such costs into its revenue requirement. Board staff further suggests that if C-15 does in fact receive Royal Assent, the associated cost increase going forward could be addressed in OPG's next application.

OPG believes that it is appropriate and prudent to budget for an increase in insurance premiums during the test period. OPG establishes an operating budget through the annual business planning process, and it must operate within this budget. One of the hallmarks of this process is that it is, by its nature, relies on forecasts. In these forecasts there are two types of uncertainty related to future expenses: items which are unknown and unforeseeable until they occur and items which are known, but whose timing or cost is uncertain. To the extent that there are operating expenses that are unforeseen when the test period budget is set, these expenses, when they materialize, must be absorbed by OPG and its shareholder. This instance, however, is an example of the second type of uncertainty. OPG is aware of the initiative to increase the limit on nuclear insurance, the initiative is well-advanced (J10.12), and OPG's best estimate is that changes will be forthcoming during the test period (Tr. Vol. 10, p. 155). OPG notes that this is the first hearing at which it is seeking recovery of these expenses even though there have been "numerous other bills that have been introduced by the federal government over the past three years to amend and replace the *Nuclear Liability Act*" (Board staff argument, p.74).

Board staff also cites an example where the Board refused to incorporate, into the calculation of RPP, changes in proposed legislation (Ibid.). The distinction in that case was the existence of a variance account:

> To the extent that there are changes in the Global Adjustment allocation after November 1, 2010, <u>the RPP variance account will capture these changes and the impact will be incorporated into RPP prices later</u>. (RPP Price Report, October 18, 2010, p. 11) (emphasis added).

The ability to capture the impact of changes in future RPP prices means that there is no prejudice to consumers from failing to incorporate proposed regulatory changes. Board staff suggests that for nuclear insurance premiums, the impact of an increase should be addressed at the next application on a going forward basis. Without the existence of a variance account, however, which neither OPG nor Board staff support, Board staff's approach would deprive of OPG the opportunity to recover an appropriate forecast cost.

Finally, Board staff's argues that the amounts involved are likely to be lower than OPG forecasts and, as a result, questions their materiality (Board staff argument, page 75). OPG notes that Board staff's position on materiality here is at odds with staff's position on materiality with respect to HST or Saunders Visitor Centre OM&A.

7.0 BRUCE LEASE COSTS AND REVENUES

Issue 7.3 - Are the test period costs related to the Bruce Nuclear Generating Station, and costs and revenues related to the Bruce lease appropriate?

The revenues and costs associated with the Bruce Lease and associated agreements are calculated based on the OEB's Decision in EB-2007-0905. This decision held that the Bruce Generating Stations should not be treated as if they were regulated assets. As a result, the revenues and costs associated with the Bruce Lease must be calculated in accordance with GAAP. The only issue raised with respect to Bruce Lease costs was the consequent impacts on nuclear liability costs of the change to the Darlington end-of-life date.

GEC argues that the changes proposed to the Bruce Lease costs that flow from OPG's decision to extend the end-of-life date for Darlington to 2051 are not appropriate (GEC argument, p. 43). The end-of-life dates in OPG's Application result in Bruce Lease revenues and costs that are consistent with OPG's actual GAAP accounting information as reflected in its financial statements (J10.11). Bruce Lease revenues and costs that result from a scenario that does not reflect the 2051 end-of-life date for Darlington (discussed above in Section 6.1) are inconsistent with OPG's GAAP accounting information, its published financial statements and the OEB's Decision in EB-2007-0905.

In an exchange with SEC counsel, OPG's witness made it clear that the Board's findings with respect to the appropriate end-of-life assumption for Darlington for ratemaking purposes would not change Bruce Lease costs as determined in accordance with GAAP:

> MR. SHEPHERD: All right. So there is two parts to this question, then. The first part is you're saying for GAAP accounting you're required to assume that you are going to refurbish Darlington anyway, no matter what this Board says. So this 54 million would not be an impact in the current revenue requirement of this Board saying, Let's assume you are not going to do --
>
> MR. REEVE: That's correct. I mean, there's been extensive discussion around Darlington and why we believe it is appropriate in our application to refurbish Darlington.
>
> MR. SHEPHERD: But if this Board said it is premature, right - we don't want to assume that right now - then the correct number in scenario 3 is $191 million, not that additional $54.4 million; right?
>
> MR. REEVE: That's correct, because we follow GAAP for -- that's what's in our application. That was the basis for our application. Bruce is in accordance with GAAP. So we would have to follow the 2051 date, because that is what we're required to do for GAAP purposes. (Tr. Vol. 16, pg. 53).

OPG submits that consistent with the requirement to treat the Bruce assets as unregulated assets, the revenues and costs based on GAAP accounting are appropriate. As such, the Bruce Lease revenues and costs for the test period should be accepted by the OEB as filed.

8.0 COST OF CAPITAL

> **Issue 3.1** - What is the appropriate capital structure and rate of return on equity?
>
> **Issue 3.2** - Are OPG's proposed costs for its long-term and short-term debt components of its capital structure appropriate?
>
> **Issue 3.3** - Should the same capital structure and cost of capital be used for both OPG's regulated hydroelectric and nuclear businesses? If not, what capital structure and/or cost of capital parameters are appropriate in each business?

All parties either accepted or did not oppose OPG's proposed capital structure of 47 per cent equity and 53 per cent debt for its combined regulated operations. The remainder of this section discusses intervenor arguments with respect to the methodology for fixing

OPG's ROE, CME's arguments against the application of the Board's Cost of Capital Report, debt rates and Issue 3.3 above.

With the exception of CME, all parties accepted the use of the OEB's formula for determining OPG's ROE for 2011 based on data three months prior to the effective date of new payments. On OPG's calculation, the 2011 ROE is 9.43 per cent based on November data for payment amounts proposed to become effective March 1, 2011.

8.1 2012 ROE METHODOLGY

For 2012, Board staff and VECC argue that the ROE figure should be updated in 2011 to similarly reflect the Consensus Forecast data three months prior to January 2012. Board staff argues that this update, which would take the form of another application by OPG, could be done on an expedited basis. With respect, OPG disagrees. It is OPG's position that using the Global Insight forecast now to set the ROE is appropriate and consistent with its application. On OPG's calculation, this forecast produces an ROE of 9.55 per cent for 2012.

In essence, Board staff argues that other utilities applying for a two year test period have been ordered to update their cost of capital parameters in the second year and OPG should be treated no differently. However, Board staff's reliance on the Toronto Hydro and Hydro One cases to make its argument is misplaced. In those cases, the utilities had already proposed to amend rates for the second year. Accordingly, requiring changes to the cost of capital parameters made sense. This is not OPG's situation. Here, OPG is seeking a single rate for the entire test period based on a blend of 2011 and 2012 costs, including ROE.

SEC, while recognizing the value of a single rate, argues that the ROE should be based and fixed at the 2011 amount. SEC argues by analogy to incentive regulation. It also expresses concerns relating to reliance on Global Insight data.

SEC's analogy to incentive regulation is inappropriate. Under an incentive framework, the price escalation mechanism is used to adjust for changes in capital costs. Here, OPG has no such escalation mechanism. Further, SEC's concern that the Global Insight forecast has not been sufficiently tested is equally misplaced. As illustrated in Ex. C1-T1-

S2 Table 7a, OPG currently uses the 2012 Global Insight forecast to determine the debt cost rate associated with $600M in new debt forecast to be issued in 2012 (see debt issues 26 and 27 and Niagara issues 19, 20, 21 and 22). In addition, OPG used the Global Insight forecast in EB-2007-0905 for purposes of setting its debt costs (Decision with Reasons, EB-2007-0905, pp. 163-164). The OEB, in that proceeding, did not have any concerns with the use of the Global Insight forecast and approved OPG's debt costs as proposed (Ibid.).

In the event the OEB determines that the Global Insight forecast data should not be substituted for the Consensus Economics data, OPG submits that the OEB should establish a variance account to record the revenue requirement impacts of any differences arising from the ROE approved in rates for 2012 and the 2012 ROE determined using Consensus Economics data from September 2011. This would be a better approach than requiring OPG to file an application for what is likely to be a relatively small to change rates in 2012. Use of a variance account would save on regulatory costs, reduce the burden on the OEB and also eliminate the need for the IESO to institute another rate change in its settlement system at the start of 2012. This approach would also have the benefit of rate stability, valued by intervenors such as SEC.

8.2 APPLICABILITY OF THE OEB'S COST OF CAPITAL REPORT

Based on its faulty business planning and customer impact arguments, CME argues that the OEB should award OPG an ROE that is some, unspecified, amount less than what would result from the application of the OEB's Cost of Capital Report. In support of its position, CME makes the following arguments, each of which is discussed below:

(i) The OEB has the jurisdiction to award an ROE less than the rate that is derived by applying the OEB's cost of capital guidelines;

(ii) The OEB should exercise that jurisdiction in this case as a result of the "overall electricity price" environment; and

(iii) The cost of capital "actually" incurred by the Province is its borrowing cost in the debt markets.

(i) Jurisdiction of the OEB

In making its argument, CME misstates OPG's position. As described in its AIC, an essential component of just and reasonable rates is the requirement to set rates at a level that permits a utility to earn a fair return on its invested capital. This requirement "is not optional; it is a legal requirement" (EB-2009-0084, p. 18). This does not mean, however, that the return must be at a particular percentage level, nor has OPG argued as much.

In its Cost of Capital Report, the OEB established a revised base ROE and a modified automatic ROE adjustment mechanism for <u>all</u> utilities regulated by the OEB making cost of service applications in 2010. As the OEB indicated in its February 24, 2010 letter addressed to OPG, among others:

> "The Board considers these cost of capital parameter values [including ROE] and the relationship between them reasonable and representative of market conditions at this time and for the 2010 rate year.
>
> These values will be applied by the Board in its consideration of 2010 electricity Cost of Service applications."[45]

There is no proper basis to depart from the OEB's cost of capital values in this case, and certainly not for the reasons advanced by CME.

(ii) The overall electricity environment

This argument simply repeats the suggestion that the OEB should deny OPG recovery of its prudently incurred capital costs out of concern for costs over which OPG has no control. For the reasons discussed in relation to Issues 1.2 and 1.3, this argument has no legal merit.

(iii) The Province's cost of capital

CME asserts that the OEB, in setting OPG's ROE, should be guided by its shareholders' cost of capital. This is an astonishing argument given (1) its complete lack of evidentiary

---

[45] EB-2009-0084, letter dated February 24, 2010, pp. 1-2

foundation; and (2) the fact that it was advanced by CME and rejected by the OEB in the last payments case.

On the first point, CME is saying that because the government's cost of capital for its equity investment in OPG is allegedly its cost of debt, that is what the ROE for the investment should be. But this principle, if correct, must be applied equally whether the shareholder's own risk profile or cost of capital is low or high. In other words, if ratepayers are to benefit from having a government shareholder by enjoying a low cost of capital in rates, customers must equally be exposed to higher costs of capital where other utility owners have a high cost of capital. That is not how the OEB, or any other regulatory tribunal, has viewed the determination of an appropriate ROE in any previous proceeding of which OPG is aware. In addition, it is inconsistent with the standalone principle which the OEB accepted in EB-2007-0905 (Decision with Reasons, p. 140).

Besides violating the standalone principle (which the OEB, and all financial experts testifying in this proceeding agreed was applicable) and well-settled regulatory principles, the CME contention violates a basic principle of finance - that the cost of capital should reflect the riskiness of the entity or the project in which the funds are invested, not the source of the funds. The CME position reflects the misconception that the cost of raising capital to invest in a project (the financing decision) is the same as the cost of capital (required return) of the project. Dr. Morin, author of New Regulatory Finance (2006) says:

> "Financial theory clearly establishes that the true cost of capital depends on the use to which the capital is put. Both common sense and financial theory assert that risk-averse investors require higher returns from high risk investments. This implies that the expected return, or cost of capital, for a higher risk investment exceeds that of a lower risk investment. The specific source of funding an investment and the cost of funds to the investor are irrelevant considerations."[46]

Ultimately, it is telling that CME's argument on this point has not been raised, or even mentioned, by any finance expert who testified in this proceeding.

[46] New Regulatory Finance, Roger Morin, Vienna, VA: Public Utilities Reports, Inc., 2006, p.216, as quoted in EB-2007-0905 OPG Reply Argument, pp. 10, 11

On the second point, CME made this very argument in EB-2007-0905, and it was rightly rejected by the OEB. In that case, CME submitted that the OEB should approve a ROE for OPG it considers to be compatible with the costs the government actually incurs to support its equity position in OPG and the ROE the OEB allows to the other Government electricity utilities it regulates."[47]

As the OEB summarized CME's argument and its findings:

> CME submitted that the ROE should be between 5.85% and 8.57% (the most recently approved level for Hydro One), and should be set at the lower end of the range given the acknowledgment by the government in its February 23, 2005 announcement that the 5% ROE ensures a fair return to tax payers. (EB-2007-0905, Decision with Reasons, p. 152)
>
> **Board Findings**
>
> The Board agrees with OPG that it would be inappropriate to set OPG's ROE at 5.85%. This rate does not represent the cost of capital for OPG's regulated facilities; it is the interest rate on OPG's prior debt obligation to the OEFC. The Province may have assumed this debt, but that is related to the shareholder's cost of capital, not OPG's cost of capital. (EB-2007-0905, Decision with Reasons, p.153)

In further support of its argument, CME argues that its proposal would not compromise safety or reliability. This is factually incorrect. As OPG's witnesses testified at the hearing, the revenues associated with OPG's cost of capital go towards funding its operations (Tr. Vol. 12, pp. 128-129; Tr. Vol. 15, pp. 30-32). In any event, even if it were true, it would fail to satisfy the fair return standard. As the OEB's Cost of Capital Report concluded (EB-2009-0084, p. 20), meeting service quality obligations is not synonymous with an adequate return:

> Finally, the Board questions whether the FRS has been met, and in particular, the capital attraction standard, by the mere fact that a utility invests sufficient capital to meet service quality and reliability obligations. Rather, the Board is of the view that the capital attraction standard, indeed the FRS in totality, will be met if the cost of capital determined by the Board is sufficient to attract capital on a long-term sustainable basis given the opportunity costs of capital. As the Coalition of Large Distributors commented:

[47] CME Argument, EB-2007-0905, para. 171

> [t]he fact that a utility continues to meet its regulatory obligations and is not driven to bankruptcy is not evidence that the capital attraction standard has been met. To the contrary, maintaining rates at a level that continues operation but is inadequate to attract new capital investment can be considered confiscatory. The capital attraction standard is universally held to be higher than a rate that is merely non-confiscatory. As the United States Supreme Court put it, 'The mere fact that a rate is non-confiscatory does not indicate that it must be deemed just and reasonable'.[48]

For all of the reasons set out above, OPG submits that OEB should reject CME's argument that OPG should be awarded an ROE less than that provided for under the OEB's Cost of Capital Report.

8.3 SHORT-TERM DEBT

Board staff and SEC both commented on OPG's cost of short-term debt.

Board staff argues that OPG should update its short-term debt rate for 2011 as part of the order finalisation process and then later for 2012 as part of a further application (Board staff argument, p. 6 and p. 12).

With respect to its proposed 2011 update, Board staff relies on the OEB's Cost of Capital Report. However, they ignore the fact that the Board's Cost of Capital Report directs OPG to use the same approach for short term debt that it used in EB-2007-0905 (EB-2009-0084, p. 56) and that, in fact, is what OPG has done. In EB-2007-0905, OPG assessed at the time of its Impact Statement whether there was a need to update its short term debt costs and determined that there was not a material difference in the costs and so no update was required (EB-2007-0905, Ex. N-T1-S1). In this case, OPG also canvassed internally for material changes at the time that it prepared its Impact Statement and only three items, none of which was debt costs, exceeded the $10M materiality threshold that OPG had established (Tr. Vol. 15, pp. 104-105).

Given that OPG has used the same approach for considering an update to its short term debt costs, a method that OEB found acceptable in the last case, and given that OPG

[48] Final Comments of the Coalition of Large Distributors. October 26, 2009. pp. 5-6

did not bring forward other small items that might have caused the revenue requirement to go up, OPG submits that it would be unfair for OEB to now require it to update in short term debt costs for 2011.

Board staff's submissions also ignore the fact that the method approved by the OEB in EB-2007-0905 for setting OPG's short term debt rate is not the same as the method used for electric distributors. OPG's short-term debt cost reflects OPG's specific circumstances and this was the approach accepted by the OEB in EB-2007-0905.

The generic methodology for distributors requires an updating of a generic credit spread between banker quotations and the Bankers Acceptance rate from the Bank of Canada at a point in time. In contrast, OPG's credit spread is a utility-specific forecast for the test period reflecting Bankers Acceptance rates published by Global Insight. As both Bankers Acceptance rates and credit spreads can change over time, it would not be consistent to change the Bankers Acceptance rate, as the generic methodology requires for distributors requires, without changing the related credit spread. That is not how the OEB's short-term methodology works, yet it is what is being proposed by Board staff.

SEC argues that OPG's proposed short-term rate uses an old forecast and should be updated. SEC also states that "updating of debt is more akin to forecasting OM&A and similar costs, whereas updating ROE - i.e., the inputs to a formula established by OEB - is less like that" (SEC argument, para. 3.1.12). OPG agrees with this statement but not the conclusion drawn by SEC. The OM&A spending set out in OPG's application is based on OPG's 2010-2014 Business Plan which was approved by its Board in November 2009. The short-term debt rate in the Application is the same rate used for purposes of the business plan that underpins the Application. There is no need for any update to these rates, just as there is not for OM&A spending, other than through the Impact Statement process.

8.4 LONG-TERM DEBT

Board staff makes no submission on OPG's existing and planned long-term debt costs, noting only that it is consistent with the OEB's Cost of Capital Report. SEC comments that the proposed rates are consistent with the OEB's deemed long-term debt rate established November 15, 2010; concluding that OPG's existing and planned long-term debt rates "are in the ballpark" (SEC argument, para. 3.2.1).

Given that no objections were raised to OPG’s long-term debt forecast, OPG submits that it should be accepted for all of the reasons set out in its evidence and AIC.

8.5 OTHER LONG-TERM DEBT PROVISION

Board staff and VECC argue that OPG should be required to use its actual and planned long-term debt cost for its long-term debt provision. In support of its argument, Board staff relies on a series of cases decided *prior* to the issuance of the OEB's Cost of Capital Report. To the extent older cases have any relevance to this issue, the most important is EB-2007-0905 which was not cited by Board staff. In that case, the OEB determined that "it is appropriate to use the average of the hedged cost of planned debt" to calculate the cost of OPG’s other long-term debt provision (EB-2007-0905, p. 164).

In contrast to the situation with respect to short-term debt where OPG-specific direction was provided, the Cost of Capital Report was silent on the costing of OPG's Other Long-Term debt provision. However, it does provide guidance to electric distribution utilities that OPG believes is relevant to the calculation of its other long-term debt provision rate. In the Cost of Capital Report, the OEB discusses the use of a deemed debt rate for utilities with no actual debt. And it determines that the appropriate cost for this type of debt is a forecast rate (Cost of Capital Report, Appendix C). The use of a forecast rate cost for notional debt in the Cost of Capital Report is also consistent with the OEB’s decision in EB-2007-0905 for OPG’s other long term debt provision. In EB-2007-0905, the OEB approved the use of a forecast rate related to future debt, not one based on an average of old, historical debt.

As new debt is issued to displace the Other Long-Term Debt provision it will be issued at future debt rates. Accordingly, OPG submits that a forecast rate based on future issues for the test period better reflects OPG's opportunity cost of capital. Unlike the majority of electricity distributors, OPG has an active long-term borrowing program; therefore it is not necessary to rely on the cost of historic debt (which has no relation to the cost of borrowing/opportunity cost of capital in the test period) as a proxy for future, incremental debt costs.

8.6 CAPITAL STRUCTURE

Ratepayer groups universally do not support setting separate capital structures for OPG's hydroelectric and nuclear technologies. CCC, CME, AMPCO, VECC and SEC all argue that the evidence in support of such structures is not sufficiently robust and the benefits are, at best, marginal. SEC's position is particularly telling, given that it was a proponent of separate capital structures in the last payments case.

SEC makes a number of good points in setting out its position, noting that OPG raises funds on a company-wide basis (SEC argument, para. 3.3.8), that approving technology-specific capital structures might prompt others to apply the same logic to the different assets of other utilities (Ibid., para. 3.3.12), and there is no value in the price signal since there is no ability to change anyone's behaviour (Ibid., para. 3.2.21).

For its part, Board staff takes no position, stating simply that the "The Board Panel must consider whether the evidence on the record, whether derived from econometric analysis or based on expert judgment, is sufficient to distinguish and, if so, to estimate technology-specific costs of capital with sufficient confidence that any technology-specific estimates are adequately supported" (Board staff argument, p. 15).

Only Pollution Probe, GEC and Energy Probe argue for technology-specific capital structures. The principal argument advanced by these parties is an alleged improvement in allocative efficiency. This benefit is illusory, and will add unnecessary complications to future applications by OPG and other regulated utilities.

1. As a result of the operation of the IESO market, consumers do not buy power from any particular producer, let alone based on generation type and the price they pay does not distinguish allowed rates of return for different technologies.

2. The alleged difference between the equity ratios applicable to the regulated hydro and nuclear operations, and the resulting returns, is small (Tr. Vol. 12, p. 127, lines 14-24).

3. Project specific risks are already incorporated into OPG's assessment of project cash flows, which OPG testified represent a more robust methodology than simply applying separate costs of capital (Tr. Vol. 12, pp. 71-72; Tr. Vol. 12, p. 73, lines 7-21).

There are no compelling reasons for the OEB to accept the recommendations of Drs. Kryzanowski and Roberts. Contrary to the submission of Pollution Probe, GEC and Energy Probe, Drs. Kryzanowski and Roberts did not build upon or extend the analysis they had done in EB-2007-0905. Rather, they employed the same heuristic methodology. Not surprisingly, they reached substantially the same conclusions (Tr. Vol. 12, pp. 163-165). The OEB in the last case was not satisfied with the robustness of their methodology, nor should this panel be.

Drs. Kryzanowski and Roberts did observe that they had employed the same methodology in testimony before the Alberta Utilities Commission ("AUC") but failed to identify that they had done so unevenly (Tr. Vol. 12, p. 163). In this respect, their own analysis indicates that if the OEB were to implement technology-specific capital structures, the equity ratio for regulated hydroelectric should be 45 per cent, equal to the ATCO Pipelines benchmark which had virtually the identical risk ranking, which would result in the nuclear equity ratio at 50 per cent (Tr. Vol. 12, pp. 177-181). Instead, they first recommended 40 per cent for hydroelectric and only later 43 per cent (Tr. Vol. 12, p. 165; Ex. M10-T15-S19). This sort of uneven, unpredictable exercise of judgment should be rejected.

Nor is the intervenor criticism of Ms. McShane's analysis justified. The fundamental complaint they make is that Ms. McShane used methodologies that "are usually used to determine rate of return, not capital structure". (Pollution Probe argument, pp. 11; Tr. Vol. 11, pp. 82-83)

With respect, this fails to recognize that the cost of equity is a function of both business and financial risk (capital structure) and that the components of the cost of capital (e.g., capital structure and cost of equity) are inextricably linked (Tr. Vol. 11, p.12). The relationship between capital structure and ROE is well accepted (Tr. Vol. 12, p. 80). And, it is not possible to determine if the return on equity for a regulated business is fair and reasonable without reference to the capital structures of both the proxy companies and the specific regulated business to which the allowed return is intended to apply. Similarly, it is not possible to determine if the capital structure for a regulated business is fair and reasonable without reference to the cost of equity of the proxy companies. It is the overall return on capital which must meet the requirements of the fair return standard (Ex. C3-T1-S1, p. 16).

As Ms. McShane testified, capital structures maintained by utilities do not always fully compensate for differences in business risk (Ex. C3-T1-S1, p.18). This is the case in British Columbia for example. As Ms. McShane further explained, Drs. Kryzanowski and Roberts simply, "looked at the capital structures in isolation, and failed to look and see if there was any incremental risk compensation provided through additional return on equity." (Tr. Vol. 11, p. 12). The empirical methodologies she employed, however, allow for the segregation of risk compensation into business risk and financial risk components to assess how much of the difference in total risk is attributable to each. This information can then be used to determine what differences in capital structure between the regulated hydroelectric and nuclear operations are required in order to result in similar costs of equity for the two (Ex. L-10-023). None of Ms. McShane's studies, produced results that were sufficiently robust that she would be "comfortable recommending to the Board different capital structures for the prescribed nuclear and hydroelectric assets." (Tr. Vol. 11, p. 10).

As a result, OPG continues to support the use of a single cost of capital for its prescribed facilities for the reasons above and those set out in its evidence and AIC. If, however, the OEB were to order technology-specific capital structures, the only reasonable ratios would be 45 and 50 per cent for the hydroelectric and nuclear operations, respectively. This, at least, would be consistent with the evidence of Drs. Kryzanowski and Roberts in this case and the AUC proceeding. Under no circumstances should the relevant ratios be 40 and 50 per cent as advocated by Energy Probe. No expert supported these figures and, contrary to the OEB's direction in the last case, they would result in a significant revenue shortfall to OPG (Tr. Vol. 12, p. 164; Tr. Vol. 12, p. 143; Ex. M10-T15-S19).

8.7 COST OF DEBT

Board staff argues that in the event the OEB were to adopt technology-specific costs of capital it should consider extending this approach to OPG's cost of debt. With respect, staff's proposal is contrary to the only evidence directly on point.

At page 17 of its argument, Board staff asserts that it "disagrees with OPG's premise that the debt rates of the "Niagara X" debt instruments solely reflect OPG's corporate risk." Staff goes on to say that their "reading of OPG's evidence would suggest that the funding arrangement with the Ontario Electricity Financial Corporation ("OEFC") for the Niagara Tunnel reflects project-specific risk in addition to OPG's corporate risk" and that this "is what would generally be expected in the market".

Board staff did not ask any of OPG's witnesses in cross-examination about Board staff's "reading" of OPG's evidence, nor about staff's expectation of the market. As a result, while Board staff is correct that the particular needs of a project drive the amount and timing of debt issued by the OEFC (in the case above, pursuant to a credit facility arranged for the purpose of financing the Niagara Tunnel project), they are wrong in concluding that the cost of that debt is specific to that project. Rather, the cost of the debt is related to OPG's corporate borrowing costs and reflects the risk assessment of the entire corporation, of which the Niagara Tunnel is but a part. This is exactly what Mr. Lee indicated in response to questioning from Board staff counsel (Tr. Vol. 12, p. 109).

In addition, as noted in the Attachment 1 to interrogatory L-14-076 in EB-2007-0905, the rate for an advance under the OEFC agreement consists of the Base Rate plus the Applicable Spread (refer to Section 3.4). The Applicable Spread is defined in this agreement as "the additional interest in basis points over the Base Rate that will apply to an Advance, as determined by OEFC based on a survey of market rates". The survey performed by the OEFC considers OPG as a corporate entity only and is not related to any specific project.

Further, the fact that the debt rate reflects OPG's overall risk is also abundantly clear from a review of the evidence relating to the unhedged cost of borrowing associated with the Niagara Tunnel and corporate issues, which are at exactly the <u>same</u> rates. For example, as detailed in Ex C1-T1-S2 Table 6a, footnote 12, Corporate Issue 24 and Niagara Issue 15 are both forecast to be issued in Q1 2011 at a rate of 5.20 per cent, whereas, Corporate Issue 25 and Niagara issue 17 are both forecast to be issued in Q3 2011 at a rate of 5.45 per cent.

9.0 NUCLEAR WASTE AND DECOMISSIONING LIABILITIES

> **Issue 8.1** - Have any regulatory or other bodies issued position or policy papers, or made decisions, with respect to Asset Retirement Obligations that the Board should consider in determining whether to retain the existing methodology or adopt a new or modified methodology?

> **Issue 8.2** - Is the revenue requirement amount for nuclear liabilities related to nuclear waste management and decommissioning costs appropriately determined?

Only CME made submissions with respect to Issue 8.1 and these were only to confirm that it shares the view put forward by OPG that the National Energy Board activity with respect to asset retirement obligations was not sufficiently developed to be considered (CME argument, para.134; Ex. L-01-128). Therefore, OPG submits there are no developments with respect to asset retirement obligations that the OEB should consider in reviewing OPG's treatment of nuclear liabilities.

With respect to the revenue requirement impact of the nuclear liabilities (Issue 8.2), parties' submissions focused on two areas:

- The impact of end-of-life dates for Pickering and Darlington on the revenue requirement associated with recovery of nuclear liabilities; and
- The treatment of nuclear liability costs for 2010.

These issues are considered separately below.

As stated in its AIC, OPG adopted the methodology approved by the OEB in EB-2007-0905 to determine the revenue requirement impact of its nuclear liabilities. No party has identified any concerns regarding OPG's application of this methodology. As such, and subject to the OEB's determination on the two issues considered below, the revenue requirement amount for the nuclear liabilities should be approved as filed.

Impact of End-of-Life Dates for Pickering and Darlington

Energy Probe and GEC assert that the test period revenue requirement is too low. Energy Probe bases its argument on, what it says, are unrealistic end-of-life dates for the Pickering A and Darlington stations (EP argument, para. 113). GEC argues that the decision to move the Darlington dates is premature (GEC argument, p. 44). It also claims that the calculation of revenue requirement is not in accordance with O. Reg. 53/05.

OPG has responded to the criticism of the Pickering and Darlington end-of-life assumptions at Section 6.1, Depreciation. OPG maintains that the revenue requirement impact from nuclear liabilities associated with the prescribed and Bruce facilities as detailed in Ex. C2-T1-S2, pages 4 to 9 is appropriate, consistent with legislative requirements and should be approved.

GEC asserts that O. Reg. 53/05, section 6(2)(8) requires that the OEB "ensure that Ontario Power Generation Inc. recovers the revenue requirement impact of its nuclear decommissioning liability arising from the current approved reference plan" arguing that there is no new reference plan reflecting Darlington Refurbishment; therefore OPG is asking the OEB to act contrary to the law. OPG disagrees.

OPG's position in respect of the GAAP-driven change in the revenue requirement impact of nuclear liabilities is consistent with O. Reg. 53/05, section 6(2)(8). As discussed during the hearing, the calculation of the impacts of Darlington Refurbishment on nuclear liabilities is based on the costs in the currently approved 2006 reference plan and no new reference plan has been approved.[49] (Tr. Vol. 11, pp. 144-146)

Treatment of Nuclear Liability Costs for 2010

VECC agrees with OPG's submissions on the consistency of the calculation of the impacts of Darlington Refurbishment with O. Reg. 53/05 (VECC argument, paras. 60-82). It argues, however, that impacts also arose in 2010, and these, somehow, should be credited to ratepayers. CME adopts VECC's submissions on this issue (CME

49 Sometimes referred to in the record as the 2007 reference plan.

argument, para. 135). Essentially, VECC and CME assert that OPG avoided the operation of the Nuclear Liability Deferral Account in seeking a waiver of the ONFA requirement to file a new or revised reference plan and by not advising the OEB at an earlier date of its decision to proceed with the Darlington Refurbishment project.

VECC, supported by CME, accepts the revenue requirement impacts arising from the Darlington Refurbishment. It argues, however, that OPG should be made to account for out of period (2010) consequences of that project which should be used “as an offset to the test period revenue requirement” (VECC argument, para 61; CME argument, para. 135). The amount of this credit is said to be $64.2M, exclusive of related tax impacts of $26.2M which impacts, they argue, should be used to reduce the 2010 Tax Loss Variance Account amount of $195M.

With respect, the VECC and CME arguments misstate the evidence as to the timing of the decision to proceed with the Darlington Refurbishment project; ignore the evidence with respect to the effort necessary to prepare a new reference plan and the associated timing of such a plan; and ultimately advance a proposal which amounts to retroactive ratemaking.

As detailed in Ex. D2-T2-S1, Attachment 4, pages 16 to 17, OPG did not receive approval from its Board of Directors to proceed with the Darlington Refurbishment project until November of last year. Only then was the Economic Feasibility Assessment finalized and a recommendation made to OPG’s Board of Directors, which was accepted in a decision that was ultimately concurred with by the Province. VECC’s suggestion that the recommendation was made in December 2008 is plainly wrong. For the same reason, its suggestion that OPG should have disclosed the project when it applied for an accounting order in June 2009 is equally incorrect. At that time, no decision to proceed with the project had been made.

To suggest that OPG should have informed the OEB of the impacts of its decision to refurbish Darlington prior to 2010 ignores the timing realities. OPG filed its application with the OEB in May 2010, as soon as could reasonably be achieved following the completion of its business plan at the end of 2009 and given its decision in April to review the application to lessen the impacts on ratepayers. In its application, OPG provided the OEB and all intervenors with a detailed and complete presentation of the revenue requirement impacts of the decision to proceed with Darlington refurbishment.

In addition, to the extent that parties are implying that there was an obligation on OPG to inform the OEB, OPG does not agree it had any such obligation. Nuclear liabilities costs were only one element of a budget for 2010 where a large number of elements were significantly different from the values that underpinned the payment amounts in effect for 2010. As noted above, OPG's forecast for 2010 shows that it will under-earn compared to its OEB approved return (Ex. C1-T1-S1, p. 3 and Table 3). OPG is not aware of any requirement that it report on this under-earning and does not see much value in such an interim report given that, the costs and earnings from 2010 were going to be included in the rate application that was in preparation.

Shortly after receiving approval to proceed with the Darlington Refurbishment project, OPG wrote to the Province pursuant to s.5.1.2 of the ONFA and sought a waiver of the requirement that OPG prepare a new or amended Reference Plan "as soon as practically possible" (J.11.4). OPG received that waiver several months later in late May 2010.

Contrary to intervenor submissions, OPG's request was comprehensive, recognizing the significant effort necessary to prepare a new plan, and the limited utility of such an exercise having regard to the fact that OPG had already committed to submitting a comprehensive update in mid-2011. OPG wrote:

> While OPG is in the process of revising and updating all of its nuclear waste management and decommissions cost estimates in preparation for the 2012 ONFA Reference Plan update, it would likely take until early 2011 to finalize any updates to the current 2007 Reference Plan for the change to the Darlington Planning assumptions, and the resulting updates to contribution levels to the Used Fuel Fund and the Decommissioning Fund - all of which can be accommodated at the time of the 2012 ONFA Reference Plan update. (J11.4)

VECC and CME fail to recognize the process already in place to produce a new reference plan and the evidence that any new plan would not have been available until the next year in any event.

Ultimately, the VECC and CME proposals would result in retroactive ratemaking. As they concede, there is no variance account available to capture the alleged 2010 “overpayment” by ratepayers. Indeed, they suggest a credit against “new test period rates or against existing deferral account accounts”. CME explicitly urges the OEB to ignore the prohibition on retroactive ratemaking, saying “If there is no deferral account protection for the overpayment amount, then the Board should deduct it from the revenue requirement envelope it approves for the purposes of determining OPG's nuclear payment amount for the 2011 and 2012 test period.” (CME argument, para. 140). This is the very definition of retroactive rate making; adjusting current rates to recognize out of period events.

SEC indicates that they agree with VECC “in principle” that the 2010 impacts should be treated as a credit to ratepayers in either the Nuclear Liability Deferral Account or the Capacity Refurbishment Variance Account, although they do not support this course of action (SEC argument, para. 4.5.38 and 4.5.41). SEC’s suggestion that the 2010 impacts could be recorded in the Capacity Refurbishment Variance Account is inconsistent with the definition of that account. The Capacity Variance Account records those costs incurred to “increase the output of, refurbish or add operating capacity to” a prescribed facilities (EB-2007-0905 Payment Amounts Order, Appendix F, p. 5). OPG submits that this definition and encompasses the project costs but not the consequent impacts on ARC, depreciation, etc. The remainder of SEC’s arguments regarding the 2010 impact of the Darlington Refurbishment project are considered in Section 4.8 Darlington Refurbishment.

VECC’s alternative proposal to adjust OPG's Asset Retirement Costs downwards by $64.2M in 2010 is equally misplaced. Not only does this also result in retroactive rate making, the $64.2M is comprised of a series of revenue requirement impacts, including depreciation, used fuel storage and disposal variable expenses, and low and intermediate level waste variable expenses, which are unrelated to the ARC asset value adjustment (Ex. L-14-35 Attachment 1). As a result, the impact of the proposed adjustment to revenue requirement would not be equivalent to $64.2M. OPG submits that it would be inappropriate to adjust the ARC, which is a component of rate base, to effect revenue requirement impacts.

In any event, as OPG has argued elsewhere, its decision to not apply for 2010 rates was beneficial to ratepayers; overall OPG has under-earned in 2010. As highlighted in Ex L-14-035, the Darlington Refurbishment project is just one of many elements of costs and revenues for 2010 which do not have variance account treatment. When all such variances between costs and revenues for 2010 are accounted for, OPG's forecast ROE is 7.8 per cent (Ex C1-T1-S1, p. 3), which is less than OPG's approved ROE of 8.65 per cent.

With respect to the issue of related tax impacts, VECC is wrong that these would be part of the Tax Loss Variance Account. This account captures, among other things, the differences between the tax amounts that underpin the payment amount order in EB-2007-0905 and the amounts resulting from re-analysis of the prior period tax returns according to the OEB's directions in that proceeding (Decision and Order, EB-2009-0038). The account does not cover changes in 2010 actual amounts resulting from the Darlington Refurbishment project. The revenue requirement impact pertaining to income taxes should be treated the same as the revenue requirement impact associated with non-tax factors. They are simply not relevant to the determination of the test period revenue requirement.

Based on the above, OPG submits that its position is consistent with O. Reg. 53/05, and the operation of Nuclear Liabilities Variance Account. This latter account is designed to capture the revenue requirement impact resulting from a change in the approved reference plan, and no such change has occurred in 2010, nor is a change planned for 2011. The effective date for the next reference plan is January 1, 2012 and OPG will use the account to record the revenue requirement impact of the change in reference plan at that time.

If, in the alternative, the OEB determines that OPG's proposal is not consistent with section 6(2)8 of O. Reg. 53/05, OPG submits the only reasonable alternative treatment for nuclear liabilities is that advanced by GEC. That is, the revenue requirement should be adjusted upward to reflect the end-of-life dates that were used in the current ONFA reference plan.

10.0 RATE BASE

10.1 PRESCRIBED FACILITY RATE BASE

Issue 2.1 - What is the appropriate amount for rate base?

Regulated Hydroelectric Rate Base

No party objected to OPG's proposal for the regulated hydroelectric facilities rate base, with the exception of the inclusion of the St. Lawrence Power Development Visitor Centre (considered in Section 3.4, Hydroelectric Capital Projects). As such, and for the reasons set out in its evidence and AIC, OPG submits that the rate base for the regulated hydroelectric facilities should be accepted by the OEB as filed, subject to its findings on the Visitor Centre

Nuclear Rate Base

Board staff, supported by CME, SEC and VECC, propose reductions to nuclear rate base associated with historical and bridge year spending levels and two projects, the Weld Overlay project and the Maintenance Facility at Darlington project. AMPCO makes submissions on the Pickering Cafeteria project and the Darlington Change Room project. These submissions are considered in Section 4.6, Nuclear Projects. Subject to the OEB's findings on these issues, and for all of the reasons set out in its evidence and AIC, OPG submits that the nuclear rate base should be accepted as filed.

10.2 CWIP IN RATE BASE

Issue 2.2 - Is OPG's proposal to include CWIP in rate base for the Darlington Refurbishment Project appropriate?

Introduction

On April 3, 2009, the Chair of the OEB issued a statement indicating that the OEB was going to consider amendments to several existing regulatory constructs with the goal of removing barriers to infrastructure investment in Ontario. In his Statement dated April 3, the Chair indicated:

> The magnitude of current and future utility infrastructure investment has led me to consider how the OEB could create conditions which would foster timely investment by utilities in required infrastructure.

The process initiated by the Chair resulted in a January 15, 2010, Report of the Board on The Regulatory Treatment of Infrastructure Investment in connection with Rate-regulated Activities of Distributors and Transmitters in Ontario – EB-2009-0152 (the "Report").

The Report states that the OEB will consider, among other things, applications to include CWIP in rate base on a case-by-case basis, in advance of a project being declared in-service. As concluded in the Report, inclusion of CWIP in rate base is consistent with the Chair's stated objective above and is an important mechanism that is widely used in North America to reduce barriers to investment by utilities (see, Ex. D4-T1-S1, p. 1).

As discussed below, OPG submits that inclusion of CWIP in rate base for the Darlington Refurbishment project meets the criteria for qualifying investments specified by the OEB in its Report. Under OPG's proposal, 100 per cent of the forecast Darlington Refurbishment project capital would be placed into rate base and would receive the OEB-approved weighted average cost of capital. Any recovery of depreciation on this capital would be deferred until the assets come into service. The impact on the return on capital of any variance in planned capital expenditures would be captured in the Capacity Refurbishment Variance Account, as noted in Ex. H1-T3-S1, sec. 3.3.4.

As OPG testified, CWIP in rate base provides two principal benefits. First, it provides a smoothing effect on rates and thereby mitigates the rate shock that would otherwise occur when a large new plant is placed into service. Second, it can reduce borrowing costs. Both of these benefits apply in the case of the Darlington Refurbishment project (Tr. Vol. 14. P. 17).

Table 1 in Ex. D2-T2-S2 and Ex. L-14-004 illustrate the projected rate impacts of including Darlington Refurbishment CWIP in rate base. When considering these rate impacts, it is important to note that this analysis looks solely at the rate impact of the Darlington Refurbishment project. As with any other utility, OPG would expect to have other costs pressures during the project period that would also serve to increase rates (Tr. Vol. 13, p. 60).

As expected, the project rate impacts show that early recovery of refurbishment costs leads to smaller and more gradual rate increases compared to the rate shock associated with the traditional regulatory approach in 2020 when the first unit returns to service. Furthermore, there is a lasting benefit of lower rates post the in-service date.

Two intervenors, the PWU and the Society, supported OPG's proposal to include CWIP in rate base for the Darlington Refurbishment project (Ex. D2-T2-S2, p. 1). OPG's proposal results in an addition to rate base of $125.5M in 2011 and $306.0M in 2012 (Ex. B3-T1-S1 Table 1) and has a test period impact of $37.9M on the nuclear revenue requirement (Ex. D2-T2-S2 Table 1).

The PWU and the Society also accepted OPG's evidence that the proposal to include Darlington Refurbishment CWIP in rate base was consistent with the OEB's Report (EB-2009-0152), and will lessen the rate shock experienced by ratepayers when the refurbished reactors start to come into service in 2020 (PWU argument, para. 58, and Society argument, paras. 27 and 28).

A variety of objections to OPG's CWIP proposal were raised by intervenors. Some intervenors are opposed to the Darlington Refurbishment project in general and they therefore do not support any associated proposal (OPG's reply to those opposed to the project in general can be found in Section 4.8 Darlington Refurbishment). Some intervenors argue that the CWIP proposal should be denied because the OEB's Report does not, in their view, apply to OPG. Still others want to re-argue the CWIP issue from first principles and to try and convince the OEB that it should never be allowed. Lastly, there were those intervenors who argue that the issues of rate shock and impact on credit metrics and the other considerations set out by the OEB in its Report do not apply in the circumstances of the Darlington Refurbishment project.

Before replying to these arguments, OPG wants to address the evidence of Mr. Chernick, sponsored by GEC.

As noted by the PWU, Mr. Chernick's analysis was grounded in his interpretation of the OEB's Report and his application of a prior OEB decision (EB-2006-0501) on a Hydro One application for CWIP in rate base (PWU argument, para. 110). The Hydro One decision, of course, predates the Report in which the OEB adopts the CWIP in rate base approach as an alternative regulatory mechanism.

As also noted by the PWU, the concerns that Mr. Chernick identifies (e.g., used and useful, intergenerational equity) are merely complaints about the CWIP *concept* rather than OPG's specific proposal (PWU argument, para. 111). Also, under cross-examination by the PWU, Mr. Chernick agreed that the Board's Report could be read to mean that CWIP in rate base was not limited to transmission and distribution projects, but is "potentially in appropriate circumstances in relation to other types of investments" (Tr. Vol. 14, p. 38). And as part of his direct testimony, Mr. Chernick stated that his pre-existing view was that CWIP in rate base "was not a good idea" (Tr. Vol. 14, p. 21).

Given his concession as to the potential scope of the Report, his predisposition on the issue and the fact that much of his evidence is essentially attempting to re-argue the issues already decided in the EB-2009-0152 Report, OPG submits that Mr. Chernick's evidence should be given little or no weight.

The OEB's Report (EB-2009-0152) Should Apply to OPG

Several intervenors, including Board staff, VECC and Pollution Probe, argue that the OEB's Report does not apply to OPG and to the Darlington Refurbishment project (Board staff argument, p. 36; PP argument, pp. 2-3; VECC argument, para. 8). In their submissions, they cite parts of the Report to support their arguments. OPG, in its evidence and testimony, cites other parts of the Report and the statements from the Chair in support of its view that the Report permits OPG to make its case to the Board that CWIP in rate base should be allowed for the Darlington Refurbishment project (Ex. L-01-011).

As OPG testified, the OEB knows what it meant when it wrote the Report (Tr. Vol. 14, p. 13). OPG expects that the OEB's decision in this case will make it clear whether the Report applies to OPG and whether the options set out in that Report are available to OPG. As a consequence, OPG does not believe that it is useful to respond to the numerous specific submissions made by intervenors and Board staff regarding the applicability of the Report.

However, in OPG's view, it cannot be disputed that the concerns that caused the OEB to launch the process that led to the Report – the need to support large infrastructure investment in the electricity sector – apply in the case of the Darlington Refurbishment project. Equally, it cannot be reasonably disputed that the rate shock and utility credit metric concerns that led the OEB to make CWIP in rate base available also apply in the case of the Darlington Refurbishment project. As OPG's witness summarized, given the significant cost and duration of this undertaking, the Darlington Refurbishment project is the "poster child" for CWIP in rate base (Tr. Vol. 13, p. 146).

Accordingly, regardless of what the OEB ultimately determines about the scope of the Report, OPG submits that there is nothing that prevents the OEB from approving CWIP in rate base for the Darlington Refurbishment project if the OEB believes it is appropriate to do so. Applying the same logic and analysis that the OEB used to find in favour of CWIP in rate base as a concept can lead to only one reasonable conclusion in OPG's submission, namely that CWIP in rate base should be allowed for the Darlington Refurbishment project (Tr. Vol. 14, p. 13, Tr. Vol. 13, p. 144):

The OEB Should Reject Attempts to Re-argue EB-2009-0152

A number of intervenors appear to be re-arguing matters already determined EB-2009-0152. The OEB should not be drawn into a re-hearing on the CWIP in rate base option by those who disagree with the conclusions in the OEB's Report.

CCC, SEC and GEC raise the issue of inter-generational inequity (CCC argument, para. 110; SEC argument, para. 2.2.11; GEC argument, p. 32).

As pointed out by OPG, rate regulation often results in inter-generational transfers. Good regulation has the objective of making sure such transfers are not undue – not that they don't happen at all. OPG's CWIP proposal is of benefit to future ratepayers at a cost to current ratepayers, but there is no undue transfer. And as noted at the outset, this is a concern that the OEB already considered when it issued its Report.

GEC argues that "elderly customers and struggling businesses" (GEC argument, p. 32) should not be asked to finance OPG plans. Interestingly, GEC does not appear to have similar concerns regarding the financing of "green energy projects" that it believes are within the criteria of the EB-2009-0152 Report.

Others have raised the concern that the application of CWIP in rate base treatment is not consistent with the "used and useful" principle. However, this is not a feature unique to OPG or the Darlington Refurbishment project. Rather, it is an intrinsic feature of the CWIP in rate base mechanism. It is clear that when the OEB developed the EB-2009-0152 Report it was prepared to approve exceptions to the traditional "used and useful" approach (Tr. Vol. 14, p. 42).

It was also suggested by GEC that the application of CWIP in rate base treatment is inappropriate in this case because OPG's customers have a higher cost of capital than OPG does. OPG notes that no evidence was filed with respect to the cost of capital of OPG's customers. Likely some consumers will have a higher cost of capital than OPG, while for others it is likely lower.[50]

This argument relates to a generic issue associated with the use of the CWIP in rate base. There is nothing unique about OPG, or its customers or their respective costs of capital, that would not be the case with many, if not most, other utilities.

All of the above referenced submissions are really arguments that the OEB should never have adopted CWIP mechanism in its Report, rather than arguments that this mechanism should not be applied to the Darlington Refurbishment project.

The OEB Has Found that CWIP Can Help Address Rate Shock

Board staff notes that CWIP in rate base can be an effective tool in addressing rate shock (Board staff argument, p. 38). However, they are not concerned about this issue in the case of the Darlington Refurbishment project because, with reference to Ex. J14.2, the rate shock is only evident in one year, from 2019 to 2020.

To OPG this seems a very odd submission. Most utility projects, and certainly most of the projects that would be covered by EB-2009-0152, come into service at a single point

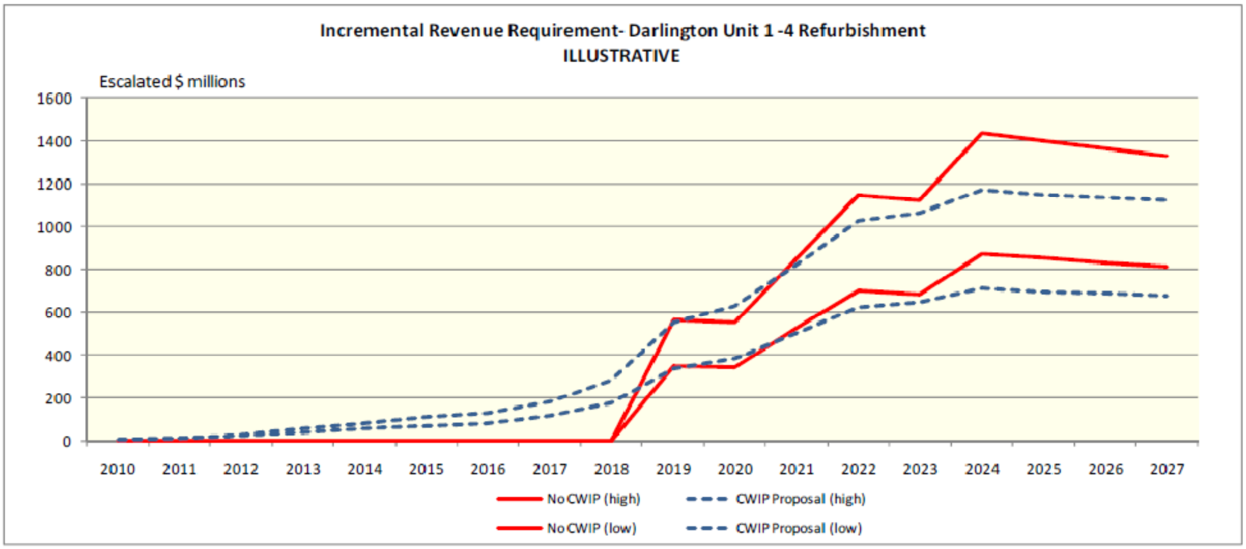
[50] EB-2010-0008, Transcript Volume 13, Page 67, Lines 21-27.

in time and therefore only provide a rate shock in one year. Yet the OEB Report concludes that CWIP in rate base should be available to these projects.

This submission also completely ignores that size of the projected rate shock in 2020. As can be seen from J14.2, the estimated increase in 2020, for this one item in the revenue requirement, ranges from $357M to $561M in 2009$. Yet Board staff is not concerned about this size of increase. By contrast, Board staff currently seems very concerned about the customer impacts attributable to the clearance of the Bruce Lease Net Revenues Variance Account forecast balance of $296.6M over 22 months (Board staff argument, p. 93). OPG submits that a future OEB staff will very likely have a very different view of things if the CWIP in rate base proposal for Darlington Refurbishment project is not approved.

SEC and others argue that the need for rate shock mitigation has not been proven. If a project estimated to cost between $6 and $10 billion (2009$) is not large enough to cause rate shock as it is phased in, one has to wonder what size project would be required. With respect to the "rate smoothing" issue, OPG provided a graph of the projected cash flows associated with the Darlington Refurbishment project reflecting the effect of the conventional regulatory treatment as well as a CWIP in rate base approach:

All 4 Darlington Units



In OPG's submission, this graph shows quite effectively how the CWIP in rate base will lessen the rate shock forecast for 2019-2020.

OPG Has Established the Potential Impacts on its Credit Metrics

Board staff and VECC argue that there is little evidence on the impact on credit risk to OPG (Board staff argument, p. 37; VECC argument, para. 8). Board staff goes on to say that OPG does not appear to be concerned with its borrowing costs (Board staff argument, pp. 37-38). As OPG will show below, both of these submissions are inconsistent with the evidence in the hearing.

At Ex. A2-T3-S1, OPG provides two rating agency reports (Standard & Poor's and DBRS) that assess OPG's long-term credit rating as being in the low "A" range. Both agencies refer to OPG's nuclear program and Standard & Poor's specifically references OPG's weak cash flow metrics. Similarly, Fitch Ratings noted in a discussion of nuclear plant construction financing in the U.S. that: "For regulated U.S. utilities, the availability of a cash return on construction work in progress (CWIP) would reduce the construction risk."(Ex. D2-T2-S2, p. 9).[51]

[51] Fitch Ratings, U.S. Nuclear Power: Credit Implications, November 2, 2006. Emphasis added.

OPG also referred to a report by DBRS, which commented that:

> Interest expense is expected to increase in the medium term, given the debt financing required to fund the increased capital expenditures; therefore, coverage ratios will weaken slightly. Furthermore, should the nuclear refurbishments and nuclear new-build generating projects be approved, the Company will witness a substantial increase in interest expense as the projects are significant in size.
>
> As debt is added to fund capital expenditures, credit metrics would be expected to decline from current levels as assets do not generate earnings or cash flows until placed in service. Once in service, metrics would be expected to improve.[52]

In OPG's submission it is not surprising that OPG can't quantify the impact on its credit metrics from the Darlington Refurbishment project at this early stage of the project. The final impact can likely only be quantified after the OEB's decision in this hearing, the finalization of financing for the project and after the rating agencies have had a chance to assess all of these things.

While it is not possible to provide quantification of the impact at this point, it is expected that there will be a negative impact on OPG's credit metrics if the CWIP in rate base proposal is not approved (Tr. Vol. 14. P. 17).

As OPG's witness testified, refurbishment is an incremental risk that is not reflected in OPG's current cost of capital or in the current credit rating (Tr. Vol. 13, pp. 156-157). The CWIP proposal, if approved will result in better financial metrics than if the proposal is not approved. The inclusion of CWIP in rate base will reduce OPG's borrowing costs, to the benefit of ratepayers, over the life of the project.

OPG Has Met the Factors for CWIP Outlined by the OEB

In Section 3.4 of its Report, the OEB set out a number of factors that it will evaluate when considering a proposal for alternative regulatory mechanisms. In OPG's submission an analysis of the Darlington Refurbishment project against these factors provides compelling case for the application of CWIP in rate base.

[52] EB-2010-0008, Exhibit A2, Tab 3, Schedule 1, Attachment 1, pp. 7-8.

Need and Public Interest

With respect to the need for and the public interest benefits of the project, OPG submits that there is very strong evidence to show that these factors have been satisfied. As OPG testified, the OEB should give significant weight to the fact that the Government of Ontario has concurred with OPG's decision to proceed with this project (Ex. D2-T2-S1, Attachment 3, Tr. Vol. 13, p. 149). This endorsement was later reinforced in the Government's Long Term Energy Plan issued on November 23, 2010 and in the draft Supply Mix Directive posted on the Environmental Registry system (EBR Registry Number: 011-1701) on November 23, 2010. Similarly the draft Supply Mix Directive, which once finalized and issued, will be binding on the OPA as they complete their new Integrated Power System Plan ("IPSP"), provides for the following:

> The OPA shall continue to plan for nuclear generation to account for approximately 50 per cent of total Ontario electricity generation. To this end, the Plan shall provide for the refurbishment of 10,000 MW of existing nuclear capacity at the Bruce Nuclear Generating Station and the Darlington Nuclear Generating Station as well as the procurement of two new nuclear generating units (about 2,000 MW) at the Darlington site. The Government will pursue this procurement where it can be achieved in a cost-effective manner.

Given that the Government has expressly indicated its support for the Darlington Refurbishment project, the OEB should conclude that the project is both needed and in the public interest. Pollution Probe argues that CWIP proposal should not be approved before the project has been found to be "in public interest". As OPG has pointed out, there is no provision in the *OEB Act* or in the regulations governing OPG, for the OEB to grant approval of the project (Tr. Vol. 13, pp. 80-81). OPG interprets the Minister's support and approval of project as a determination by the Government that the project is in the public interest. In OPG's submission, as noted above, this determination by the Government should be sufficient for the Board to conclude that the project is both needed and in the public interest.

The Cost and Scope of the Darlington Refurbishment Project Reinforces the Need for CWIP

Two of the criteria in the Report relate to a project's cost, and the risks and challenges that it faces. A third relates to the cost relative to the size of the proponent's rate base.

All of these criteria are met here. The overall cost of the Darlington Refurbishment project is estimated to be in the range of $6B to $10B, expressed in 2009 dollars on an overnight basis. The project will take about 18 years from start to finish (Ex. D2-T2-S1, Attachment 2, p. 20). This project is without question the largest project being undertaken by a regulated utility in Ontario. On the basis of the significant overall cost, OPG submits that the project deserves access to the alternative treatment set out in the Report.

The key risks or particular challenges associated with completion of the project are set out in Ex. D2-T2-S1, Attachment 1, page 9 and the risk management process is set out in the Project Execution Plan (Ex. D2-T2-S1, Attachment 2, p. 27). The risks and challenges associated with the project were discussed further by OPG's witnesses (Tr. Vol. 13, pp. 115-116, Tr. Vol. 13, p. 75-76). These risks and challenges are broadly similar to the risks and challenges faced by Green Energy Act projects, including the potential for project delays, public controversy, and the recovery of costs (Ex. D2-T2-S2, p. 3). Accordingly, OPG submits that the Darlington Refurbishment project satisfies this criterion.

The costs of the project in proportion to the current rate base for OPG are significant. As explained at Ex. D2-T2-S2, pages 4-5, the project's capital cost range of $6B-$10B is greater than OPG's nuclear rate base for 2012 of approximately $4B. The upper bound of the estimate is even greater than OPG's combined nuclear and hydroelectric rate base of $7.8B. Given the size of the Darlington Refurbishment project, OPG submits that it has more than satisfied this factor.

Current Regulatory Mechanisms Are Inadequate for Darlington Refurbishment

OPG has testified that it does not believe that it is appropriate to rely on the current regulatory mechanisms for this project. The reasons for this view are usefully summarized in an exchange between Ms. Chaplin, the Panel Chair, and Mr. Barrett speaking for OPG:

> MS. CHAPLIN: And sort of at the end of the day, would you say the two primary reasons that are being advanced are the smoothing effect and OPG's concerns around cash flow and recovering the cost of the funds used to support it?

> Are they equally important in your mind? Is one more important than the other?
>
> MR. BARRETT: I guess there are really three reasons in our mind, and there may be some subtleties between them. The first one is the rate shock issue. That is our primary concern.
>
> We have experience with how difficult it can be to bring forward significant rate increases, and we wanted to avoid that. And we accept that that is difficult for customers.
>
> We have a concern about the impact on our credit metrics. We acknowledge that we haven't been able to quantify that at this point, but we expect there to be a negative impact.
>
> Then the third issue relates to the subsidy that we have discussed, the difference between the IDC rate and the AFUDC rate. (Tr. Vol. 14, p. 17)

In OPG's submission, it can be seen from this exchange that OPG has very sound reasons for seeking a change from the current regulatory mechanisms and the adoption of CWIP in rate base for this project.

Darlington is a Significant Portion of Ontario's Future Energy Supply

The final factor from the OEB's Report is whether the utility is otherwise obligated to undertake the project. As OPG has testified, it is not currently obligated to undertake the Darlington Refurbishment project. It did receive a directive from its Shareholder to study the refurbishment of the Darlington stations (Ex. D2-T2-S1, Attachment 5), however it has not received a directive to complete the project. OPG submits that given the importance the Government of Ontario has attached to maintaining nuclear at 50 per cent of baseload supply and the inclusion of this project in the Long Term Energy Plan and draft Supply Mix Directive, the OEB should have confidence the OPG will pursue the project (Tr. Vol. 13, p. 81). It is clear that in order to meet the needs of the Province of Ontario with respect to a diverse supply mix, requiring a combination of assets to ensure a balanced supply mix that is reliable, modern and cost-effective, OPG will necessarily be required to proceed with the Darlington Refurbishment project.

It was suggested that CWIP in rate base treatment in this case is not required because OPG has acknowledged that the project will proceed even if CWIP in rate base treatment is denied.[53] The OEB expressly addresses this issue in the EB-2009-0152 Report itself. It concludes that it will not be necessary for a utility to establish that "but for" CWIP treatment, the project will not proceed:

> The OEB will not impose a "but for" requirement in assessing the requisite relationship between the alternative mechanisms requested and the risks and challenges associated with the project. In other words, it will not be necessary for the applicant to demonstrate that the project will not, or is likely not, to proceed unless an alternative mechanism is granted in support of the project.[54]

CWIP Should Be Calculated Using the Weighted Average Cost of Capital

As noted earlier, Board staff does not support the inclusion of CWIP in rate base for the Darlington Refurbishment project. However, in the event that the OEB finds that CWIP should be included in rate base, Board staff suggests that OPG's return should be limited to only interest costs (Board staff argument., p. 38). This submission is also supported by VECC (VECC argument, para. 7) and AMPCO (AMPCO argument, p. 18).

Board staff offers little in the way of support for this submission. They appear to justify it on the basis of the OEB's 2007 decision on the Niagara Reinforcement Project ("NRP") (EB-2006-0501), ignoring the more recent determinations by the OEB in EB-2009-0152. In the NRP case, Hydro One had filed evidence indicating that work on the line had been suspended due to a land claims dispute. It was expected that construction would resume after a few years. The NRP CWIP balance was $97 million. The relatively small balance and the expected short duration in the NRP case are very different from the OPG's Darlington Refurbishment CWIP proposal. Board staff's proposal would imply that Darlington Refurbishment project could be financed by debt only, yet they cite no evidence to support this position. In OPG's submission, it is not credible to assume that a project of this size and duration can be financed entirely by debt.

Board staff's submission also ignores OPG's evidence that it will be financing a multi-billion budget, over many years, for the Darlington Refurbishment project – an amount larger than the rate bases of many of the regulated utilities in the province (Tr. Vol. 14, p.

[53] EB-2010-0008, Green Energy Coalition, Evidence Prepared by Paul Chernick, August 31, 2010, Page 12, Lines 1-10.
[54] EB-2009-0152 Report of the OEB, Page 20.

16). Yet Board staff has not opposed these other utilities earning a WACC on their rate bases.

This suggestion also ignores the large subsidy from OPG that this proposal would entail. Under the traditional regulatory treatment, OPG would be carrying a very large balance in its Darlington Refurbishment CWIP account for many years before the units came into service. If this very large balance does not earn OPG's weighted average cost of capital, then OPG's shareholder would, in effect, be subsidizing the Darlington Refurbishment Project (Tr. Vol. 14, pp. 16-17).

As indicated by OPG's witness the differences in the Net Present Values ("NPVs") between the CWIP Cases and the Current Methodology Cases shown in Ex. L-14-004 provide an estimate of the size of subsidy that OPG would be providing ratepayers. At a project cost of $6B (2000$, overnight) the subsidy is approximately $200M on a net present value basis. At a project cost of $10B (2009$, overnight) the subsidy is approximately $300M on a net present value basis.

And the evidence of Mr. Luciani is that most other jurisdictions, even those that do not provide for CWIP in rate base, allow for an AFUDC that includes both debt and equity (Tr. Vol. 13, pp. 153-154).

The OEB Should Approve OPG's CWIP Proposal

OPG submits that its proposal to include CWIP in rate base is reasonable and should be approved. The proposal is consistent with the OEB's Report (EB-2009-0152). It will also lessen the rate shock experienced by ratepayers when the refurbished reactors start to come into service in about 2020 period and reduce the negative impact on OPG's credit metrics during the construction period.

11.0 DEFERRAL AND VARIANCE ACCOUNTS

Issue 10.1 – Is the nature or type of costs recorded in the deferral and variance accounts appropriate?

Issue 10.2 – Are the balances for recovery in each of the deferral and variance accounts appropriate?

Issue 10.3 – Is the disposition methodology appropriate?

> **Issue 10.4** – Is the proposed continuation of deferral and variance accounts appropriate?
>
> **Issue 10.5** – Should the proposed variance account related to IESO non-energy charges be established?
>
> **Issue 10.6** – What other deferral and variance account, if any, should be established for the test period?

The submissions of Board staff and intervenors addressed only the following accounts:

- Tax Loss Variance Account;
- Bruce Lease Net Revenues Variance Account;
- Capacity Refurbishment Variance Account;
- Nuclear Liability Deferral Account;
- Nuclear Fuel Cost Variance Account;
- the proposed IESO Non-Energy Charges Variance Account; and
- the proposed Pension and Other Post Employment Benefits Cost Variance Account.

In addition, no submissions on OPG's proposed account disposition methodology were filed other than Board staff's request that OPG provide the audited 2010 deferral/variance account balances at the earliest possible time to allow for their inclusion in the OEB's decision. OPG agrees to do this and confirms that it will file audited variance and deferral account balances at that time, not audited financial statements (Tr. Vol. 15, p. 75).

Given that there no submissions in respect of OPG's other variance and deferral accounts and no substantive submissions with respect to the proposed disposition methodology, OPG submits that these proposals should be accepted by the OEB for the reasons set out in OPG's evidence and AIC (pp. 78-97).

11.1 TAX LOSS VARIANCE ACCOUNT

In EB-2009-0038, the OEB ordered the establishment of the Tax Loss Variance Account (the "TLVA"). The TLVA records the variance between: (a) "the tax loss mitigation amount which underpins the rate order for the test period" (which is the payment amounts order currently in force), and (b) "the tax loss amount resulting from the re-analysis of the prior period tax returns based on the Board's directions in the Payments Decision as to the recalculation of those tax losses" (EB-2009-0038, Decision and Order, p. 15).

In its evidence, OPG established that the balance in this account was calculated based upon accepted regulatory and accounting principles and substantiated the underlying tax values through a detailed analysis of its past tax returns. OPG submits that the TLVA balance sought by OPG is correct and fully accords with the OEB's rulings in EB-2007-0905 and EB-2009-0038 as well as regulatory, tax and accounting principles. Therefore, the balance should be recovered as proposed by OPG.

SEC was the only party to consider the issue of the TLVA in detail. In proposing an alternative method of calculating the TLVA balance, SEC offers a proposal that incorrectly applies regulatory and accounting principles; is fundamentally flawed in its approach; and contains numerous incorrect assumptions, calculation errors and other inaccuracies. As a result, the submissions of SEC should be rejected by the OEB.

Before considering SEC's submissions (which are addressed below in Sections 11.1.2 through 11.1.9), OPG addresses CCC's proposal that the OEB defer consideration of the issue to a separate proceeding. OPG addresses CME's submission on the TLVA with respect to "mitigation" in EB-2007-0905, as well as VECC's submission on the basis for continuing the TLVA during 2010 in Sections 11.1.10 and 11.1.11, respectively.

11.1.1 Decision Should Not Be Deferred

CCC asserts that the OEB defer consideration of the issue to a separate proceeding (CCC argument, para. 147). OPG submits that there is absolutely no reason for this issue to be deferred and that any deferral would present an unfair level of regulatory uncertainty and risk for OPG.

All parties were well aware from the time of the Decision in EB-2007-0905, which was issued on November 3, 2008, that the issue of tax losses from the prior period was to be considered in this hearing. The Decision clearly states:

> In its next application for payment amounts for the prescribed assets, the Board will require OPG to file better information on its forecast of the test period income tax provision. To that end, the income tax provision for the prescribed facilities should not include any income or loss in respect of the Bruce lease. The Board also expects OPG to file an analysis of its prior period tax returns that identifies all items (income inclusions, deductions, losses) in those returns that should be taken into account in the tax provision for the prescribed facilities. (emphasis added). (Decision with Reasons, EB-2007-0905, page 171)

The May 2009 Decision on the motion that established the TVLA reinforced this timing:

> The clearance of this account will be reviewed in OPG's next payment application hearing when a future panel of the Board reviews the tax analysis ordered in the Payments Decision. The Board anticipates that any issues related to tax calculations will be dealt with at the next payment amounts hearing. (emphasis added). (Decision and Order on Motion to Review and Vary, EB-2009-0038, page 15)

Had Board Staff or intervenors considered it appropriate to retain an expert on the issue, as suggested by CCC, they had sufficient notice to make such arrangements. Their failure to do so does not justify delaying resolution of this issue.

OPG has filed all of the information necessary for a decision to be reached. In addition to meeting the OEB's direction in EB-2007-0905 to file "better information on its forecast of the test period income tax provision" and "an analysis of prior period tax returns," OPG's application provided all of the tax information listed in the filing guidelines established for this proceeding in EB-2009-0331 (Filing Guidelines for Ontario Power Generation Inc., EB-2009-0331, p. 18).

In its pre-filed evidence, OPG supported the tax loss calculation for 2005-2007 in three ways (Ex. F4-T2-S1, p. 11):

- The regulatory taxes are calculated starting from regulatory earnings before tax and applying the methodology and additions and deductions used in the bridge and test period (Ex. F4-T2-S1, Table 7).

- The tax losses for 2005-2007 are reconciled with the tax loss calculations that were presented in OPG's evidence in EB-2007-0905 (Ex. F4-T2-S1, Table 8).

- The regulatory tax calculation is reconciled with OPG's corporate income tax returns, which were also filed (Ex. F4-T2-S1, Tables 10-12 and Attachment 3).

To assist the OEB and intervenors in verifying the accuracy of OPG's regulatory tax calculation, OPG engaged Ernst & Young to report on the reconciliation of information in the corporate income tax returns to the determination of prior period tax losses for the prescribed facilities for 2005, 2006 and 2007 (Ex. F4-T2-S1 Attachment 1). Ernst & Young's review found no exceptions to OPG's tax reconciliation (*Ibid.).*

OPG responded fully to numerous interrogatories, Technical Conference questions and undertakings regarding income tax matters. No intervenor has suggested that the information provided was insufficient, nor was there any limitation on their ability to request additional information through the discovery process or to test the information in the hearing.

The balance in the TLVA account is significant and it relates to tax calculations dating back to 2005. It is important to OPG that the matter is determined so that it does not continue to carry this significant regulatory asset without beginning to clear the balance. This balance relates to under-recovery from 2008-2010. From ratepayers' perspective, it would be inappropriate to push the clearance of this account to a future period, while it continues to accumulate interest and when other regulatory matters may emerge to place additional pressure on future payment amounts.

In addition to the foregoing, and of equal importance, SEC's submissions with respect to the TLVA are without merit, as shown below. So there is no reason to defer the clearance of this account to address SEC's issues. OPG submits that a decision regarding the approved balance in the Tax Loss Variance Account should not be deferred, but should be made in this proceeding.

11.1.2 Applicable Regulatory and Accounting Principles

As noted in the introduction, the variance to be calculated is the difference between the tax loss mitigation amount set out in the current payment amounts order and the tax loss amount resulting from the re-analysis of prior period tax returns based on the OEB's directions in EB-2007-0905. The first component of the variance is the amount of mitigation that was included in the payment amounts arising from the order in EB-2007-0905, $341.2M (Ex. H1-T1-S1, p. 7).[55] No party challenged this amount and it is not in dispute.

The second component of the variance is "the tax loss amount resulting from the re-analysis of the prior period tax returns" based on the OEB's ruling in EB-2007-0905. This is the aspect of the variance that is at issue. This amount is a tax loss of $110.9M, which corresponds to a revenue requirement impact of $50.3M (Ex. H1-T1-S1, p. 7). No party challenged the method OPG used to convert the tax loss amount into revenue requirement. As a result, the recorded difference in the account for the period April 1, 2008 - December 31, 2009 is $290.9M ($341.2M less $50.3M). Since the 2008-2009 payment amounts and the tax loss variance account continue in 2010, OPG is forecasting to record an additional amount of $195.0M in 2010, for a total balance of $485.8M, excluding interest (Ex. H1-T1-S1, Table 4, line 7). As noted above, submissions related to amounts recorded for 2010 are made in section 11.1.12. The submissions that follow relate to the calculation of the tax loss amount as of April 1, 2008 that forms the basis of the variance account entries in the TLVA.

The calculation above is consistent with the OEB's decision in EB-2007-0905 and EB-2009-0038. To be consistent with the OEB's rulings in EB-2007-0905 and EB-2009-0038, there are three aspects that must form the basis of the calculation. These are:

i. the calculation is in respect of <u>regulatory tax losses</u> only (Decision and Order, EB-2009-0038, p.16);
ii. the principle that the benefits must follow the costs and the stand-alone principle must apply (Ibid., p.15, nt. 18);
iii. any carry forward tax loss benefit for Bruce Nuclear revenues and costs must be excluded (Ibid., p.12).

(i) Consideration of Regulatory Tax Loss Only

[55] The $341.2M amount consists of the revenue requirement reduction of 22% of the deficiency of $168.7M and foregone tax expense and the related tax impact. SEC's argument concludes that the balance of the TLVA should only be $168.7M (SEC argument, para. 10.2.99) but it does not dispute that the remainder of the $341.2M was a component of the revenue requirement reduction ordered by the OEB in EB-2007-0905. SEC's position that only the $168.7M remains in the Tax Loss Variance Account is based on their submission that there are sufficient prior period net deductions to offset the foregone taxes and the related tax impact components of the TLVA.

The OEB in EB-2009-0038 considered a motion by OPG to review and vary the OEB's decision in EB-2007-0905 where the OEB decided to eliminate a tax provision in the test period, which it construed as "simply mitigation", and to require additional mitigation in the amount of 22 per cent of the revenue deficiency.

In EB-2009-0038, the OEB indicated that it must decide if the panel in EB-2007-0905 erred in (a) finding that OPG's proposal to eliminate an income tax provision in the test period was "simply mitigation", and unrelated to the regulatory <u>tax losses</u>; and (b) finding that there was no connection between the tax loss benefits and the revenue requirement reduction that OPG proposed in its application (Decision and Order, EB-2009-0038, p. 10). The OEB indicated that if it decides "that the findings and reductions are in error, then the Board must determine if the treatment of <u>tax losses</u> necessitates the establishment of a variance account" (emphasis added) (Ibid. p. 11).

The OEB found that there was an evidentiary link established between the regulatory tax losses and the revenue requirement reduction, and as a result, the OEB determined that there was an identifiable error that was material and relevant to the outcome of the reviewed decision (Decision and Order, EB-2009-0038, p. 15). As noted, the OEB varied the decision in EB-2007-0905 in a manner that links revenue requirement reduction and regulatory tax losses. As a result, it ordered the establishment of the tax loss variance account to record the variance between the tax loss mitigation amount in the rate order and the tax loss amount resulting from the re-analysis of prior period tax returns.

Based upon the forgoing, it is clear that in the OEB's decision in EB-2009-0038, the sole focus was on the tax losses for the period in question, which was the period from April 1, 2005 through to March 31, 2008. This is entirely consistent with the intention of the Decision in EB-2007-0905 to only assess the tax returns in this period to confirm the appropriate amount of tax losses (Decision with Reasons, EB-2007-0905, pp. 170-171).

(ii) Benefits Follow the Cost

The OEB in EB-2009-0038 made note of several determinations that the OEB rendered in EB-2007-0905, which impacted the calculation of taxes. In EB-2009-0038 the OEB noted (p. 12):

> In its decision, the Board also made other findings questioning OPG's regulatory tax calculations. It observed that it did not have the information necessary to determine the tax benefits which should be carried forward to offset payment amounts in 2008 and later periods, and ordered OPG to file better information and analysis on its forecast test period income tax provision in its next payment application. The Board stated that analysis should be based on the principle that if electricity consumers should bear a cost (or should benefit from revenues) they should receive the related tax benefit (or will be charged the related income taxes).

In particular, the OEB's Decision in EB-2007-0905 stated the following (p. 170):

> Although the Board is not convinced that regulatory tax loss carried forward existed at the end of 2007, or that OPG's treatment of taxes is appropriate, the Board is not making a finding that all the tax benefits of pre-2008 tax losses should accrue to OPG's shareholder. The Board believes that the benefit of tax deductions and losses that arose before the date of the Board's first order should be apportioned between electricity consumers and OPG based on the principle that the party who bears a cost should be entitled to any related tax savings or benefits. The Board has adopted this principle in other cases where a company owns both regulated and unregulated businesses. (emphasis added).

This statement is a restatement of the "benefits follow cost" principle affirmed by the OEB on a number of occasions in relation to tax and the stand-alone principle.

The test is whether the expenses that generate a deduction are used to determine rates. Put more simply, the test is whether the expenses are included in the relevant cost of service. If they are, the associated deductions and their tax reducing benefits will be taken into account in calculating taxable income or loss for the regulated entity. If the expenses are not included in rates, the deductions will not be taken into account. In this way, the taxable income or loss and the corresponding tax allowance for ratemaking purposes will reflect the ratepayers' contribution to taxable income.

SEC makes the bold, but incorrect claim, that if the OEB accepts the "benefits follow cost" principle, it must accept SEC's proposed disposition of the TLVA balances (SEC argument, para. 10.2.10). The error in SEC's submission is assuming that statement of this principle is the same as its application. In OPG's submission, as discussed fully below, SEC has incorrectly applied "benefits follow cost" to reach an erroneous conclusion and the OEB is free to accept the principle while rejecting SEC's analysis and result.

In determining the tax loss necessary to establish the balance of the TLVA, OPG has appropriately applied the stand-alone principle and the principle that the "benefits follow cost" in analyzing its prior period tax returns as directed by the OEB.

(iii) Bruce Lease Revenues and Costs Excluded

Further to the OEB's comments with respect to the stand-alone principle, the OEB in EB-2009-0038 specifically commented on the exclusion of Bruce Nuclear revenues and costs. In that decision the OEB stated (p. 12):

> In its application OPG treated Bruce Nuclear revenues and costs as though they were related to a regulated business. The Board did not agree with this treatment. The Board required OPG to make these calculations on the basis of Generally Accepted Accounting Principles ("GAAP") and not regulatory accounting. The Board indicated that the treatment of taxes on Bruce revenues and costs should be treated in a normal GAAP manner and a tax provision should be included in the calculation of the Bruce costs, contrary to OPG's proposal to carry forward loss benefits for Bruce revenues and costs.

These comment reiterated the OEB's findings in EB-2007-0905, in particular (p. 169):

> Reasons for the Board's concerns about OPG's treatment of taxes include:… OPG's calculation of regulatory tax losses for 2005 - 2007 include revenues and expenses related to OPG's Bruce lease. The Bruce stations are not prescribed facilities and OPG's Bruce lease is not regulated by the Board. In the Board's view, any calculation of tax losses in respect of the prescribed facilities should exclude revenues and expenses related to the Bruce lease.

OPG has appropriately excluded Bruce lease revenues and costs from its tax loss determination (see also, J14.5 and Tr. Vol. 14, pp. 159-165).

11.1.3 OEB Rulings Satisfied

Based on the forgoing and the discussion below, OPG submits that it has correctly completed its analysis of prior period tax returns to determine regulated tax losses based on the three aspects above.

Tables 10, 11 and 12 of Ex. F4-T2-S1 set out the detailed calculation of the stand-alone tax loss for OPG's regulated business for the years 2005 – 2007 starting with OPG's consolidated taxable income/(loss) per the tax returns filed and ending with the calculation of the regulatory taxable income/(loss) for the prescribed facilities.[56] Each column in these tables represents steps taken by OPG to arrive at a regulatory taxable income/loss for the applicable year incorporating the above benefits follow cost principle. Any revenues or costs related to Bruce facilities were excluded. Table 7 of Ex. F4-T2-S1 summarizes the result of the calculations for 2005-2007 in the tables referenced above and adjusts for the first quarter of 2008.

For purposes of illustration and ease of reference, OPG has prepared a simplified version of Table 7 of Ex. F4-T2-S1, which is presented in the table below:

[56] F4-T2-S1, Table 10 also shows the allocation to remove the first quarter of 2005, which was prior to the regulation of the prescribed facilities by the Province.

Table 1: Summary of Calculation of Tax Loss for April 1, 2005 to March 31, 2008

$M		OPG's Calculation				
Line No.	**Particulars**	**Q2-Q4 2005**	**2006**	**2007**	**Q1 2008**	**Total Prior Period**
1	Regulatory Earnings Before Tax	(2.3)	78.0	(231.1)	74.9	(80.5)
2	Operating Losses Borne by OPG's Shareholder	2.3	0.0	231.1	0.0	233.4
3	Adjusted Regulatory Earnings Before Tax	0.0	78.0	0.0	74.9	152.9
4	Segregated Fund Contributions net of Nuclear Waste Management Expenses	(166.5)	(220.1)	(199.8)	(9.5)	(595.9)
5	Pension and OPEB Expenses (excess of expenses over cash)	(1.4)	112.0	116.0	18.9	245.5
6	Nuclear Waste Expenditures net of Segregated Fund Receipts	(30.8)	(98.0)	(8.0)	(28.0)	(164.8)
7	Depreciation in excess of CCA	12.5	(2.8)	4.5	3.7	17.9
8	Unamortized PARTS Deferral Account	0.0	0.0	0.0	0.0	0.0
9	Nuclear Liability Deferral Account	0.0	0.0	0.0	0.0	0.0
10	Other Net Additions	120.7	46.2	49.0	17.6	233.5
11	Tax Loss / Net Amount Available to Ratepayers	(65.5)	(84.7)	(38.3)	77.6	(110.9)

Notes:

a. Line 1 = For 2005-2007, Line 1, Col (8) of Tables 10-12, respectively (2005 amount pro-rated by ¾)
b. Line 2 = For 2005-2007, Line 2, Col (8) of Tables 10-12, respectively (2005 amount pro-rated by ¾)
c. Line 3 = Ex. F4-T2-S1, Table 7, Line 1
d. Line 4 = Ex. F4-T2-S1, Table 7, Line 15 less Line 4 (2005 amounts pro-rated by ¾)
e. Line 5 = Ex. F4-T2-S1, Table 7, Line 6 less (Line 16 + Line 17) (2005 amounts pro-rated by ¾)
f. Line 6 = Ex. F4-T2-S1, Table 7, Line 14 less Line 5 (2005 amounts pro-rated by ¾)
g. Line 7 = Ex. F4-T2-S1, Table 7, Line 3 less Line 13 (2005 amounts pro-rated by ¾)
h. Line 10 = Ex. F4-T2-S1, Table 7, Lines 7 through 11 less Line 18 (2005 amounts pro-rated by ¾)

As shown in the Table 1 above, OPG had tax losses (Line 11) for the years 2005, 2006, and 2007 of $65.5M, $84.7M and $38.3M, respectively, for a total loss carry forward of $188.5M. Taxable income for the first quarter of 2008 was offset against the tax losses in prior years leaving a remaining tax loss of $110.9M. This was the amount of the tax loss available for mitigation in EB-2007-0905 as of March 31, 2008, and, as such, was the amount available to offset regulated taxable income for April 1, 2008 onward. This amount is consistent with the benefits follow the cost principle. The approach taken by OPG wholly satisfies the OEB's prior rulings and directions and is in accordance with accepted accounting, tax and regulatory principles.

11.1.4 Overview of Reply to SEC

In its submissions SEC concludes that there exist prior to April 1, 2008 total net tax deductions of $1,660.4M that can be used to reduce taxable income of OPG's regulated business (SEC argument, para. 10.2.96). This conclusion must be rejected by the OEB for the following reasons:

- it is based upon submissions that consist of untested evidence;
- it violates OEB approved regulatory principles;
- it does not comply with accepted tax and accounting practices; and
- it is based on misinterpreted facts and faulty assumptions.

SEC's submissions provide a complex analysis of a theoretical model applied to the tax returns and accounting data of OPG for the period 2005 to the end of Q1 2008. At its simplest, SEC's approach asserts that because OPG has gone from being unregulated to partially regulated, there may have been deductions taken in the period 2005 to the end of Q1 2008, which have not been made available to ratepayers. In SEC's view, these deductions are appropriately allocated to ratepayers to compensate them for later tax cost consequences because of differences in the timing of deductions for accounting and tax purposes.

Instead of addressing the determination of the appropriate amount of the TLVA, SEC instead presents a construct of its own making that is a complete revamping of the fundamental principles applied to regulatory tax calculations.

SEC's argument focuses on net deductions and not the application of those net deductions to earnings before tax ("EBT") in each of the applicable years. It focuses not on <u>tax losses</u>, but rather on the aggregation of net deductions, a concept not found in accepted regulatory, tax or accounting principles. In addition, SEC does not properly apply the benefits follow the cost principle and also does not follow the OEB's ruling with respect to Bruce revenues and costs. In sum, SEC does not properly incorporate any of the three components to OEB's rulings in EB-2007-0905 and EB-2009-0038.

SEC's submissions also ignore the provisions of Regulation 53/05 section 6(2) paragraphs 5 and 6. These provisions require the OEB to accept as part of its regulation of OPG the revenue requirement impact of accounting and tax policy prior to the effective date of the OEB's first Order (which was April 1, 2008).

11.1.5 SEC's Submissions Are Untested Evidence

It is important to note at the outset that SEC's submissions are in the form of expert/opinion evidence as to the workings of various accounting and regulatory principles related to tax/accounting timing differences. SEC offers no authority for the positions taken or support for any of the conclusions or the principles that it espouses. SEC, as did all participants, had the opportunity to file expert evidence, but did not. The statements made in SEC's argument are not authoritative and have not been subject to cross examination. The construct proposed by SEC (including its underlying assumptions) was not disclosed by SEC or known by any witness or party during the course of the hearing such that parties could dispute or even comment on them. At most, SEC's submissions present a theoretical construct and conjecture that is untested.

The OEB should give SEC's submissions no weight. Indeed, the OEB would be in error to rely on SEC's submissions as part of any decision related to the TLVA. The legal requirements to decide matters based on evidence in the record and to provide applicants with an opportunity to respond to contrary evidence are discussed above in section 1.0, Introduction.

11.1.6 Compliance with Accounting and Tax Principles and Use of Tax Loss

For all tax matters addressed in OPG's evidence, including the calculation of the regulatory tax losses for the period April 1, 2005 to March 31, 2008, OPG has consistently applied the same tax principles and methodology. These principles and methodology are based on the requirements of income tax legislation as modified by regulatory tax principles.[57] This methodology is consistent with the way OPG, and most other regulated entities, calculate their actual taxes payable.

OPG calculated taxable income/loss for each year by offsetting applicable net deductions against Earnings Before Tax ("EBT") and, where a tax loss existed, it was carried forward to the end of the period before the OEB's first Order (March 31, 2008). It is that amount, $110.9M, which was carried forward into the period when OEB regulation began.

SEC states that the "tax loss" concept is irrelevant and instead submits that the amount that should be carried forward is the "timing difference." (SEC argument, para. 10.2.33) Tax loss carry forward is a well recognized concept that forms part of the *Income Tax Act* (Canada) and related legislation and OEB regulated tax calculations (2006 Distribution Rate Handbook, p. 61; Report of the Board (RP-2004-0188) May 11, 2004, p. 57). Timing differences carried forward have no basis in accounting. The fact that SEC's construct is not based on accepted accounting, tax or regulatory principles or practices is sufficient reason, without more, for the OEB to reject SEC's approach.

Central to SEC's argument is the assertion that "timing differences" generally follow the pattern depicted in paragraph 10.2.14 of SEC's submission. This pattern is used by SEC to reinforce the notion that, typically, deductions for tax purposes occur before the associated expenses are recognized for accounting purposes. OPG disagrees that this generalization is correct. In fact, the depicted pattern is actuality limited to very specific items, most notably fixed assets (i.e., accounting depreciation expense versus CCA). However, there are other instances of timing differences that arise because certain items can only be deducted for tax purposes after they are expensed for accounting purposes.

[57] The applicable tax legislation is: *Income Tax Act* (Canada), *Taxation Act, 2007* (Ontario) and for taxation years ending prior to January 1, 2009, the *Corporations Tax Act* (Ontario), as modified by the *Electricity Act, 1998* and related regulations

Examples include almost all allowances, provisions and reserves such as the allowance for doubtful accounts, provisions for potential legal and environmental costs, and asset retirement obligations (“ARO”).

OPG’s witnesses specifically testified that the pattern of “early tax deductions” painted by SEC may or may not apply to particular circumstances (Tr. Vol. 14, pp. 74-76). For instance, OPG has significant Nuclear Liabilities (or ARO), which are deductible only when actual cash expenditures are made (Ex. F4-T2-S1, sections 3.3.2 and 3.3.3). For Pension and OPEB, accounting expenses have generally exceeded cash payments, and hence the timing of tax deductibility has lagged the timing of expenses recognition for accounting purposes. As a result, there is no basis to conclude that the “typical” pattern cited by SEC applies to OPG’s specific timing differences and there is strong evidence that it does not.

Fundamentally, it is the OEB’s regulatory objective to establish just and reasonable rates based upon a revenue requirement, and it has been OEB’s practice to establish the revenue requirement for cost-of-service regulation through accounting and taxation principles, modified by regulatory principles. In doing so, where there is taxable income that would give rise to a tax allowance in rates, the OEB has found that any previous tax loss that remains available should be carried forward and used to offset taxable income, thereby minimizing the tax allowance.

The whole premise behind having net tax additions or deductions is that they are additions or deductions against something, and that “something” is earnings or loss before tax (i.e., accounting income). These additions or deductions adjust earnings before tax to arrive at taxable income or a tax loss. Taxes payable are a function of taxable income, not deductions or additions (i.e., timing differences). The timing differences do not exist in a vacuum, and so their benefit cannot be considered without considering EBT and taxable income. Entities are not taxed on timing differences, but instead on taxable income. This is a basic premise for all tax calculations, including regulatory tax calculations. There was no disagreement on this between OPG’s witnesses and SEC’s counsel. In fact, this proposition was advanced by SEC’s counsel to OPG’s witnesses. (TR. Vol. 14, pg. 118, lines 1-7)

> MR. SHEPHERD: The taxable income or loss is a combination of three numbers; right? The accounting income or loss, the add-backs and the deductions?
>
> MR. HEARD: That's correct.
>
> MR. SHEPHERD: Okay. So if you change any one of them, you change the taxable income or loss, don't you?
>
> MR. HEARD: Yes.

Adoption of the SEC construct would require the OEB to abandon established practice accounting principles. SEC focuses only on timing differences (Lines 4 through 10 in Table 1, above) and ignores earnings before tax (Lines 1 through 3). OPG applies the deductions against EBT and carries forward any resulting loss. SEC, on the other hand, ignores EBT and does not apply the deduction in the period for which it applies.

11.1.7 Ratepayers Have Received the Benefits of the 2005-2008 Deductions

Despite SEC's assertions to the contrary, the concept of tax losses is relevant here. A number of the deductions that SEC states belong to ratepayers have already been provided to ratepayers (as shown in Table 2 below) through OPG's calculation of tax losses and the carry forward of those tax losses for use in the period starting on April 1, 2008. The benefits of the deductions have been included in the calculation of tax losses of $110.9M for the period April 1, 2005 to March 31, 2008. SEC merely disregards this fact.

11.1.8 Pre-2005 Period

SEC further asserts that there are possible other net timing difference amounts arising from the period prior to April 1, 2005 that belong to ratepayers and should be used to reduce OPG's tax costs in setting future payment amounts. SEC requests that OPG be directed to file a report with respect to the pre-April 1, 2005 amounts (SEC argument, paras. 10.2.109 – 10.2.111). SEC also requests that OPG file a report on Pension/OPEB timing differences in 2005-2008 period to determine which of them relate to periods before and which relate to periods after April 1, 2005 (SEC argument, para. 10.2.74).

OPG submits that the OEB should reject SEC's requests. OPG's facilities were wholly unregulated prior to April 1, 2005. The concept of prescribed facilities did not exist.

Based upon the stand-alone principle, any benefit arising from deductions would be wholly to the shareholder's benefit. There is absolutely no basis whatsoever to conclude that periods prior to the prescribed facilities becoming regulated by the Province on April 1, 2005 could be subject to review by the OEB.[58] The OEB would be in error to do so. With respect to the issue of the 2005-2008 Pension/OPEB expense, see Section 11.1.9 below where the timing differences for Pension/OPEB are addressed.

Based upon the forgoing and also on the OEB's prior rulings, the period prior to April 1, 2005 is not in question and should not enter the analysis of the balance of the Tax Loss Variance Account or OPG's future calculations.

11.1.9 Incorrect Analysis by SEC

In addressing the specific conclusions of SEC's analysis and the flaws contained therein, OPG has modified Table 1 above to incorporate SEC's summary table (SEC argument, para. 10.2.96). OPG has only included that part of SEC's summary table totaling $1,052.4M (the portion of $1,660.4M related to prescribed facilities). As noted above, SEC completely disregards the OEB's ruling related to the treatment of Bruce revenues and cost and the fact they are not included in the determination of regulatory taxable income or loss. As a result, that column of SEC's summary table should be ignored and OPG does so in Table 2 below.

[58] The OEB has already held that "absent clear and express direction to the contrary [in O. Regulation 53/05], the Board does not have the jurisdiction to review or order recovery of pre-April 2008 costs." (Decision with Reasons, EB-2007-0905, p. 120).

Table 2: Summary of OPG and SEC Calculations

$M		OPG's Calculation					SEC's Calculation
Line No.	Particulars	Q2-Q4 2005	2006	2007	Q1 2008	Total Prior Period	Total Prior Period[1]
1	Regulatory Earnings Before Tax	(2.3)	78.0	(231.1)	74.9	(80.5)	0.0
2	Operating Losses Borne by OPG's Shareholder	2.3	0.0	231.1	0.0	233.4	0.0
3	Adjusted Regulatory Earnings Before Tax	0.0	78.0	0.0	74.9	152.9	0.0
4	Segregated Fund Contributions net of Nuclear Waste Management Expenses	(166.5)	(220.1)	(199.8)	(9.5)	(595.9)	(595.7)
5	Pension and OPEB Expenses (excess of expenses over cash)	(1.4)	112.0	116.0	18.9	245.5	0.0
6	Nuclear Waste Expenditures net of Segregated Fund Receipts	(30.8)	(98.0)	(8.0)	(28.0)	(164.8)	(213.9)
7	Depreciation in excess of CCA	12.5	(2.8)	4.5	3.7	17.9	0.0
8	Unamortized PARTS Deferral Account	0.0	0.0	0.0	0.0	0.0	(112.3)
9	Nuclear Liability Deferral Account	0.0	0.0	0.0	0.0	0.0	(130.5)
10	Other Net Additions	120.7	46.2	49.0	17.6	233.5	0.0
11	Tax Loss / Net Amount Available to Ratepayers	(65.5)	(84.7)	(38.3)	77.6	(110.9)	(1,052.4)

[1] The simplifying assumption in SEC's calculation of using 25 per cent of annual 2008 amounts provided in Ex. L-01-120 to estimate Q1 2008 amounts (para. 10.2.46 (b)) is unnecessary and, in certain instances, results in materially inaccurate numbers that are higher than the actual net deductions/losses available to ratepayers. In Ex. F4-T2-S1, Table 7, column (d), OPG provides a calculation specific to Q1 2008. Based on this difference alone, OPG's total amounts for the prior period will differ from SEC's.

Each of the lines in Table 2 is considered below.

Earnings Before Tax

As noted above, a fundamental error in SEC's analysis is that it ignores EBT. OPG's approach, however, works within the accepted OEB practice of employing standard tax and accounting treatment. OPG applies the deductions against regulatory EBT (Line 3 of Table 2) and carries forward any resulting tax loss (Line 11 of Table 2). It is worth noting that SEC correctly states in paragraph 10.2.51 that the total net deductions for the period April 1, 2005 to March 31, 2008 were used to reduce positive earnings before tax in computing taxable income or loss. But, then, in the next paragraph (10.2.52), without explanation, SEC goes on to state: "The question to be addressed, in our submission is how much of that $1,164.1 million of timing differences represents tax benefits for costs that the ratepayer will bear." OPG submits that "the correct question" is how much of the EBT relates to regulated operations for each period from April 1, 2005 to March 31, 2008, and what deductions applicable to regulated operations should be applied to EBT to reduce that amount for the benefit of the ratepayers. SEC's analysis fails to do that.

OPG's analysis of regulatory earnings before tax is also a prime example of the application of "benefits follow costs" principle and its compliance with OEB's findings in EB-2007-0905. Specifically, in each of 2005 and 2007, OPG's prescribed facilities experienced operating losses (i.e., losses before tax), with the loss in 2007 of $231.1M being by far the bigger of the two amounts (as shown in Line 1 of Table 2). The loss was due to lower actual nuclear production than the forecast provided to the Province for setting interim rates, and since OPG's Shareholder was not compensated by the ratepayer for the lower production and lost revenue, the related tax benefit should go to the Shareholder (Ex. F4-T2-S1, p. 16). As such, OPG removed this operating loss in Line 2 of Table 2 above to arrive at the adjusted regulatory earnings before tax that are attributable to ratepayers (Line 3 of Table 2).

Net Deductions Related to Nuclear Liabilities and Segregated Funds

The deductions for segregated fund contributions and the addition of accruals for nuclear waste management expenses are presented as a net amount at Line 4 of Table 2. Both OPG and SEC recognize that this amount accrues to ratepayers. These items already form part of OPG's tax calculations for income tax return purposes, and OPG has attributed these deductions for the prescribed facilities to the ratepayers in its analysis of the tax returns.

OPG took a similar approach to the net deduction for nuclear waste expenditures net of segregated fund receipts presented at Line 6 of Table 2 (the difference in the OPG and SEC amounts is due to a computational error in SEC's calculation and the more precise amount used by OPG for Q1 2008). These amounts also represent a net deduction in OPG's analysis. OPG attributed the tax deduction for the prescribed facilities to ratepayers.

Pension and OPEB Expenses

SEC attributes no value to Pension and OPEB accrual expenses (net of pension fund contributions and OPEB payments) (Line 5 of Table 2). This is incorrect. A net addition for Pension and OPEB expenses is appropriate and accords with the "benefits follow costs" principle since the ratepayers paid for Pension and OPEB expenses during the period in question. By treating it as a net addition, OPG is simply passing the tax impacts of these expenses to ratepayers in accordance with income tax legislation, which is how the actual taxes payable by OPG are calculated. As noted in Ex. F4-T2-S1, section 3.3.5, the accounting expenses for Pension and OPEB are not deductible for income tax purposes, whereas cash contributions and payments are.

SEC submits that Pension and OPEB is an example where net tax costs "probably" relate to a prior period due to OPG's aging work force. (SEC argument, para. 10.2.72) This conclusion is wrong. The very fact that OPG's accrual expenses exceed the cash payments means that timing differences have not yet reversed because, in the reversal stage, cash payments would have to be the higher of the two amounts.

Depreciation in Excess of CCA

In attributing no value to the net of the depreciation addition and the CCA deduction for tax purposes (Line 7 of Table 2), SEC makes a number of statements that are unfounded and incorrect. The essential elements of SEC's argument are that CCA is lower than depreciation; that OPG's Shareholder has enjoyed significant CCA benefits in earlier years and that the ratepayers are currently bearing a cost for which they did not get a benefit.

The premise is faulty. SEC ignores the fact that a significant portion of OPG's nuclear fixed asset value and consequently depreciation relates to Asset Retirement Costs ("ARC"). Once adjusted for ARC depreciation, CCA is significantly greater than depreciation. As a result, SEC is incorrect in claiming that OPG has somehow "crossed over" into a period where previously taken net deductions for CCA are reversing.

To be clear, there is a net deduction of $308.6M with respect to CCA and depreciation, once ARC is excluded, for the period April 1, 2005 to March 31, 2008 for the prescribed facilities. This deduction has been passed on to ratepayers in OPG's calculation of the tax loss of $110.9M. With respect to ARC depreciation, there is no CCA available to OPG under tax legislation, and ratepayers receive the tax benefit of funding the tax cost of ARC depreciation through the deduction for segregated fund contributions (Tr. Vol. 14, p. 147).

The second flaw is SEC's suggestion that the portfolio effect, which balances the tax benefits from new capital spending against the net tax costs associated with older assets, somehow does not apply to OPG because it is a generation utility (SEC argument, paragraph 10.2.77). While, overall, generators' capital spending tends to be lumpier, SEC ignores OPG's specific circumstances. For example, OPG added $536.0M to its nuclear fixed assets during 2005, which, excluding the opening net book value of ARC, represents almost 50 per cent of the opening net book value of prescribed nuclear fixed assets for 2005 (EB-2007-0905, Ex. B3-T3-S1, Table 1; EB-2007-0905 J15.1 Addendum #2) Such a significant amount of additions created significant net deductions for depreciation/CCA for at least several years. The significant in-service addition amount for the Niagara Tunnel will produce a similar effect.

PARTS Deferral Account

OPG and SEC agree that ratepayers should receive a tax benefit from the deduction for the expenditures recorded in the PARTS Deferral Account. The point of disagreement is how this is accomplished. OPG's approach provides the PARTS expenditures deduction over time to match the recovery of the deferral account from ratepayers. This approach is appropriate and accords with the "benefits follow costs" principle. SEC acknowledges that the ratepayers are getting the benefit of the PARTS deduction in paragraph 10.2.88, albeit over time. However, in paragraph 10.2.89, SEC disagrees with the approach taken by OPG. SEC appears to assert that the deduction should be provided at the time it is claimed on OPG's tax returns, rather than as the underlying costs are recovered from ratepayers. SEC asserts that based on its approach, there would be an additional deduction of $112.3M for the PARTS Deferral Account.[59]

OPG's witnesses went to great lengths to address this issue during cross-examination (Tr. Vol. 14, pp. 119-121). OPG's witness made clear that the deduction flows to ratepayers over the period 2005 to the end of the amortization period in 2011.

OPG's approach is based upon the OEB's direction in the EB-2007-0095 Decision (p. 170), which required that the timing of PARTS recovery match the timing of providing the associated tax cost or benefit to ratepayers. OPG's witnesses also explained that the company applies this principle consistently to the tax treatment of all of its variance and deferral accounts and that this approach also works to protect ratepayers from having to compensate OPG for taxes in situations when OPG has to pay taxes before it fully recovers account balances from ratepayers, as is the case with the Bruce Lease Net Revenues Variance Account. (Tr. Vol. 14, pg. 121) This approach is further explained in section 3.4 of Ex. F4-T2-S1.

Nuclear Liability Deferral Account

SEC suggests that the balance of this account should be provided as a deduction to ratepayers. OPG disagrees because the benefit SEC claims is almost entirely nonexistent. OPG's evidence is clear that this adjustment would attribute a tax deduction to ratepayers where none exists because the balance in the Nuclear Liability Deferral Account is mostly not deductible for tax purposes. As a result, as OPG has explained in detail, there is no benefit that could be passed on to ratepayers (with a small exception

[59] OPG cannot identify the basis for $112.3M figure, and SEC does not cite the source. Should the Board accept SEC's position, the amount of adjustment to the TLVA would be only with respect to the unrecovered portion of the deferral account as a December 31, 2010 of $33.1M (Ex. H1-T2-S1, Table 2, Line 1, Col. (c)). This is because OPG's calculations of tax expense for 2008-2010 underlying the TLVA already provide the tax benefit of the deferral account portion recovered during the period April 1, 2008 to December 31, 2010.

that is already being provided to ratepayers) (Ex. F4-T2-S1, p. 10; Tr. Vol. 14, pp. 147-148).[60] Finally, SEC's statement at paragraph 10.2.93 that "this amount is in fact an amount that generated a 2007 tax deduction" is wrong.[61]

Other Net Additions

The incomplete nature of SEC's analysis is further highlighted by the fact that it ignores other adjustments to earnings before tax for the prescribed facilities that are, in fact, additions rather than deductions, on a net basis. These net additions total $233.5M, as per Line 10 of Table 2. SEC offers absolutely no basis whatsoever for excluding these items, while picking others that are favourable to SEC's position. As an example, SEC has ignored the one-time additions for Pickering A Units 2&3 Inventory Write-offs and CIP Write-offs in 2005 that total $87.0M, which OPG did not recover from ratepayers and, consequently, for which OPG is not passing the associated tax benefit consistent with the "benefits follow costs" principle (EB-2007-0905, Ex. F3-T2-S1, pp. 10-11). OPG submits that the tax cost of these and other net additions is consistent with the "benefits follow costs" principle.

Conclusion Regarding Table 2

OPG has analyzed SEC's claims to show that they are flawed, unfairly "cherry-pick" only matters favourable to SEC's position and do not represent a realistic view of OPG's tax obligations or available deductions. The examples above further reinforce the fact that the OEB cannot rely on this untested and inaccurate information to establish the appropriate balance in the TLVA.

11.1.10 Additional Arguments of CME

CME submissions on the TLVA (paras. 210 – 235) support the submissions of SEC, address the continuation of the account in 2010 (addressed in section 11.1.12 below)

[60] The capital tax component of the account balance and interest improvement on the balance are the two tax-deductible items. They represented $6.6M of the $130.5M balance as at December 31, 2007 (EB-2007-0905 Decision with Reasons, pg. 94, Table 5-6). The deduction for these amounts is included in OPG's regulatory tax calculations over the 33 months starting on April 1, 2008, consistent with the recovery period of the Nuclear Liability Deferral Account (Ex. F4-T2-S1, Table 9, Line 16).

[61] SEC's assertion in para.10.2.95 that OPG took a deduction for the Nuclear Liability Deferral Account on its 2007 income tax return is wrong. While there is a line showing this amount in the deductions section on the tax return presented at line 23 in the reconciliation table for 2007 at Ex. F4-T2-S1 Attachment 1, there is a corresponding addition embedded in that table in lines 2 and 3.

and set out an alternative approach to consideration of the amount of the TLVA balance for the period ending December 31, 2009. This section addresses this alternative approach. As an overall observation, OPG submits that CME has mischaracterized OPG's original proposal in EB-2007-0905 with respect to tax losses and mitigation and appears to either misrepresent or not really understand the nature of the TLVA. This leads to an incorrect description of the OEB's Decision on the scope of the TLVA as set out in EB-2009-0038. CME also misrepresents the OEB's directions with respect to taxes in EB-2007-0905.

CME's fundamental mistake is stating that the issue in EB-2009-0038 was the appropriate amount of mitigation of rates established in EB-2007-0905 (para. 222). In fact, what was at issue was that the mitigation OPG had offered was linked to tax loss carry forward amounts and that the Payments Decision in EB-2007-0905 failed to recognize that linkage. The Decision in EB-2009-0038 found that there was a link and varied the Payments Decision "in a manner that links the revenue requirement reduction and regulatory tax losses" (Decision and Order, EB-2009-0038, p. 15). It then ordered the establishment of the TLVA as the mechanism to reverse the impact of this error.

As stated in section 11.1.1, the amount of $341.2M is the amount of mitigation that was included in the payment amounts arising from the order in EB-2007-0905, and is not in dispute. It is not a "gross up for taxes" as CME claims (paras. 210, 213). This amount comprises mitigation in the amount of 22 per cent of the deficiency and the elimination of any tax provision for 2008 and 2009 (including the appropriate gross-up for taxes) (Decision with Reasons, EB-2007-0905, p. 171). OPG explained this at the Technical Conference at some length (Technical Conference Tr., pp. 137-139; see also Ex. KT1.8; L-5-30).

CME continues to mischaracterize the nature of OPG's proposal in EB-2007-0905 as focused on achieving a certain amount of mitigation as an end result (CME argument, paras. 220–222). As stated above, this was not the case and was found not to be the case in the subsequent Motion Decision. The proposed mitigation in EB-2007-0905 was linked to the prior period tax loss calculation.

In as much as OPG's integrated tax loss proposal was not "pure" mitigation, it is even further from the truth for CME to claim an "implied agreement between OPG and parties opposite in interest that the mitigation amount should be quantified in the order of $228M." What CME is suggesting by invoking the words "implied agreement" is that OPG is now somehow bound to give up the $228M in any event. Not only does OPG reject this, but it has been litigated by CME and others in EB-2009-0038 and their position was rejected by the OEB. CME should not be allowed to re-litigate the issue in this proceeding.

Similarly, CME's statement that "The decision [on the Motion] was primarily about whether or not a tracking account was needed to achieve the objective of deferring the quantification of the mitigation amount to a future proceeding" is simply wrong (CME Argument, para. 222). The Decision in EB-2009-0038 established an account to record any variance between the tax loss mitigation amount that underpins the last rate order and the tax loss amount resulting from the re-analysis of the prior period tax returns based on the OEB's direction in EB-2007-0905. The variance account deals with the variance due to differences in tax loss amounts. The account does not deal with what is an appropriate "mitigation amount".

CME implies that the OEB made a finding in EB-2007-0905 that OPG did not follow the "benefits follow costs" principle in its tax calculations (CME Argument, paras. 225, 227). This is not true. The OEB found that it did not have sufficient evidence or analysis to make a determination whether the principle was followed appropriately. It required OPG to file better information in its next proceeding (see EB-2007-0905, pp. 170-171). OPG submits that while it made changes to the tax loss calculation, these were made only to apply the specific guidance provided in the OEB's decision with respect to the application of benefits follow costs to certain items (e.g., operating loss, treatment of Bruce revenues and costs) and address the OEB's request for more and better evidence with respect to OPG's tax calculations.

OPG disputes CME's submissions with respect to determining the appropriate TLVA balance based on the need for additional mitigation for the reasons set out above (CME argument, paras. 230-231). The TLVA is not about the right level of mitigation in EB-

2007-0905. Even were this not the case, CME's calculations, introduced for the first time in its submission, are of no value. For example, the revenue deficiency of $1,025.7M that CME cites from EB-2007-0905 was based on OPG's originally proposed treatment of the Bruce revenues and costs and nuclear liabilities, which differs from that ultimately determined by the OEB and used in the present application.

11.1.11 Continuation of the Tax Loss Variance Account in 2010

OPG recorded an addition of $195.0M in 2010 to the TLVA (Ex. H1-T1-S1, Table 4). This is an annualized value (12/21) based on the $341.2M revenue requirement reduction incorporated in the payment amounts for the 21-month test period in 2008 and 2009 in EB-2007-0905.

VECC (pars.113–124), supported by SEC (para. 10.2.101) and CME (para. 232), submits that the TLVA should not continue in 2010. There is no logic to this argument. The Decision in EB-2009-0038 determined that there was an error in the payment amounts established in EB-2007-0905. The Tax Loss Variance Account was the mechanism established to correct this error. Since the payment amounts established in EB-2007-0905 continued, the error embedded within them continued and the need to correct this error through the TLVA also continued. There is no basis for the proposal that the error should be corrected in 2008 and 2009 and then ignored in 2010.

The basis for VECC's argument is that the OEB Decision establishing the TLVA in EB-2009-0038 does not contemplate the operation of this account beyond 2009. VECC posits that the OEB approved TLVA only for 2008/2009, and that the 2010 forecasted recovery which OPG seeks in this application is for "a different account than the 2010 Tax Loss Variance Account that OPG never brought before the Board." (VECC argument, para. 120).

In large part, OPG has already replied to VECC's argument in interrogatory L-14-38. VECC asked for the "legal basis upon which OPG believes it is entitled to claim relief in the TLVA based on 2010 payments." In the interrogatory, as repeated in its submissions (para.115), VECC places great emphasis on words in the EB-2009-0038 Decision that read "for the test period" in the excerpt below:

> The Board varies the Payments Decision in a manner that links the revenue requirement reduction and regulatory tax losses, and orders the establishment of a tax loss variance account to record any variance between the tax loss mitigation amount which underpins the rate order for the test period and the tax loss amount resulting from the re-analysis of the prior period tax returns based on the Board's directions in the Payments Decision as to the re-calculation of those tax losses.

OPG's Reply is in essence the same as its answer to the interrogatory. That is, payment amounts are established based on a test period, but they remain in place until changed by the OEB. Similarly, unless the OEB explicitly states otherwise, variance and deferral accounts established in relation to those payment amounts also continue until changed by the OEB. The continuation of the TLVA illustrates the operation of this principle. The payments amounts established in EB-2007-0905, which include the identifiable error found in EB-2009-0038, continue into 2010. The TLVA created by the OEB's Order in EB-2009-0038 to correct this error also continues into 2010 because the OEB's Order does not include an explicit end date for this account.

In response to VECC's interpretation of the excerpt from EB-2009-0038 set out above, OPG submits that the words "for the test period" do not represent a specific time limitation for the TLVA but simply describe the fact that variance account records the difference resulting from payment amounts determined on the basis of the revenue requirement from the payment amounts order in EB-2007-0905 (which was approved for the test period) and the revenue requirement recalculated to correct the identified error. If the OEB had clearly intended to put an end date on the TLVA, it would have said it much more explicitly, particularly in light of the principle that accounts continue until they are changed by the OEB.

Moreover, and more importantly, were VECC's interpretation of this passage from the Decision to be a correct one, the OEB would have spelled out an end date in the OEB's actual Order (at p.16) in EB-2009-0038. Instead, the Order provides that:

> 2. OPG shall establish a variance account to be called the Tax Loss Variance Account to be effective as of April 1, 2008;

As between the Order and the Reasons, the Order is the governing document. As set out in section 19(2) of the *Ontario Energy Board Act*, *1998:* "the Board shall make any determination in a proceeding by order." This is consistent with the law in relation to appeals where courts have held that a party may only appeal from an order, and not from the related reasons.[62]

Further, OPG submits that to the extent VECC wishes to interpret the scope of the TLVA by reference to the Reasons, as opposed to the Order, at least as much weight should be given to the part of the Reasons that reads, "As noted above, the Board has determined that identifiable errors that are material and relevant to the outcome of the reviewed decision have been made." (p.15) In OPG's submission, the focus in this application should be on substantive decisions to correct the identifiable errors, which have continued into 2010, a fact that VECC does not dispute.

OPG expanded on the foregoing during cross examination (Tr. Vol. 14, pp. 99 -109). In response to questions posed by SEC, OPG confirmed that it deliberately did not include the account in the accounting order application in EB-2009-0174 because OPG did not believe any clarification was necessary on how to do the math for the entries in the TLVA.

In OPG's view, there was no need to address the TLVA in EB-2009-0174 because no relief was needed from the OEB in respect of the TLVA. OPG did not "hide" or "avoid" the TLVA in EB-2009-0174 and it was certainly open to the intervenors in that proceeding (who have intervened in this proceeding also) to raise issues about it or seek clarity respecting it.

In cross-examination, SEC suggested that telling the OEB in the accounting order proceeding that OPG would be seeking to continue the TLVA and would be seeking an amount such as $195M might influence the decision on the accounting order, and this is why OPG did not ask for a continuation of the account. In its argument, CME has also seized on this suggestion (CME argument, para. 214). In cross-examination, Mr. Barrett addressed this suggestion by stating that EB-2009-00174 was about the mechanics of booking entries and the continuation of a rider to recover an amortization already approved by the OEB. The accounting order does not extend the term of any of OPG's

[62] *Canadian Express Ltd. v. Blair* (1991). 6 O.R. (3d) 212 (Div. Ct.)

variance accounts because to do so would have been unnecessary, and the OEB accepted that it was unnecessary (Tr. Vol. 15, p. 108).

CME's claim that the fact that OPG is seeking approval for the continuance of the TLVA in this proceeding discredits OPG's argument that the TLVA continues beyond 2009 without an OEB order is incorrect (CME argument, para. 232). This proceeding is a full cost-of-service application. The Filing Guidelines for this proceeding state that OPG should address all of its deferral and variance accounts, including those it wishes to be in place after the date of the OEB's order. No similar requirement governs OPG's request for an accounting order.

11.1.12 Conclusion

Based upon the forgoing OPG submits that SEC's construct and its submission should be rejected by the OEB, as should the additional submissions of CME. OPG's proposal follows OEB's rulings and direction, accords with regulatory, tax and accounting principles applicable to regulatory tax and correctly provides the benefit of applicable deductions to ratepayers. OPG further submits that the 2010 entries in the account are consistent with the Decision creating the account. As such, its approach to the TLVA and the proposed balance for clearance should be accepted.

11.2 BRUCE LEASE NET REVENUES VARIANCE ACCOUNT

Board staff has proposed that the balance in this account be recovered over a period of 46 months rather than over 22 months as proposed by OPG. The basis of this submission seems to be Board staff's view that further rate mitigation is required. However, they offer no real substantiation for this view or indicate what the "target" level of rate increase should be. They also don't acknowledge the impact that deferring the recovery of this money will have on OPG. As indicated in interrogatory response Ex. L-01-146, the setting of recovery periods for variance accounts with large balances involves a balancing between the potential impacts on ratepayers and the need to clear accumulated balances in a timely manner.

In addition, there is no consideration by Board staff that extending the term of this account will add to the rate pressure in the next test period. In OPG's submission, simply pushing off costs into the future is not always the right answer.

In OPG's submission, the extended recovery period for the balance in the Tax Loss Variance Account should provide sufficient rate mitigation (Tr. Vol. 15, p. 68). It contributes to bringing down the average payment amounts increase sought to 6.2 per cent. This is a very reasonable level of increase given that rates for OPG were last set as of April 1, 2008.

Board staff also make the submission that the recovery period for this account should be "in line" with the recovery period for other accounts with large balances. In addition to citing the Tax Loss Variance Account, Board staff also cite the 45-month recovery period for the Pickering A Return to Service ("PARTS") account (Board staff argument, p. 93). The comparison to the authorized recovery period of that account is inapposite because of the unique circumstances that gave rise to the PARTS account. The longer recovery period stemmed from OPG's own proposal in EB-2007-0905 to recover the balance over 12 years. OPG sought to relate the recovery period to the underlying long-lived asset (i.e., Pickering A) and proposed that the carrying cost be set at the weighted average cost of capital, which is significantly higher than the generic interest rates for variance and deferral accounts prescribed by the OEB. The OEB rejected OPG's proposal; the recovery period was shortened to 45 months and the OEB's generic interest rate was applied. These unique circumstances distinguish the PARTS account from the Bruce Lease Net Revenues Variance Account.

OPG rejects the general proposition put forward by Board staff that all accounts with large balances should be recovered over a period longer than the next test period. In OPG's submission, judgment should be applied rather than simple rules when determining the recovery period for such accounts given the need to balance the impacts on ratepayers and the applicant. OPG questions whether Board staff would be recommending a longer disposition period if the balance in the account had been a credit back to ratepayers.

SEC has also proposed a 46-month recovery period for the balance in this account (SEC argument, para. 10.2.121). SEC's reasoning is that since balance is, in its view, largely due to "one-time unusual events" asking ratepayers to pay the account balance back over the next two years is not consistent with the original intention for the account (SEC argument, para. 10.2.120).

In OPG's submission, the OEB's Decision in the last proceeding was clear on the need for the Bruce Lease Net Revenues Variance Account and what should be recorded in it (EB-2007-0905, p. 112). Thus, it is unnecessary for the OEB to again inquire into the original intention of the account or to consider whether the balance in the account is due to "one-time unusual events." It is noteworthy that SEC cites no evidence to support its submissions regarding the "original intention" of the account. Accordingly, SEC's submission should be rejected.

11.3 CAPACITY REFURBISHMENT VARIANCE ACCOUNT

Board staff submits that OPG does not <u>need</u> to use the Capacity Refurbishment Variance Account for the Pickering B Continued Operations initiative because the company is "quite confident" in its budget for this initiative (Board staff argument, pp. 60-62). This is a naive submission that should be disregarded. The account is in place pursuant to the O. Reg. 53/05 and the Pickering B Continued Operations initiative clearly falls within the defined scope of the account because it is being undertaken to increase the output of the stations (Tr. Vol. 15, p. 50). OPG notes that its evidence on the scope of the account and that Pickering B Continued Operations falls within it were never seriously challenged in cross-examination or in argument.

Given these facts, it makes no sense to exclude the initiative from the scope of the account. Even activities for which there is high confidence in the budget forecast can have a variance, positive or negative, due to unforeseen developments or other reasons. It would be unfortunate, if the Pickering B Continued Operations initiative came in under-budget and the resulting credit balance was not returned to ratepayers via this account.

Board staff also argues that if the OEB believes using the Capacity Refurbishment Variance Account is appropriate for the Pickering B Continued Operations initiative, the account should be limited to only the fuel channel life cycle management project aspect of it. Again, OPG disagrees. The account should be used for the entire project since the entire project falls within the account definition that was established by the OEB.

In EB-2007-0905, the OEB directed OPG to establish the Capacity Refurbishment Variance Account effective April 1, 2008 as set out in Appendix F (page 5) to the Payment Amounts Order dated December 2, 2008. In that part of the Order, the OEB determined the account as follows:

> Capacity Refurbishment Variance Account
> OPG shall establish a Capacity Refurbishment Variance Account pursuant to O. Reg. 53/05 section 6 (2) 4 to 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 generation facility referred to in O. Reg. 53/05 section 2 during the test period and those forecast costs approved by the OEB. This account shall include assessment costs and pre-engineering costs and commitments.

Given that the entire Pickering B Continued Operations initiative, not just the fuel channel component, is directed to increasing “the output of” the Pickering Stations there is no regulatory or legal basis for excluding the balance of the activities from the account.

In their discussion of this account, Board staff also expresses a concern over the range of estimates for the Pickering B Continued Operations initiative (Board staff argument, p. 60). For some reason Board staff is unable to distinguish between numbers that appear in press releases and sustainability reports and the testimony of the senior OPG executive that is actually accountable for the project. As Mr. Pasquet explained at the Technical Conference the $300M figure was far from a precise project estimate:

> The public announcement really provides a conservative upper bounds for continued operations at the site. The actual cost included an upper range of confidence, and then was subsequently rounded up to $300 million (Technical Conference Transcript, p. 56).

In contrast, Mr. Pasquet was clear that $190M was OPG’s best cost estimate for the initiative and this is the figure that is supported by OPG’s detailed business case summary (Technical Conference Transcript, pp. 55-56; Ex. F2-T2-S3, Attachment 1).

Board staff also seems troubled by the fact that there is no contingency built into the cost estimate for the Pickering B Continued Operations initiative (Board staff argument, p. 62). However, there is a perfectly reasonable explanation for this fact. As Mr. Pasquet explained, since the vast majority of the work covered by this initiative is work that OPG has done before there exists a very good track record of information on which to base the cost estimate (Tr. Vol. 4, p. 125). This lack of contingency is also consistent with OPG's overall approach to budgeting for projects. As explained in OPG's AIC (pp. 23-24), OPG does not include contingencies within nuclear project budgets and project managers are only able to access additional monies to deal with contingencies after going through a rigorous challenge process (Tr. Vol. 5, pp. 158-160).

Board staff closes its discussion of the cost estimate and contingency issue by submitting that OPG will have to demonstrate that any cost overruns for this initiative, should they occur, are prudent before OPG would be able to recover them (Board staff argument, p. 62). OPG understands and accepts this burden and submits that this is true of every activity covered by a variance account.

To the extent that AMPCO's submissions to "support the approach to Pickering B continued operations proposed by Board staff" relate to the Board staff arguments outlined above, OPG's reply to Board staff also replies AMPCO (AMPCO argument, para.183).

AMPCO also argues for a disallowance of $4.9M from the balance in the Capacity Refurbishment Variance Account to reflect OPG's "shareholder's responsibility for the imprudence of these expenditures" related to the Pickering B Refurbishment project (AMPCO argument, paras. 162-165). AMPCO claims that this amount is based on CNSC costs associated with its review of OPG's environmental, safety and economic studies on the viability of refurbishing Pickering B that should not have been incurred (Ex. L-07-023). AMPCO cites no evidence to support the proposed disallowance or explain how the specific amount proposed was derived. Other than a bald assertion that "it is clear that it was never worthwhile to study refurbishment of Pickering B," AMPCO offers no basis for finding that OPG's activities were imprudent (Ibid., para. 164).

In reply, OPG submits that it undertook its evaluation of Pickering B refurbishment pursuant to a directive from its shareholder (Ex. D2-T2-S1, Attachment 5). This directive included specific direction to begin the environmental assessment for Pickering B Refurbishment. The OEB reviewed and approved OPG's proposed spending on Pickering B Refurbishment in the last proceeding (EB-2007-0905 Decision, pp. 37-38). In light of these facts, no possible basis exists for a finding that OPG's decision to undertake the environmental assessment or the studies necessary to evaluate Pickering B Refurbishment was imprudent.

OPG's environmental assessment was accepted by the Canadian Nuclear Safety Commission ("CNSC") on January 26, 2009. The report concluded that: "taking into account the identified mitigation measures, the refurbishment and continued operation of Pickering B nuclear station is not likely to cause significant adverse environmental effects." OPG also submitted an Integrated Safety Review, comprising more than 2,000 pages of documentation, and a Global Assessment to the CNSC in September, 2009. The purpose of the Integrated Safety Review was to assess the plant and the adequacy of programs as compared to current codes and standards (Tr. Vol. 4, p 34). The conclusion from this review was that the existing Pickering B station demonstrates a high level of compliance with current codes and standards, and can be operated safely today, and in the future should the decision be made to refurbish the plant. OPG's economic feasibility studies also provided information that was useful for the Pickering B Continued Operations initiative (Tr. Vol. 7, p. 41).

OPG submits that its activities with respect to Pickering B Refurbishment were conducted pursuant to shareholder direction and carried out in a prudent manner. As a result, the Board should reject AMPCO's request for a disallowance.

11.4 NUCLEAR LIABILITY DEFERRAL ACCOUNT

SEC (at argument para. 10.2.124) has invited OPG to show where the evidence satisfactorily explains the addition of $31.3M (the "Addition") to the balance of the Nuclear Liability Deferral Account as per the EB-2007-0905 Order and the opening balance shown in Ex. H1-T1-S1, Table 1a.

SEC argues that since there was no new ONFA Reference Plan in 2008, there should be no changes to the opening balance since the OEB's last order (SEC argument, para. 10.2.123). What SEC is missing is that difference between the nuclear liability costs that were in the rates approved by the Province for the period through March 31, 2008 and the actual nuclear liability costs pursuant to the 2006 ONFA Reference plan continues during first quarter of 2008. This difference is exactly what the Nuclear Liability Deferral Account is intended to capture.

At Note 7 to OPG's 2008 Audited Financial Statements (the "Audited Financial Statements"), there is a reference to the Nuclear Liabilities Deferral Account, including a description of the Addition (Ex. A2-T1-S1 Attachment 1, pp. 86-87). As per the Audited Financial Statements, during the year ended December 31, 2008, OPG recorded an increase to the Nuclear Liability Deferral Account of $37M, of which $6M is interest. As with the $130.5M addition to the Nuclear Liability Deferral Account (recorded during the year ended December 31, 2007), the Addition results from the increase in OPG's nuclear liabilities of $1,386M arising from the change in the ONFA Reference Plan at the end of 2006.

Further, the Addition is described at page 39 of OPG's Q1 2008 Financial Statements, which, while not part of the pre-filed evidence, are easily available to the public on OPG's website. The relevant portion of the Q1 2008 Financial Statements, dealing with the Nuclear Liability Deferral Account, reads as follows:

Nuclear Liabilities Deferral Account

In February 2007, the Province amended a regulation pursuant to the *Electricity Restructuring Act, 2004* (Ontario) that directed OPG to establish a deferral account in connection with certain changes to its liabilities for nuclear used fuel management and nuclear decommissioning and low and intermediate level waste management. The following items have been recorded as components of the deferral account:

(millions of dollars)	**March 31 2008**	**December 31 2007**
Return on rate base	**94**	75
Depreciation expense	**67**	54
Fuel expense	**(7)**	(5)
Capital tax	**4**	3
Interest expense	**6**	4
	164	131

With respect to the methodology for calculating the Addition, the same method used for the amount recorded in the December 31, 2007 year-end balance, which formed part of the OEB's approved balance in the last application, was used for the Addition (see EB-2007-0905, J1-T1-S1, Section 4.2).

OPG submits that the April 1, 2008 opening balance in the account is correct and that there should be no reduction in the amount available for clearance. OPG notes that had SEC sought further clarification of these amounts through interrogatories, the technical conference or cross examination, rather than raising the issue for the first time in argument, the need to address this matter might have been avoided.

VECC's and CME's submissions with respect to nuclear liability changes arising from the Darlington Refurbishment decision are addressed above in Section 9.0, Nuclear Waste and Decommissioning Liabilities.

11.5 NUCLEAR FUEL COST VARIANCE ACCOUNT

OPG proposes that this account be cleared as set out in its AIC at page 86. OPG also proposes that the account continue as it is currently structured. A number of parties have suggested that the account be restructured. OPG has replied to all of these submissions above in Section 4.4, Fuel Costs.

11.6 IESO NON-ENERGY CHARGES VARIANCE ACCOUNT

No parties have taken issue with OPG's proposed IESO Non-Energy Charges Variance Account except for SEC, and several parties have supported Board staff's submission that it would be reasonable for the OEB to approve this variance account (Board staff argument, p.95).

Board staff also recommended that OPG be required to demonstrate that it is making efforts to reduce consumption from the IESO grid in future applications (Board staff argument, p.95). OPG assumes that Board staff is referring to initiatives that are economic and practical. OPG is prepared to provide such evidence. OPG would also note that its evidence that the high energy consumption at Pickering is the direct result of a legacy wiring design from the time the plant was constructed. OPG explained this in greater detail at the Technical Conference (Technical Conference Transcript, pp. 12-13).

Oddly, Board staff also makes the submission that it would not be "unreasonable" to disallow the variance account because the variances over the 2008 to 2010 period don't seem to be material (Board staff argument, p. 95). This submission ignores OPG's evidence that it is expecting significant growth in the size of the Global Adjustment and as a consequence OPG's IESO Non-Energy charges as well as greater volatility in these amounts in the future (see OPG AIC, pp. 58-59). With respect to the question of materiality, OPG testified that it regards $10M over the test period as a material amount (Tr. Vol. 15, p. 46). Given the yearly variances experienced over the 2008-2009 period (Ex. H1-T3-S1), it is highly likely that the variances over the coming test period will significantly exceed this materiality threshold. Board staff acknowledges that its position on materiality is based on a straight line projection of past balances (Board staff argument, page 95). OPG's uncontroverted evidence establishes that these charges are expected to increase substantially and for this reason, Board staff's submission on materiality should be rejected.

SEC, in essence, appears to oppose the requested account on the basis that the IESO non-energy charges are a normal business risk. OPG disagrees. While these charges may have been part of normal business risks several years ago, and may again return to some level of predictability in the future, in more recent years and for the test period, owing to volatile components of these charges, most notably the Global Adjustment, these charges are well outside normal business risks. In fact, SEC itself acknowledges that, "These charges are material, and can cause dramatic increases or decreases in the delivered cost of electricity in Ontario" (SEC argument para.10.5.2). A variance account will protect both OPG and ratepayers from the over or under collection of these charges.

In OPG's submission, no purpose is served by attempting to classify the dramatic change in the nature of IESO non-energy charges as a normal business risk. For all of the reasons set out in OPG's AIC and testimony, this account should be approved (AIC pp. 58-59; Ex. H1-T3-S1, pp. 8-9; Tr. Vol. 1, pp. 94-109).

11.7 PENSION AND OTHER POST EMPLOYMENT BENEFITS COST VARIANCE ACCOUNT

OPG's reply submissions on this account are contained in Section 6.3, Pension and OPEB costs.

12.0 DESIGN OF PAYMENT AMOUNTS

Issue 9.1 - Is the design of regulated hydroelectric and nuclear payment amounts appropriate?

OPG is not seeking a change in the design of the payment amounts in this application. With the exception of the hydroelectric incentive mechanism (which is considered in Section 3.6), no intervenor objected to the proposed design of the payment amounts and riders. As such, and for all the reasons set out in its evidence and AIC, the design of the payment amounts and riders should be accepted by the OEB as filed.

13.0 REPORTING AND RECORD-KEEPING REQUIREMENTS

Issue 11.1 - What reporting and record keeping requirements should be established for OPG?

Board staff, supported by SEC, submits that OPG should begin filling certain documents for the 2010 fiscal year in 2011 (Board staff argument, pp. 102-103; SEC argument, paras. 11.1.1 - 11.1.7). OPG proposes that reporting and recording keeping requirements ("RRRs") should commence after a process (e.g., a workshop or other collaborative structure) to determine the specific information required to effectively monitor and regulate OPG, in light of the cost and time required to produce this information. Until such a process is complete, OPG does not support Board staff's current proposal.

Board staff's proposal stems, in part, from OPG's response to interrogatory L-01-149, where OPG indicates it <u>can</u> file certain information. However, Board staff provides no rationale for the information requested. While OPG does not object to the establishment of RRRs, it believes they should be tailored to OPG's regulatory environment and a potential future incentive regulation regime. Before issuing the RRRs for natural gas utilities, the OEB issued the paper "Rationales for the proposed Natural Gas Reporting and Record Keeping Requirements: An OEB Background Policy Paper." (April 15, 2004). OPG submits that similar thinking would be appropriate in its case. A separate process to establish RRRs for OPG would appropriately address the purpose of the RRRs and ensure the result is: effective - in providing the right information for monitoring; efficient - to minimize costs associated with reporting and monitoring; and minimally intrusive. Simply requiring OPG to file information contained in its publicly available annual and quarterly filings, as proposed by Board staff, does not meet these objectives.

Board staff includes capital in-service additions/ construction work in progress and actual annual regulatory return in its proposal for information to be filed. With respect to capital in-service additions and construction work in progress, the ability of OPG to file the information depends on the definition of the information to be filed, which Board staff acknowledges has yet to be determined. (Tr. Vol. 15, pp. 89-90). It is unreasonable to require OPG to file information for 2010 before defining the specifics of this reporting requirement. With respect to annual regulatory return, this was presented as a potential alternative to audited financial statements for the prescribed facilities, which OPG supported. However, specific requirements have not been defined for this document. Board staff states it would be *similar* to Ex. C1-T1-S1, Table 7, but any differences from that table should be determined before reporting is required.

Even more problematic is Board staff's proposal that OPG should prepare a report that details the internal costs to develop annual audited financial statements for the prescribed facilities. There is no evidence that these statements are of any utility, a fact reinforced by Mr. Barrett (Tr. Vol. 15, p. 91):

> I would also observe that as far as I can recollect, there has been no reference in this entire proceeding to those prescribed financial statements. So, again, that reinforces our own view that they did not provide much utility to this process.

In addition, Mr. Kogan indicated that it would be "a significant undertaking" for OPG to identify all of the systems that may need to be modified and implications for business processes (Tr. Vol. 15, p. 104). To require OPG to prepare a report detailing the costs to develop the capability to produce statements that are of no discernable value would clearly be a waste of resources.

Board staff has nowhere indicated why it believes these statements should be produced. Conversely, OPG has provided clear reasons why it believes these statement do not provide helpful information (L0-01-149). The vast majority of the financial statement information relevant to ratemaking can be found in the segmented information provided as part of OPG's consolidated financial statements.

Board staff's suggestion that other utilities, and specifically Hydro One, developed the capability of filing such reports misses the point of OPG's testimony (Tr. Vol. 15, p. 92). Hydro One, at its inception, designed its systems to allow it to create separate reports for its distribution and transmission businesses. OPG's systems were designed before identification of the prescribed facilities and regulation by the OEB. OPG's situation is not analogous to Hydro One's.

SEC submits that the fact that no-one referred to the prescribed facility statements throughout the proceeding is not an indication that they were of limited value (SEC argument, para. 11.1.6). While OPG cannot say with certainty how parties may or may not have used the prescribed facility statement, OPG's general observation is that documents that are important to the outcome of a hearing are typically discussed in the hearing. As a result, OPG maintains its position that there was no evidence of their value in the proceeding and that they should not be required.

14.0 METHODOLOGIES FOR SETTING PAYMENT AMOUNTS

Issue 12.1 - When would it be appropriate for the Board to establish incentive regulation, or other form of alternative rate regulation, for setting payment amounts?

Issue 12.2 - What processes should be adopted to establish the framework for incentive regulation, or other form of alternative rate regulation, that would be applied in a future test period?

Before addressing the submissions of parties, OPG believes that it is useful to reflect on the short history of OPG regulation.

During 2006, the OEB undertook a consultation to determine a methodology for regulating OPG's prescribed assets. On November 30, 2006, OEB issued a report entitled "A Regulatory Methodology for Setting Payment Amounts for the Prescribed

Generation Assets of Ontario Power Generation Inc." (EB-2006-0064 Board Report). At page 11 of that report, OEB found that it would "…undertake a series of limited issues cost of service processes to set the base payment. The Board will extend the limited cost of service process over several orders until all relevant issues have been examined. The Board will implement an incentive regulation formula when it is satisfied that the base payment provides a robust starting point for that formula." A subsequent filing guidelines report, issued by the OEB on November 27, 2009, maintained these findings.

In its evidence (Ex. L-01-150; Tr. Vol. 15, p. 106), OPG had proposed that it would file an application containing an IRM proposal by mid-2011. A short, focused hearing would follow allowing for an OEB decision in sufficient time for implementation issues to be considered as part of OPG's next payment amounts application that would be filed at the end of first quarter of 2012. The submissions from Board staff and intervenors are largely in response to this proposal from OPG.

Board staff submitted that the timeline suggested by OPG is aggressive and probably unrealistic, given that OPG is in the early stages of its planning (Board staff argument, p. 107). Board staff and CCC also express the view that the development of an incentive regulation mechanism is both time and resource intensive (Ibid., p. 107; CCC argument, para. 156).

Board staff is unaware of any IRM precedents that might form a starting point for OPG (Ibid., p. 108). They also suggest that it might make sense for there to be different IRM plans for the nuclear and hydroelectric assets (Ibid.). Board staff expects that developing an IRM for OPG would take longer than for other utilities and that there may well be matters carrying over from the current cost of service application that would first have to be dealt with (Ibid., p. 109).

One option identified by Board staff would be for OPG to file an application with both an IRM proposal and proposals for new rates effective January 1, 2013. They suggest that this application could be filed by the 3rd quarter of 2011 with the Board issuing separate decisions for each part of the application (Board staff argument, p. 109). They suggest that another option would be to allow OPG to apply for 2013 on a cost of service basis and then have OPG file a separate IRM application that would take effect for 2014. They acknowledge the downside of this proposal is that the applications would overlap (Board staff argument, p. 109). Finally, Board staff believes that OPG should consult extensively with stakeholders in the development of any IRM plan (Ibid, p. 110).

In contrast, CCC is not convinced that an IRM mechanism is appropriate for OPG given the unique issues faced by the company and given the fact that OPG's capital spending can be very lumpy (CCC argument, para. 157). They submit that IRM is better suited to utilities where a steady state level of spending is occurring (Ibid.). They see merit in incentives for some elements of OPG's revenue requirement but not all elements.

CCC also suggests a workshop to consider the threshold issue of whether or not IRM is appropriate for OPG before any further steps are taken (CCC argument, para. 158).

The PWU supports OPG's proposed IRM process (PWU argument, p. 92). They also submit that a proceeding is the preferred mechanism for establishing a regulatory framework for OPG rather than a settlement conference as this will ensure that OEB properly understands the new framework (Ibid.)

SEC expresses the view that OPG is not ready for any form of incentive regulation, and that most forms of IRM would not be suitable for OPG since these mechanisms are only suitable for stable businesses with relatively predictable needs (SEC argument, para. 12.1.5). They base this view on the fact that OPG is going through a big cultural change and that there will be significant changes in the nature and size of OPG's costs and rate base over the next few years (Ibid., para. 12.1.4).

Despite their view that OPG is not ready for IRM, SEC recommends that the process of developing IRM get started. They submit that the first step should be a proposal from OPG to be filed in the fall of 2011 (SEC argument, para. 12.2.5). They expect that the proceeding to consider this proposal would likely not be completed until the end of 2012 or the beginning of 2013 – this would allow OPG to remain under cost of service until the IRM mechanism could commence after 2014 (Ibid.)

OPG accepts the submissions from Board staff and others regarding the challenges of achieving OPG's proposed time table and even of crafting an IRM model for a business as complex as OPG's. However, both of Board staff's options for addressing these timing challenges are impractical and inconsistent with regulatory efficiency and thus should be rejected by the OEB.

- OPG bases its applications to the OEB on its most recently approved business plan. OPG's business planning process concludes with an approved business plan in December. This timing plus the need to incorporate year end accounting data, which is only available in mid to late February of the following year, means that the earliest OPG can file a complete application is the end of March.
- Board staff's first suggestion of a joint IRM/payment amounts filing in Q3 2011 is inefficient because it does not align with OPG's business planning cycle. A filing in Q3 2011 would have to be based on the OPG business plan approved in 2010, it would require, in essence, a complete updating of the numbers and information in the application in March of 2012 based on the business plan approved in Q4 2011 and the 2011 year end numbers. This would significantly increase the regulatory burden and costs for OPG, delay the progress of the hearing and restrict the value of the review undertaken by parties during the Q4 2011 and Q1 2012.

In addition, given that it takes about 6 months to prepare a payment amounts filing, OPG would have to begin intensive work on this application immediately after receiving the OEB's decision in this application in February of 2011. Preparing such an application, including responding to the directions from the decision and potentially undertaking new studies, would mean that OPG would not have the resources to properly consider IRM. Finally, OPG is not sure how Board staff's proposed two step decision process could be managed efficiently in one proceeding.

OPG also rejects Board staff other suggestion, what they call "a third option". Here, OPG would file a single year cost of service application for 2013 and then in parallel file an IRM application. In OPG's submission this model is unworkable. OPG does not have the regulatory and accounting staff resources to conduct two large proceedings in parallel and OPG suspects that intervenors don't either. Also, OPG does not support a one year cost of service application for its prescribed facilities given the amount of work effort and cost associated with preparing an application and conducting a proceeding. Finally, OPG cannot see how a one year test period would be in ratepayer's interests.

OPG notes the skepticism expressed by CCC and SEC about whether IRM for OPG is even advisable in the near term. OPG shares some of these concerns given the significant changes in store for its regulated business, including the Darlington Refurbishment project, the Continued Operations initiative, IFRS, the in-service of the Niagara Tunnel, and the need to consider whether OPG is recovering sufficient funds to cover the cost of its nuclear liabilities. However, OPG wants to be responsive to the OEB's directions on IRM.

As the current proceeding is only the second review of OPG's costs, OPG submits that a third cost of service review is necessary to address all relevant issues and ensure a robust starting point for IRM as originally envisioned by the OEB in its 2006 report. OPG notes that the Ontario gas utilities had decades of regulation by the OEB before they began the transition to IRM and they are less complex businesses than OPG.

OPG sees merit in the submissions on timing and required effort, and has developed two alternative approaches to address these concerns.

Under the first proposal, OPG would file its IRM proposal as part of its next rates application for 2013-2014. The 2013-2014 test period would be the base period for the IRM proposal and would be determined on a cost of service basis. If an IRM proposal is adopted, it could take effect beginning on January 1, 2015.

This application would be filed by the end of Q1, 2012, allowing OPG sufficient time to develop a proposal and to discuss it with stakeholders. This timing would also allow OPG to use its 2011 business plan and 2011 year end data in the next application.

Alternatively, if OEB was inclined to give greater weight to the submissions of CCC and SEC on the need to have stability in the business operations of OPG before embarking on IRM, IRM could be considered after the next cost of service review for 2013-2014. Under this alternative timeline, OPG would file an IRM proposal in 2013, after the conclusion of the next hearing. The expectation is that there would be greater stability in

OPG's operations by then and a longer track record of regulation, two things that would assist in the development of an effective IRM.

15.0 IMPLEMENTATION

In its Argument-in-Chief, OPG sets out its request for implementation of new payment amounts and riders effective March 1, 2011 and its request that current payment amounts be declared interim effective March 1, 2001 if the order or orders approving new payment amounts are not implemented by March 1, 2011 (OPG AIC, p. 98; Ex. A1-T2-S2, p. 3). No party has objected to OPG's request and as such, OPG submits that its request should be approved.