EB-2013-0321

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an Application by Ontario Power Generation pursuant to the *Ontario Energy Board Act* for an Order or Orders approving payment amounts for the years 2014 and 2015

FINAL ARGUMENT
OF THE
SCHOOL ENERGY COALITION

August 26, 2014

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0 GENERAL COMMENTS

0.1 *Introduction*

0.1.1 On September 27, 2013 the Applicant Ontario Power Generation filed an Application to set payment amounts for its existing prescribed facilities for the period commencing January 1, 2014, and for its newly regulated hydroelectric facilities for the period commencing July 1, 2014, based on its revenue requirements for the years 2014 and 2015. The Application seeks increases of $2.1597 billion in its hydroelectric and nuclear revenues, based on revenue requirement for the Test Period of $1.7578 billion for its previously hydroelectric prescribed facilities, $0.8532 billion for its newly regulated hydroelectric facilities, and $6.3954 billion for its nuclear prescribed facilities[1].

0.1.2 With a total proposed revenues of just over $9 billion, this Application constitutes the biggest request for regulatory funding approval in the Board's history, and the increase is the biggest increase in rates ever requested from the Board[2].

0.1.3 After a lengthy hearing process, including the filing of late-breaking evidence that changed the nature of the discussion with respect to the Darlington Refurbishment Project, the Applicant filed its Argument in Chief on July 28, 2014. Board Staff subsequently filed its Final Argument on August 19, 2014. This is the Final Argument of the School Energy Coalition.

0.1.4 The ratepayer groups who intervened in this proceeding have worked together throughout the hearing to avoid duplication, in some cases also exchanging partial drafts of their final arguments. We have been assisted in preparing this Final Argument by that co-operation amongst parties. We especially note the very helpful co-operation of AMPCO, CME and VECC in this process. Where we are in agreement with the submissions of other parties, we have not repeated their arguments here, but have adopted their reasoning to the extent possible.

0.1.5 We also note that the thorough and careful Final Argument prepared by Board Staff was particularly valuable in this proceeding. In many cases, we agree with their conclusions, and where we have we have so stated in the body of these submissions. We understand that other parties are doing so as well. Even where we do not agree, their extensive and thoughtful analysis has been extremely useful.

0.1.6 The complexity of this proceeding necessarily required prioritization by intervenors. As a result, we have not made submissions on every issue on the Issues List. In a number of cases, we have elected to focus our resources on other areas, and not develop positions on issues, including some that have material

[1] K3.5, p. 2.
[2] Tr. 3:6-7.

impacts. Where SEC indicates that it does not have submissions on any issue, that should not be interpreted as agreement with the Application or any aspect of it, nor agreement with the position of any other party to this proceeding. Where we agree, we say so explicitly. Silence is just silence.

0.1.7 Except for this first Section, and Section 13, the numbering of Sections and Subsections in this Final Argument is consistent with the numbering OF the Board-approved Issues List.

0.2 ***Summary of Submissions***

0.2.1 This Final Argument contains a detailed analysis of some of the issues arising in this proceeding. The following are some of the main recommendations resulting from that analysis.

0.2.2 ***Equity Thickness and ROE.*** SEC proposes an equity thickness of 42.34%, subject to adjustment depending on the final rate base approved by the Board. Our calculation[3] follows the same approach as the Board used in EB-2007-0905, i.e. the weighted composition of the Applicant's rate base relative to risk.

0.2.3 ***Hydroelectric Rate Base***. SEC has reviewed the Applicant's forecast vs. actual capital additions in hydroelectric, which shows that actual is 83.3% of plan. Based on this history, SEC proposed that hydroelectric capital additions be reduced by $14.0 million in 2014, and $25.3 million in 2015.

0.2.4 ***Niagara Tunnel.*** In Section 4.4 of this Final Argument, SEC provides a detailed analysis of the problems with the Niagara Tunnel project, and the cost overruns that resulted. Our conclusion is that 50% of the cost overrun should be included in rate base, and the other 50% disallowed as imprudent. This would have the effect of reducing opening rate base by $245.7 million.

0.2.5 SEC is also proposing to adjust the useful life of the Niagara Tunnel from 120 years to 150 years to reflect the fact that the Niagara Tunnel uses more modern materials, and should last longer than the 120 years for the two existing tunnels.

0.2.6 ***Nuclear Rate Base***. SEC proposes two adjustments to nuclear capital additions.

0.2.7 First, we agree with Board Staff that the in-service additions for nuclear other than Darlington should be reduced by $18 million in 2014, and $17 million in 2015.

0.2.8 Second, SEC proposes in-service additions for the Darlington Refurbishment projects of $34.6 million in 2014 (an increase of $15.9 million) and $6.6 million in 2015 (a decrease of $202.8 million). This represents the two projects for which the

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[3] See para. 3.1.37.

Applicant has provided the Board with appropriate supporting evidence, and which will be used or useful in the Test Period.

0.2.9 ***OM&A.*** SEC proposes reductions in Hydroelectric OM&A of $9.7 million in 2014, and $10.0 million in 2015, based on OPG's history of over-forecasting these costs. This is in addition to the impact of compensation and pension/OPEB adjustments. With respect to Nuclear OM&A, our proposed reductions are entirely subsumed within our compensation and pension/OPEB components.

0.2.10 SEC also proposes that the Applicant's central support and administrative OM&A be reduced by $35 million in each of 2014 and 2015. This represents problems with overstaffing and flawed benchmarking in this area.

0.2.11 ***Compensation Costs***. SEC proposes two adjustments to the compensation costs (excluding pension/OPEBs).

0.2.12 First, SEC submits that the Board – having provided the Applicant with ample warning over the last several years – should now only allow the Applicant to collect in rates PWU compensation costs at the 50th percentile. This would reduce compensation by $96 million in 2014, and $94 million in 2015.

0.2.13 Second, SEC proposes a further disallowance of $4 million in 2014, and $6 million in 2015, to recognize the well-known problems OPG has shown with respect to oversight of their actual compensation costs, such as incentive levels, overtime, performance monitoring, etc.

0.2.14 SEC is not proposing an additional compensation adjustment to reflect the Applicant's failure to control their management FTEs.

0.2.15 ***Pension/OPEBs.*** This Final Argument recognizes the serious problems OPG shares with other successors to Ontario Hydro in their pension and other post-employment benefit costs. However, we also recognize that the government has initiated a process to address those problems on a generic basis.

0.2.16 While that process is going on, SEC proposes that the Board change the rate recovery method for these costs to the more common cash method, from the existing accrual method. In the past, the two amounts were not significantly different over time. Starting in 2013, it appears that for the foreseeable future cash will be significantly lower than accrual. The impact of moving to the cash method is a reduction in revenue requirement of $352.4 million in 2014, and $256.9 million in 2015.

0.2.17 ***Income Tax.*** SEC agrees with Board Staff that the tax loss carry-forward from 2013 should be applied in 2014 to reduce Test Period taxes by $52.9 million, and revenue requirement by $70.5 million.

0.2.18 SEC also proposes that the Board make clear that tax and pension costs actually incurred by OPG prior to 2014 with respect to the Newly Regulated Hydroelectric facilities cannot be recovered in regulated rates going forward, as that would be retroactive ratemaking.

0.2.19 ***Nuclear Other Revenues***. SEC supports the submissions of AMPCO that the revenues from Heavy Water Sales should be increased by $59.5 million over the Test Period.

0.2.20 ***Nuclear Liabilities***. We agree with AMPCO that the expense associated with decommissioning should be reduced by $14.1 million in 2014, and $14.4 million in 2015.

0.2.21 ***Darlington Refurbishment.*** SEC does not believe that the Board should provide any approval or endorsement of either the $1.7 billion of Darlington capital expenditures in the Test Period, or the commercial and contracting strategies used, or being proposed by the Applicant, for the Darlington Refurbishment project.

0.2.22 ***SBG/HIM***. SEC supports the proposals of Board Staff on these issues.

0.2.23 ***Nuclear Production Forecast.*** SEC agrees with the adjustments proposed by Board Staff.

0.2.24 ***Other Deferral and Variance Accounts.*** SEC proposes addition of a Bruce Lease USGAAP Variance Account, to record the $59 million retroactive adjustment of lease revenues. SEC also supports the establishment of the GRC Variance Account with respect to likely 10 year GRC holiday for the Niagara Tunnel, as proposed by Board Staff.

0.2.25 ***Implementation and Effective Date.*** SEC supports establishment of rates for the Newly Regulated Hydroelectric facilities as of July 1, 2014, on a cost of service basis, and without mitigation. However, with respect to the remaining Prescribed Facilities, we believe that the effective date should be the first day of the month following the Board's payment amounts order.

1 GENERAL

1.1 *Board Directions*

1.1.1 The EB-2007-0905 and EB-2010-0008 decisions set out a number of directions from the Board for actions that the Applicant should take in this Application. Where those directions are relevant to our comments on the issues set out in this Final Argument, we have commented on them there.

1.1.2 With respect to any Board directions on which we have not provided comments elsewhere in this Final Argument, we have no additional submissions.

1.2 *Economic and Business Planning Assumptions & "Business Transformation"*

1.2.1 ***Economic Assumptions.*** Our submissions with respect to economic assumptions are included in the subject matter areas to which they relate. We have no additional submissions.

1.2.2 ***Business Planning Assumptions.*** Much of this Application, and hence this Final Argument, is about business planning assumptions. For the most part, our submissions on those assumptions are included in the specific subject areas.

1.2.3 There are two categories of business planning assumptions on which we make general submissions. First, we deal with the approach of the Applicant to its unions, and how that approach affects business planning. Second, as the Applicant did in their Argument in Chief[4], we will make our general submissions on the Business Transformation initiative in this section.

1.2.4 ***Union Negotiations.*** SEC accepts that there is a collective bargaining reality that OPG faces in its efforts to control costs. SEC also agrees with Board Staff[5] that the Board's role is not to supervise, or even critique, OPG's handling of its unions. The Board's role is to ensure that only a reasonable cost of labour is included in rates.

1.2.5 Despite those realities, SEC believes the Board should be concerned with the relentlessly "defeatist" attitude that OPG expresses with respect to its dealings with its unions[6]. If OPG does not adopt a more constructive and positive approach to collective bargaining, it is difficult to see how they will be able to control costs in fact. If that is the result, then either they will make less money, hurting their long

[4] AIC, p. 6-8.
[5] Staff Submissions, p. 76-78.
[6] See for example, Tr. 8:2,159,170-171.

term financial condition[7], or they will collect too much from ratepayers, hurting the ratepayers' financial condition.

1.2.6 This does not mean that the Board should require the Applicant to "get tough" with PWU and the Society, nor indeed to stipulate any particular change to their negotiating strategies and targets. The Board is not expert in labour relations, and should not be giving OPG labour relations advice or directions.

1.2.7 It does mean that the Board can and should be justifiably critical of management of Ontario's largest utility simply "giving up" when it comes to negotiations. It is not acceptable, in our view, for OPG to say that there is no point in gathering benchmarking information, because the unions won't care[8]. It is not acceptable, in our view, for OPG to say that essential reforms to the pension plan are not going to happen because "we can't achieve them", or words to that effect[9].

1.2.8 In their submissions, Board Staff note that "Companies operating in a market environment must rigorously control their costs or run the risk of bankruptcy.[10]" SEC would add to that a corollary: if they can't control their costs due to union resistance, the market doesn't care; they still go bankrupt.

1.2.9 Just because OPG is regulated, doesn't mean that OPG management can throw up their hands and say it is easier to get more money from the ratepayers than to get needed changes from the unions. If that's true, then the Board would not be operating properly as a market proxy. The market doesn't accept excuses; neither should the Board.

1.2.10 We note that there is another side to this management attitude. By assuming that the unions will not agree to things that really need to happen, management must be assuming that the unions will be unreasonable. It is not clear to SEC that this is an immutable truth. Are unions sometimes unreasonable? Certainly, management of companies are sometimes unreasonable, as well. But unions also have smart people, able to understand realities, and work constructively to find solutions to problems. Not all unionized companies go bankrupt. Some are quite healthy.

1.2.11 SEC therefore submits that the Board, in its decision, should deal with this "defeatist" approach to the Applicant's unions directly. The Board should, in our submission, require OPG, in their next payment amounts proceeding,

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[7] And potentially that of their shareholder.
[8] Tr. 8:170-171
[9] Tr. 8:2. Tr. 8:159
[10] Staff Submissions, p. 78.

(a) to provide comprehensive evidence that they are making material progress in solving the problems that need the co-operation of their unions; and

(b) to demonstrate that they no longer have a "can't do" view of matters affecting unionized employees.

1.2.12 ***Business Transformation Initiative.*** After much criticism, from number of sources, OPG embarked on the Business Transformation initiative, designed to change OPG into a company that is able to withstand its inevitable decline in generation assets. This goal was described as follows:[11]

> *"Business Transformation is intended to transform OPG so that it can compete, grow and respond to changing market conditions without compromising continued safe and reliable operations.*
>
> - *Reducing staff levels by 2,000 employees by the end of 2015. This reduction aligns with expected attrition that is factored into business plan assumptions, and better aligns OPG's staff levels with production and revenue expectations.*
>
> - *Creating a scalable organization, which is more efficient and effective. This will give OPG flexibility to scale up or down areas of the organization based on changing needs to support various operational units.*
>
> - *Moving to a centre-led organizational model that allows best practices to be better shared and integrated across the company"*

1.2.13 The Business Transformation initiative sounds good, but when it is looked at more closely, a number of questions emerge.

1.2.14 First, it is not clear why it suddenly occurred to OPG now that it is better to have, for example, one public relations department rather than several[12]. This concept seems rather obvious, and is certainly common practice for many larger companies that have multiple business units. In fact, the concept of Shared Services is used by most of the other large utilities regulated by the Board, including Enbridge, Hydro One, Toronto Hydro, Horizon, and many others. The avoidance of duplication is a pretty basic management goal in large organizations.

1.2.15 Second, the one circumstance in which a company might be <u>least</u> likely to use the centralized functions model would perhaps be where the company has a declining business base. If personnel or other resources are attached to an operating unit that

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[11] A4/1/1, p.2.
[12] A4/1/1, p.3.

is being phased out (a nuclear unit at the end of life, perhaps), it is not surprising that those resources become redundant. If, on the other hand, personnel providing services to the operating unit being phased out are actually part of a central services unit, their jobs would appear to be more secure. At the very least, their argument (or the argument of the union) for retaining those centralized personnel is a different, and likely stronger, one.

1.2.16 Third, the overall purpose of a transformation initiative such as this is usually to improve efficiency, <u>and therefore reduce costs.</u> One could argue that efficiency is being improved by the Business Transformation initiative, because total FTEs are down, so far, by 8.38%, or 878.3 FTEs, as a result of this initiative[13]. However, when costs are going up, over the same period, by 9.04%[14], <u>before</u> taking into account the large increases in the accrual portion of pension and OPEBs costs, the initiative doesn't appear to be accomplishing the entire intended result.

1.2.17 OPG in fact admits essentially that, in the following exchange[15]:

> *"MR. SHEPHERD: So despite the absolute reductions in the numbers of people, the net effect of business transformation is not to have an absolute reduction in costs; it is to have your cost increases reduced?*
> *MR. BARRETT: I wouldn't describe it quite that way, but the result is that there is -- it still remains, even after all of the savings achieved through BT, some cost pressures which are not mitigated. So the net overall effect is that costs have gone up."*

1.2.18 Fourth, as we note in our analysis of compensation costs later[16], while 80% of employees prior to Business Transformation were in the regulated part of the business, only 65% of the reductions in FTEs are in regulated. It appears that part of the reason for the FTE success to date is the phase-out of the coal plants, not the Business Transformation initiative at all.

1.2.19 Fifth, while the target FTE reduction is 2,000, the current forecast is a total reduction of 1,085.1 for the five years ended 2015. That is in the context of compensation costs for each FTE, again excluding pension and OPEB accruals, increasing by 14.16%.

1.2.20 Sixth, the FTE reductions appears to be almost entirely within the unionized employees, who are getting pay raises instead. Although management staff represent 10.51% of employees in 2010, the reductions in FTEs in that category are 2.34% of the total reductions[17]. Given that there was already a concern with the

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[13] J9.7, line 33.
[14] J9.7, line 35.
[15] Tr. 11:124
[16] Para. 6.8.3.
[17] J9.7, line 36.

top-heavy management structure of OPG[18], this suggests that the Business Transformation initiative, even if good in concept, is seriously deficient in implementation. The fact that, despite this initiative, OPG is asking for more than $2 billion of <u>additional</u> money is fairly clear proof of that.

1.2.21 It may seem like caviling to criticize a company that is apparently trying to respond to criticism with a major plan to fix their problems. The alternative, however, is to look at an initiative with obvious flaws and say everything is OK. It's not, and in our submission part of the role of the Board is to point out those flaws, and invite OPG to correct them before OPG comes back in later for more money.

1.3 ***<u>Application of USGAAP</u>***

1.3.1 Two issues have been raised during the proceeding with respect to the implementation of USGAAP, and its impacts.

1.3.2 ***Bruce Lease Net Revenues.*** Under Canadian GAAP, the net revenues from the Bruce Lease that are credited to the ratepayers are amortized on a straight line basis commencing at the time of regulation, April 1, 2008. Under US GAAP, the net revenues are amortized on a straight line basis commencing at the beginning of the lease. The difference as of January 11, 2011, when US GAAP was adopted, was a $59 million reduction in the total credits available to ratepayers. Those credits are reduced, relative to CGAAP, by a net (after tax impacts) of $1.6 million per year[19].

1.3.3 The effect of the change is - retroactively - to characterize $59 million of Bruce Lease credits as arising prior to regulation, rather than in the period the prescribed assets have been regulated, as was the case since 2008. OPG proposes to treat that $59 million as part of retained earnings.

1.3.4 SEC submits that the $59 million adjustment should not be permitted. The effect would be to allow an external accounting change to reallocate $59 million from the ratepayers to the company, despite no actual change in circumstances.

1.3.5 Instead, SEC submits that the Board should order that the $59 million be credited to a deferral account, to be drawn down at the appropriate rate each year, thus ensuring that the ratepayers get the annual Bruce Lease credit that was originally intended.

1.3.6 ***Pension and OPEBs.*** The Applicant has purported to support their proposed calculation of pension and OPEB costs by reference to the requirements of US

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[18] See for example, *Report of the Auditor General - Chapter – Ontario Power Generation Human Resources* ("Auditor General Report"), KT2.4, p. 159
[19] The full explanation is in .L/1.3/17-SEC-19.

GAAP[20]. SEC will deal with that part of the analysis in its submissions on pension and OPEB costs, in Section 6.8 below.

1.3.7 ***Unapproved Accounting Changes.*** The Applicant has from time to time revised their accounting policies, including depreciation rates, so that they are different from the basis on which rates were set. In some cases, that has resulted in their operating costs, for accounting purposes, being reduced after the fact, while rate base or other balance sheet items are adjusted accordingly.

1.3.8 SEC has had an opportunity to review the submissions of Board Staff on this issue[21]. We agree with both their analysis, and their conclusion.

1.3.9 In general, SEC believes that if rates are set on a cost of service basis, and there are material accounting assumptions built into the costs on which the Board relies in setting those rates, utilities should not be allowed to change those accounting assumptions, for regulatory purposes, without the approval of the Board. By seeking Board approval, OPG would be giving the Board the opportunity to determine if any other adjustments are required as a result of the accounting change requested.

1.3.10 We note that Staff have proposed that there be a materiality limit for this requirement. On this point, SEC does not agree. If a change is not material, then OPG is put to their election. They can make the change for financial accounting, but without any regulatory effect, or they can still seek Board approval and, if approved, make the change for both purposes. If OPG is proposing to make a change that will be applicable for three years before rates are changed, but with only a $10 million annual cost, OPG may well determine that it is better to seek regulatory approval. An application with a $30 million impact would still be larger than most applications that utilities make to the Board each year.

1.4 ***Overall Increase in 2014 and 2015 Revenue Requirement***

1.4.1 ***Increased Revenue Requirement.*** The Applicant is seeking an increase in revenue requirement of about $2.1597 billion[22], which is 31.5% higher than existing revenues[23]. The move from $6.8 billion to $9.0 billion in revenues over two years comes in the face of the Applicant's evidence that it is taking significant steps to control costs.

1.4.2 The evidence shows, however, that much of the increase is arising from a small number of identifiable reasons: pension/OPEBs, the Niagara Tunnel rate base,

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[20] AIC, pp. 3-5.
[21] Staff Submissions, p.3-5.
[22] K3.5, p.2. Tr. 3:31
[23] K3.5, p.2. Tr. 3:31

Bruce Lease net revenues, OM&A increases (particularly compensation), and cost of capital (plus tax impacts)[24]. In addition, the deficiency is increased substantially by the jump for the Newly Regulated Hydroelectric from HOEP to cost of service. This is not primarily an increase in costs, but rather covering a pre-existing and recurring operating loss.

1.4.3 What is clear is that one of the biggest drivers of this increase is pension and OPEB costs and related tax impacts[25]. We deal with that problem in the second part of Section 6.8 of this Final Argument.

1.4.4 Of considerable importance is the context of this increase. OPG is quick to point out that they produce relatively low cost electricity for the benefit of Ontarians[26]. This is undoubtedly true. However, that fails to take account of two key facts:

(a) When OPG was created, at least $20 billion of its debt was off-loaded to Ontario Electricity Financial Corporation, because the government of the day correctly realized that OPG was not sustainable if it had to service all of its debt. The restructuring of the former Ontario Hydro was, in effect, a form of bankruptcy proceeding, in which an insolvent company was allowed to continue in operation without having responsibility to pay all of its debts. If OPG had to carry all of its debt, its costs would be considerably higher.

(b) OPG started its existence with some of the premier hydroelectric generation assets in the world, and while their book value was bumped up by $5 billion in 1999 when OPG was formed[27], the resulting value was still much lower than current capital costs for similar assets. Generating power at a reasonable cost on the initial foundation of such valuable assets is less of an achievement. Producing inexpensive power is simply easier when you start with the single most powerful waterfall in North America, one of the most powerful in the world.

1.4.5 SEC has concern when OPG seeks to justify its costs by reference to their overall price vs. wind and solar power. This is especially true since the Global Adjustment was originally intended to return to ratepayers some of the benefit from these low cost assets[28]. It was not supposed to turn into a multi-billion dollar annual subsidy

[24] J3.3. See also our discussion of this in the oral hearing, at Tr. 3:31-37
[25] The amount by which USGAAP accrual-based pension and OPEB costs exceed the amount deductible for tax purposes (essentially, the cash-based pension costs) is treated under the Income Tax Act as if it were profit. From a taxable income point of view, it is revenues received from the customers, that are not actually spent on anything, and therefore are taxable. The grossed-up tax on that excess causes an additional, material increase in the requested revenue requirement.
[26] AIC, p.10.
[27] Tr. 12:130
[28] Low cost either because of their intrinsic value relative to cost, like Sir Adam Beck, or because the higher actual costs were effectively subsidized by the shifting of debt to the OEFC.

of OPG.

1.4.6 SEC urges the Board to consider, as a factor in making its decision, the failure by OPG to deliver on the low-cost promise of its assets, allowing the annual cost of those assets, instead, to increase, eating into the implicit ratepayer benefit they started with.

1.4.7 ***Increase in Payment Amounts***. The Applicant says that the proposed increase in the Payment Amounts is 23.4%[29]. By itself, that is just a number.

1.4.8 For schools, however, that is dollars. Schools will consume approximately 4.0 Twh in the two year test period. Although schools generally procure their electricity at market rates, through the Global Adjustment they still bear the OPG cost rate for about half of their electricity. In real terms, that means that OPG is asking schools to pay $27 million more for their electricity in 2014 and 2015[30]. Further, the majority of those cost increases carry on into the future, meaning an additional $10-15 million each year in payments to subsidize OPG, year after year.

1.4.9 We single out schools only because we are SEC. The same is just as true of all other customer groups. Businesses will be affected; jobs will be lost; economic activity will be dampened.

1.4.10 OPG talks about the extra cost being only $63 per residential customer[31], but doesn't comment on the impact on other customers. In fact, in their Argument in Chief they downplay the increase, focusing on their cost-cutting attempts[32], and claiming that the increases are not their fault.

1.4.11 It is, in our submission, shocking that the Applicant would ask for a 23.4% increase, deal with the reasonableness of that increase by saying they are trying to cut costs, and then deny responsibility for the $9 billion revenue requirement they are seeking. Where does the buck stop, if it doesn't stop with the OPG management?

1.4.12 You can't ask customers to pay an additional amount every year of more than a billion dollars, and not have consequences. In our submission, the only line of defence for customers against those significant consequences is the Board. The Board should be demanding of OPG that it

(a) control its costs, and

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[29] Tr. 3:133.
[30] That is, about $115 million for the OPG component, vs. $88 million at current rates.
[31] N2-1-1, p.12. $5.31 per month for a typical residential consumer x 12 months = $63.75
[32] AIC, p. 10.

(b) stop coming back to the Board, time after time, asking for more money while three quarters of its many, many employees remain on the sunshine list[33].

1.4.13 ***Cryin' The Blues.*** SEC cannot leave this issue without dealing with the Applicant's claim, repeated many times, and again in the Argument-in-Chief, that[34]:

"OPG has not had an increase in its base payment amounts since April 1, 2008, [so] the need for the proposed increase becomes even more apparent."

1.4.14 SEC decided to test this by looking at the actual payment amounts, each year since the Board started to regulate OPG. The resulting table – which compares actual revenues at approved rates to revenues at 2007 rates - shows a somewhat different picture[35]:

[33] In 2013, OPG paid its 526 employees making over $200,000 a total of more than $131 million, not including pension, OPEB and other compensation costs excluded from the T4s of employees. OPG have more employees over $200,000 than all of the other electricity companies and agencies reporting on the sunshine list, combined. They also have more employees on the overall sunshine list than all of the other electricity companies, and agencies, combined. See KT2.3.
[34] AIC, p. 3.
[35] We note that the basic statement of fact is technically correct. The Board has set base payment amounts twice so far. Once was the large increase on April 1, 2008. The second time was a small decrease effective January 1, 2011. If you ignore the rate riders ($923 million from 2008-2013), OPG has certainly only had one increase in its two rate cases, and that was in the first one.

We Never Get Any More Money

Year	Previously Regulated Hydroelectric						
	Payment Amount	Riders	Total Payment Amount	Production (Twh.)	Revenue ($millions)	Base Revenue	Increase over 2007
2007	$33.00	$0.00	$33.00				
2008	$36.66	$0.00	$36.66	19.0	$696.5	$627.0	$69.5
2009	$36.66	$0.00	$36.66	19.4	$711.2	$640.2	$71.0
2010	$36.66	$0.00	$36.66	18.9	$692.9	$623.7	$69.2
2011	$35.78	-$1.65	$34.13	19.5	$665.5	$643.5	$22.0
2012	$35.78	-$1.65	$34.13	18.5	$631.4	$610.5	$20.9
2013	$35.78	$2.53	$38.31	18.9	$724.1	$623.7	$100.4
Sub.					$4,121.6	$3,768.6	$353.0
2014	$42.75	$2.53	$45.28	20.1	$910.1	$663.3	$246.8
2015	$42.75	$3.36	$46.11	21.0	$968.3	$693.0	$275.3
Totals					$6,000.1	$5,124.9	$875.2

Year	Nuclear						
	Payment Amount	Riders	Total Payment Amount	Production (Twh.)	Revenue ($millions)	Base Revenue	Increase over 2007
2007	$49.50	$0.00	$49.50				
2008	$52.98	$2.00	$54.98	48.2	$2,650.0	$2,385.9	$264.1
2009	$52.98	$2.00	$54.98	46.8	$2,573.1	$2,316.6	$256.5
2010	$52.98	$2.00	$54.98	45.8	$2,518.1	$2,267.1	$251.0
2011	$51.52	$4.33	$55.85	48.6	$2,714.3	$2,405.7	$308.6
2012	$51.52	$4.33	$55.85	49.0	$2,736.7	$2,425.5	$311.2
2013	$51.52	$5.23	$56.75	44.7	$2,536.7	$2,212.7	$324.1
Sub.					$15,728.9	$14,013.5	$1,715.4
2014	$67.60	$5.23	$72.83	48.5	$3,532.3	$2,400.8	$1,131.5
2015	$67.60	$1.35	$68.95	46.1	$3,178.6	$2,282.0	$896.6
Totals					$22,439.7	$18,696.2	$3,743.6

1.4.15 The above figures are directly from the relevant payment orders, except for the 2014 and 2015 amounts, and have in each case been verified in the subsequent rate order comparisons. All production figures are actuals, either from this proceeding, or from EB-2010-0008. The riders exclude riders for revenue shortfalls, as those would not be incremental.

1.4.16 The first and obvious question is: What about inflation? The answer is that if their 2007 rates had been inflated annually, without any productivity assumption whatsoever, the 2013 rates would still be lower by 2% for hydroelectric, and 5% for nuclear.

1.4.17 The next question is: Isn't the 2008 jump simply to get to a fair level? The answer should be yes. However, the Board now knows that OPG has had excessive cost levels for many years, and this is now the third Payment Amounts proceeding in which those cost control issues have been front and centre.

1.4.18 What OPG should be demonstrating, by now, is declining costs. Instead, in this Application they are asking that the $2.1 billion extra the Board has already allowed them to collect from ratepayers, up to the end of 2013, be increased to $4.6 billion for the full eight years of regulation 2008 through 2015. This is about 20% more than revenue at 2007 rates. No cost control apparent there.

1.4.19 Another way to look at this is that the proposed payment amounts for 2014/15 from Previously Regulated Hydroelectric are 39% higher than 2007, but they are also 25% higher than 2008, when rates had already been increased by the Board. The proposed payment amounts for Nuclear are more than 43% above 2007, but they are also 29% higher than 2008. These are not defensible results.

1.4.20 This is against a backdrop of an asset base that was handed to the company, with a bump in values, and reduced debt, and represents assets that are depreciating over time. For assets such as these, the annual cost to produce the same amount of generation should be going down over time, as the rate base and therefore cost of capital goes down. Instead, OPG proposes to collect an average of 28.3% more ($950 million per year) in 2014 and 2015 than they did in 2008 (when the Board had already given them rate increases) for roughly the same production. This is a compound annual increase of more than 4% per year, for assets where costs should be declining.

1.4.21 This is also against a backdrop of declining interest and tax rates that should reduce the costs of a capital-intensive business.

1.4.22 SEC submits that the Applicant's claim that it never gets any rate increases, so now it should get one, is ill-founded and is not an appropriate argument from a company with a bloated cost structure, and costs that should be declining even without action.

2 RATE BASE

2.1 ***Overall Amount of Rate Base***

2.1.1 Our submissions relating to rate base issues are included under the Section 4 issues.

3 CAPITAL STRUCTURE AND COST OF CAPITAL

3.1 *Equity Thickness and ROE*

3.1.1 The Applicant has added almost $4.0 billion of lower risk rate base to its overall assets, but proposes to retain the 47% equity ratio approved in EB-2010-0008[36]. SEC believes that, because the Applicant's business risk has clearly changed, its equity ratio should be reduced.

3.1.2 SEC has had the advantage of reviewing a draft of the submissions of VECC on this issue, and in general we agree with their analysis, and directionally with their conclusions. However, we reach a similar result with a slightly different analysis.

3.1.3 The Applicant relies heavily on the evidence of Ms. Kathleen McShane, an expert on cost of capital who is well known to the Board. Ms. McShane was also a witness for OPG in the EB-2007-0905 and EB-2010-0008. Her evidence was rejected by the Board in both of those proceedings, in each case because her proposed equity thickness was much higher than the Board thought was reasonable[37].

3.1.4 Ms. McShane's evidence in this proceeding raises the following five questions for the Board to answer in setting equity thickness:

(a) What is the business risk of the Newly Regulated Hydroelectric, and the Niagara Tunnel, relative to either the Previously Regulated Hydroelectric, or Nuclear?

(b) How, if at all, should the risk associated with the Darlington Refurbishment be taken into account in establishing equity thickness?

(c) How, if at all, should the potential change in business risk that may arise when the refurbished Darlington is brought into service, and other nuclear stations are decommissioned, be taken into account by the Board in setting the equity thickness in this proceeding?

(d) How, if at all, should the future expectation of IRM be factored into any discussion of equity thickness?

(e) If the business risk has changed in a material way, what is the appropriate methodology to adjust the equity thickness to reflect that change in business risk?

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[36] AIC, p.12.
[37] EB-2007-0905 Decision p. 141-143. EB-2010-0008 Decision, p. 117.

3.1.5 It should be noted that we have not included in these questions the opinion/conclusion of Ms. McShane with respect to the appropriate equity thickness today. The Board's policy is clear. Equity thickness should change, and only change, when business risk changes. Ms. McShane's expert opinion – i.e. that the equity thickness should remain at 47% because it was too low before[38] – is not useful to the Board. She has a view that OPG should have more equity. The Board does not agree[39].

3.1.6 Therefore, in our view her evidence is only useful to the extent that it analyses the changes in business risk, and their potential impact on the equity thickness. Her final number includes her bias in favour of a higher number, and so is not something on which the Board can rely.

3.1.7 ***Business Risk of Newly-Regulated Hydroelectric and Niagara Tunnel.*** Ms. McShane provided her opinion that the business risk of the Newly-Regulated Hydroelectric facilities, and the Niagara Tunnel, is greater than the Previously Regulated Hydroelectric, but less than Nuclear[40].

3.1.8 SEC asked Ms. McShane about the basis of her opinion, and her expertise in the area. After an extensive discussion[41], it became clear that Ms. McShane has no independent knowledge of the business risks of the Newly Regulated Hydroelectric, or the Niagara Tunnel, and has no expertise in the field. She relied entirely on an assessment given to her by unnamed people at OPG. Those people did not provide evidence in this proceeding.

3.1.9 Her opinion was based on the following "facts", none of which she was able to verify independently, and most of which are probably untrue:

(a) The Newly Regulated Facilities are largely peaking units[42].

(b) Smaller facilities are more likely to be peaking facilities[43].

(c) They are on a "large number of river systems"[44].

(d) They are generally small facilities[45].

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[38] Tr. 10:37-38.
[39] As VECC correctly points out in their Final Argument, her overall opinion is also not useful because she has given evidence supporting lower equity thicknesses and ROEs for generation utilities with higher business risks.
[40] Tr. 10:99-100.
[41] Tr. 10:102-113.
[42] Tr. 10:103. Less than half of the MW are peaking.
[43] Tr. 10:103. Smaller units are usually run of the river.
[44] Tr. 10:104. Concentrated on a small number of river system.
[45] Tr. 10:105. Most of the Newly Regulated Hydroelectric rate base is larger facilities.

(e) Smaller facilities are riskier[46].

(f) The water use constraints on the rivers of the Newly Regulated are greater than Niagara Falls and the St. Lawrence River[47].

(g) Production variability in the newly regulated implies higher flow variability[48].

(h) First Nations issues are a bigger risk for the newly regulated than for the previously regulated[49].

3.1.10 There are other examples, but the overall conclusion the Board must reach is that Ms. McShane is not an expert in hydroelectric operations[50], and she has insufficient knowledge of the actual business risks of the newly regulated hydroelectric facilities to form any independent opinion (see above).

3.1.11 SEC therefore concludes that the Board can place no weight on the opinion of Ms. McShane that the Newly Regulated Hydro Electric facilities are more risky than the Previously Regulated Hydroelectric facilities.

3.1.12 The Board has no other evidence on this point, and so the simple solution would be to treat the Newly Regulated as having equal risk to the Previously Regulated.

3.1.13 In SEC's submission, such an assumption would, if anything, overestimate the risks of the Newly Regulated facilities. We tend to think of the stability of production from Sir Adam Beck and Saunders as being indicative of lower risk, but in an era of Surplus Baseload Generation, the opposite is actually true. Risk is minimized in that context by agility. Many of the Newly Regulated facilities have exactly that, because their ability to hold water back behind a dam allows them to avoid the negative impacts of nuclear lack of flexibility. Niagara and Saunders may have to spill water; facilities with dam storage are less likely to do so.

3.1.14 SEC therefore submits that, in the absence of evidence to the contrary, the Board should treat the Newly Regulated Hydroelectric facilities as having the same business risk as the Previously Regulated Hydroelectric facilities.

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[46] Tr. 10:105. Smaller units are designed to run remotely.
[47] Tr. 10:106-7. Niagara and St. Lawrence water use constraints are amongst the tightest in Canada.
[48] Tr. 10:107-8. In fact, it implies dam storage, and therefore ability to maximize value, which is an advantage, not a risk. Flow variability is <u>less</u> of a problem when there is a substantial headpond.
[49] Tr. 10:108-111. OPG has been largely successful – with the government's assistance - in improving its relationships with First Nations in the north, including partnerships with key groups, such as on the Mattagami. OPG remains at risk in the south, where it has two major facilities (Saunders and Sir Adam Beck) near First Nations with highly militant residents. Ms. McShane was not aware of any of this.
[50] Which she openly admits: Tr. 10:103.

3.1.15 ***Darlington Construction Costs.*** Ms. McShane claims that the large financial commitments relating to the Darlington Refurbishment increase business risk, and therefore increase the necessary equity thickness[51].

3.1.16 The difficulty with this assertion is the construction costs are not part of rate base, and are not financed, for regulatory purposes, using a combination of debt and equity. It is a general ratemaking principle of the Board[52] that the responsibility of ratepayers to pay a fair return on the cost of assets commences when the assets are placed into service, so that the ratepayers are receiving a benefit (for which they pay the fair return). Until that time, the financing cost associated with assets under construction is treated as part of the accruing capital cost of the assets.

3.1.17 There are exceptions to this rule, such as the discretionary inclusion in rate base of construction work in progress (CWIP). OPG in fact asked for CWIP in rate base treatment in EB-2010-0008, but the Board rejected that proposal as being premature[53]. Although they could have re-applied in this proceeding[54] they did not.

3.1.18 What Ms. McShane now proposes is that, while OPG may not receive an equity return on their Darlington CWIP, that CWIP should at least be treated as being included in rate base for the purpose of determining equity thickness.

3.1.19 In SEC's submission, this is inappropriate. If OPG wants to include CWIP in rate base for any purpose, they should file the evidence the Board said in EB-2010-0008 would be required, and let the Board make that determination. Getting it included in rate base partially, in effect through the back door, is not the right way to go about it.

3.1.20 ***Future Changes to Business Risks.*** Ms. McShane notes in her expert paper[55] that, when Darlington Refurbishment is completed, and other changes are made to the mix of assets, over the period 2016 through 2022, the generation mix will change again, and the business risk will therefore also change. Her conclusion is that the Board should not change the equity thickness now, because it may have to change back in the future.

3.1.21 SEC acknowledges that, if the regulation of the refurbished Darlington follows the same pattern as the current prescribed facilities, that would imply an increase in business risk, and therefore an increase in equity thickness. It is not, however,

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[51] Tr. 10:40-41
[52] See *Northwestern Utilities Ltd. v. Edmonton (City)*, [1929] SCR 186, p. 190. Further, in Ms. McShane's expert report in EB-2007-0905, even she admitted that "OPG is entitled to the opportunity to earn a fair return on the assets that are devoted to, and are used and useful in, the provision of regulated service, i.e., its rate base." (see EB-2007-0905 C2/1/1/, p. 5)
[53] EB-2010-0008, p. 78.
[54] With much better evidence of the value to ratepayers, as the Board said in EB-2010-0008 would be required.
[55] L/3.1/17-SEC-24, Attachment 1, p. 16.

appropriate to assume the net future result today, for two reasons.

3.1.22 First, the Board is not setting equity thickness for 2022. It is setting the equity thickness for 2014 and 2015. In future cases, there may be different mixes of generation, and different business risks. Those will be dealt with by those Board panels.

3.1.23 We note, in this regard, that in the last rate case, when the Niagara Tunnel was under construction, OPG did not propose that the Board consider the upcoming impact of that project on business risks.

3.1.24 Second, this Board panel has no evidence before it as to the business risks in future years, after 2015. The Board may expect that, directionally, business risks will go up, but it has no way of knowing, today, what the actual level of business risk will be at that time.

3.1.25 For example, the Board has a schedule of Darlington in-service dates and costs, but does anyone – even OPG[56] – believe that the Darlington Refurbishment will come in exactly on schedule, and at exactly those costs? Everyone agrees, we think, that there will be material cost and timing differences in practice, and therefore the generation mix in any given future year is entirely unknown.

3.1.26 Of course, that also would assume that Darlington, as refurbished, will be regulated in exactly the same way as the current prescribed facilities. It is at the very least reasonably possible – particularly if there are significant cost overruns – that the government will change the regulatory framework within which OPG recovers its Darlington costs[57]. Any such change might well increase or decrease business risks to a great extent.

3.1.27 We also don't know what other generation projects will be implemented by OPG. Will they develop further hydroelectric potential, either on their existing rivers or on new rivers? Will those assets be prescribed?

3.1.28 The generation mix, and the business risks, in future years are currently unknown, and the Board has no information before it on which to make assumptions about future decisions on equity thickness. There is a reason those decisions will be made by future Board panels: it will be those Board panels that have the relevant evidence before them.

3.1.29 ***The Spectre of IRM***. Finally, Ms. McShane expressed her concern that the imminent requirement that OPG enter a period of IRM will increase its business

[56] See Tr. 16:9.
[57] As they did when the original Darlington project went so far over budget that it threatened the viability of the former Ontario Hydro.

risks[58].

3.1.30 There are two reasons why this is irrelevant today.

3.1.31 First, as VECC correctly points out in their Final Argument, IRM is intended to give companies more freedom to increase their returns through efficiencies. In the long term, increasing the structural ability to generate higher returns should reduce business risk.

3.1.32 Second, as with the issue of future generation mix, IRM is an issue for future proceedings. If OPG believes that under IRM it has higher risk, and so should have a higher equity thickness, then the time to make that argument, and provide evidence to back it up, is in the proceeding that establishes the terms of their IRM. Incorporating the future possibility of IRM into today's equity thickness is simply premature.

3.1.33 ***Calculation of Appropriate Equity Thickness***. In EB-2007-0905[59], the Board established the 47% figure, and did so on the basis of the ratio of nuclear assets in rate base (at a conservative 50% equity thickness), and hydroelectric assets in rate base (at a more traditional 40% equity thickness). In EB-2010-0008, the Board decided to retain the same equity thickness[60].

3.1.34 We note that, in EB-2010-0008, the Board expressed some concern for the potential that equity thickness could be volatile and complex as generation mix changed. However, their concern arose entirely within the context of a proposal to have separate, technology-specific equity thicknesses. The Board was concerned that, if the 47% aggregate figure remained unchanged, the technology-specific figures proposed by some would have to change more dramatically to get the right common result[61]. The Board concluded this may not be desirable, and made clear that changes in overall business risk must still govern equity thickness. This is one of the reasons technology-specific equity thicknesses were rejected.

3.1.35 SEC believes that the business risk of the prescribed facilities has changed dramatically with the addition of the Newly Regulated Hydroelectric facilities, and the Niagara Tunnel. Further, we believe that the appropriate way to adjust for this change is to use the same approach as was approved in EB-2007-0905.

3.1.36 While we believe that the 50% equity level for nuclear is likely too high, that is what the Board used in that case, and in the absence of evidence to the contrary in

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[58] L/3./17-SEC-24/Attachment 1, p. 16-17.
[59] EB-2007-0905 Decision, p. 149-50.
[60] EB-2010-0008 Decision, p. 116. The Board declined to set separate, technology-specific equity thicknesses, as some parties proposed, but did support the existing combined equity thickness, based on the analysis in the earlier decision.
[61] EB-2007-0905 Decision, p. 117.

this case, that is what we believe the Board should use here.

3.1.37 In the result, SEC believes that the appropriate equity thickness for the test period is

OPG Adjusted Equity Thickness

Category	**Rate Base**						**Equity**	**Weight**
	2014		**2015**		**Average**	**Percent**		
Previously Regulated Hydroelectric		$5,128.0		$5,084.6	$5,106.3			
Newly Regulated Hydroelectric		$2,511.5		$2,528.2	$2,519.9			
Subtotal		$7,639.5		$7,612.8	$7,626.2	76.57%	40%	0.306276
Nuclear - Gross	$3,706.7		$3,659.0					
Adj. for Lesser of UNL/ARC	-$1,389.5	$2,317.2	-$1,308.8	$2,350.2	$2,333.7	23.43%	50%	0.117155
Totals		$9,956.7		$9,963.0	$9,959.9			42.34%

42.34%, calculated as follows:

3.1.38 We note that this calculation relies on the final rate base figures for the test period. Elsewhere in this Final Argument, SEC has proposed adjustments to rate base of various types.

3.1.39 In our submission, if rate base is changed by the Board in its decision, then the equity thickness should be recalculated using the final approved rate base for each year. That would likely result in a slightly higher equity thickness than we have calculated**.**

3.2 ***Return on Equity Proposal***

3.2.1 ***ROE Rate.*** SEC has reviewed the submissions of Board Staff on the Applicant's ROE proposal[62]. Staff proposes that the Board set the 2015 ROE for OPG using the Board's own calculations based on the Consensus Forecasts, which should be available in October or November.

3.2.2 SEC agrees that this is a better approach than the Applicant's proposal, which relies on much older data from Global Insights.

3.2.3 ***Exclusion of FMV Bump in ROE Calculation***. Environmental Defence has proposed, in their Final Argument[63], that the Board not approve any ROE for the portion of the Newly Regulated Hydroelectric rate base that represents the fair

[62] Staff Submission, p. 9-10
[63] ED Final Argument, p. 16-17.

market value bump at the time the assets were acquired from Ontario Hydro.

3.2.4 SEC has some sympathy with the thrust of this argument. There is little question that the application of full cost of capital (as opposed to simply debt, as proposed by ED) represents a windfall to OPG. Indeed, that is applicable not just to the $1.5 billion or so bump in the value of the Newly Regulated assets, but also the $3.5 billion or more bump on the value of the Previously Regulated Hydroelectric. It would appear to us that something approaching half of the Applicant's hydroelectric rate base represents money they didn't actually spend.

3.2.5 That having been said, SEC cannot agree with the ED proposal. In our view, the spirit of the government's restructuring of the former Ontario Hydro, as expressed in the applicable regulations[64], is that OPG will have a fresh start, with a more reasonable level of debt, and more reasonable asset values. The whole point was to free OPG up from some of its history, and allow it to succeed or fail with a viable balance sheet.

3.2.6 As much as we would like to deny OPG any "windfall profits", we think the government's intent was that, on a go-forward basis, they be regulated in the normal way. The ED proposal would have the effect of reaching back into the Ontario Hydro days, taking away some of the benefit of the revaluation of OPG's assets at the time of restructuring. If that had been intended by the government, in our view they would have said so explicitly[65].

3.2.7 Consistent with our position on deferred taxes[66], SEC believes that the Board should accept the incoming balance sheet at face value for regulatory purposes, and should not look behind the individual assets to characterize them differently because of their history.

3.2.8 ***CME Alternative.*** SEC has been given an opportunity to review the draft submissions of CME on this question. CME has taken a different approach from either ED or SEC, arguing that the capital supporting the Newly Regulated Hydroelectric assets is stranded debt. Their analysis, which is presented as alternative to, and not incremental to, the 42-43% equity thickness SEC and VECC have proposed, would apply a debt rate to the Newly Regulated Hydroelectric assets, but leave the equity thickness for the remaining assets at 47%.

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[64] O.Reg 53/05.

[65] We have no doubt that ED's analysis of the wording of the regulations is technically correct. The reg. could have required the Board to treat all assets on the balance sheet as equal for rate base purposes, and it did not. It is correct to say it is silent on return. However, the overall spirit of the provision, in our view, is more consistent with normal rate base treatment than with some form of special rule for the FMV bump.

[66] See Section 6.13. OPG brings in new assets that have had related expenses already made, and liabilities thus accrued, for deferred taxes. From an accounting point of view, that is money already spent. Those should not be re-characterized as future costs, just as asset book values should not be re-characterized as a "special" kind of rate base.

3.2.9 In our view, the CME analysis is generally consistent in principle with our analysis above. That is, both accept the "fresh start" interpretation of O.Reg.53/05. CME has proposed a different way to achieve that principle than SEC. If the Board rejects our proposal to rebalance the equity thickness to reflect the new asset mix, then SEC believes that the CME approach has merit as a principled alternative.

3.3 ***Cost of Debt***

No submissions.

4 CAPITAL PROJECTS

Regulated Hydroelectric

4.1 *Section 6(2)4 Costs – Regulated Hydroelectric*

4.1.1 No additional submissions.

4.2 *Capital Expenditures and Commitments – Regulated Hydroelectric*

4.2.1 See our submissions with respect to Issue 4.3.

4.3 *Test Period In-Service Additions – Regulated Hydroelectric*

4.3.1 SEC submits that the Board should reduce the amount of in-service capital additions for Hydroelectric during the Test Period, as the forecast amount is overstated.

4.3.2 As illustrated by the table below, over the past number of years, OPG has regularly, and in aggregate, over-forecast its in-service additions for hydroelectric capital. On average, OPG brought into service 72.8% of its budgeted[67] capital in the period 2010-2013:

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

4.3.3 While OPG only tracked in-service additions for its previously regulated facilities, a review of actual versus budgeted amounts for capital expenditures shows a similar trend of over-forecasting. On average, OPG only spent 83.3% of its budgeted capital in the period 2010-2013. It in fact underspent its planned amount in each of the past four years, as shown on the table below:

[67] Which includes Board-approved, where applicable.

Capital Expenditures (excluding NTP) ($M)					
	2010	**2011**	**2012**	**2013**	***Average***
Previously Regulated Plan	53.5	39.9	36.8	33.8	*41.0*
Previously Regulated Actual	40.4	35.3	29.8	26.7	*33.1*
Newly Regulated Plan	80.2	76.7	91.4	71.4	*79.9*
Newly Regulated Actual	68.6	61.4	80.1	60.5	*67.7*
Total Plan	133.7	116.6	128.2	105.2	*120.9*
Total Actual	109	96.7	109.9	87.2	*100.7*
Actual/Plan (%)	***81.5%***	***82.9%***	***85.7%***	***82.9%***	***83.3%***
Source: D1/1/2/Table 5. L/1.0-Sch 1 Staff-002/Attach 1/Table 2 (2013 Actuals)					

4.3.4 There is nothing in the evidence showing that OPG either:

(a) has corrected for its previous over-forecasting of capital additions and expenditures, or

(b) now believes that it has an improved capability to execute its ambitious test period hydroelectric capital program.

4.3.5 Since newly regulated facilities were never budgeted on an in-service additions basis in the past, SEC submits that the Board should apply the percentage of actual capital expenditure versus planned capital expenditures for both previously and newly regulated hydroelectric facilities as a proxy for the expected % of actual in-service additions that OPG will bring in service, relative to forecast.

4.3.6 Using this method, SEC submits that the Board should approve 83.3% of OPG's planned hydroelectric capital additions (excluding the Niagara Tunnel Project) for the Test Period as reasonable and appropriate. This would result in approved amounts of $70.1 million for 2014 and $126.2 million for 2015, reductions of $14.0 million and $25.3 million respectively.

4.4 *Section 6(2)4 Costs – Niagara Tunnel*

4.4.1 ***Overview.*** OPG is seeking to include in rate base the full $1,472 million cost of the Niagara Tunnel Project, which is $486.8 million more than the original forecast approved by its Board of Directors[68]. SEC submits that OPG's actions in the planning of the project, and its actions in renegotiating the contract with Strabag AG ("Strabag") when serious tunneling issues occurred, were unreasonable and imprudent. While it is impossible to quantify with precision the total additional

[68] And subject to Section 6(2)4 of O.Reg 53/05.

costs incurred as a result of OPG's imprudent actions, SEC submits that the Board should disallow a reasonable estimate of those additional costs, i.e. 50% of the total cost overrun.

4.4.2 The Niagara Tunnel Project was approved as an approximately 10 km new diversion tunnel (with associated support facilities) to bring an additional 500 m^3/s from the Niagara River to Sir Adam Beck GS complex. The project was expected to increase production at SAB GS by roughly 14%, or 1.5 Twh. In July 2005, the OPG Board of Directors approved a budget of $985.2M for the project with a planned in-service date of 2010 (both include contingencies).[69] OPG awarded a Design Build Agreement (DBA) to Strabag, and retained Hatch McDonald to act as the Owner's Representative, which would include project management, design review, and construction oversight.[70]

4.4.3 Significant tunneling challenges occurred as the tunnel boring machine entered the Queenston shale formation due to excessive rock overbreak, large block failures and insufficient stand-up time. Strabag alleged that these constituted a Differing Subsurface Condition[71] that would allow them to claim cost and schedule adjustments. OPG disagreed and, after negotiations failed, the matter was referred to the Dispute Review Board, a non-binding dispute mechanism provided for by the DBA.

4.4.4 The Dispute Review Board made a number of findings, including a finding that Differing Subsurface Conditions did occur with regards to certain claims. It also made a number of findings critical of the Geotechnical Baseline Review contained in the contract ("GBR-C) and findings that both parties must accept responsibility for some of the additional cost. Of Strabag's five claims of Differing Subsurface Conditions, the Dispute Review Board found in its favour with respect to the most far reaching and significant claim – the excessive overbreak.[72] It also found, with respect to an inadequate Table of Rock Conditions and Characteristics, that the language of the Geotechnical Baseline Report (GBR) rendered the concept of a Differing Subsurface Condition "essentially meaningless".[73]

4.4.5 In the spring of 2009, OPG and Strabag subsequently renegotiated the DBA and entered into an Amended DBA ("ADBA") which shifted the contract from a fixed price to target price agreement. OPG's Board of Directors approved the approach and the revised in-service date of 2013, and approved up to $1.6 billion in total spend, which at the time was the new forecast cost.[74]

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[69] D1/2/1.
[70] D1/2/1, p. 45.
[71] This term is defined in the DBA.
[72] Dispute Review Board Report, D1/2/1/Attachment 7, p. 18-19.
[73] Dispute Review Board Report, D1/2/1/Attachment 7, p. 19.
[74] D1/2/1-Attachment 9.

4.4.6 A project the size and scope of the Niagara Tunnel Project is challenging and complex. Because of this, a greater the focus should be placed on risk mitigation and management. OPG, who are seeking to recover the money from ratepayers who have had no say in the actual approval of the project, must undertake the project in a reasonable and appropriate manner at every step.

4.4.7 OPG did not do so and ratepayers should not have to bear the cost of the full cost overrun. Specifically, OPG did not conduct adequate geotechnical investigations, allocated too much of the risk to itself, partly through the defective Geotechnical Baseline Review, and negotiated a revised contract (the ABDA) that increased the cost by roughly 50%. Ratepayers should not have to bear the cost of the imprudent actions of OPG which led, in part, to this cost overrun.

4.4.8 ***Geotechnical Investigations.*** Between 1983 and 1993, OPG's predecessor Ontario Hydro conducted various geotechnical investigations for a previous iteration of the project, which would have seen the building of two additional tunnels to Sir Adam Beck GS No. 2, as well as a new underground generating station.[75] Those preliminary geotechnical investigations during both the concept and definition engineering phases included the testing of 59 boreholes and a geotechnical adit.[76] OPG did not undertake any other geotechnical investigations after 1993, including drilling of any more boreholes.[77] Of the 59 that were drilled based on an out of date configuration, only 20 were ultimately along the proposed tunnel route for the Niagara Tunnel Project.[78]

4.4.9 OPG was under pressure to complete the project in the "shortest possible time" by the Government of Ontario, through the Ministry of Energy.[79] Further, geotechnical investigations would have taken more time and that would have extended, potentially significantly, the time frame for completion of the project.[80]

4.4.10 SEC submits that OPG did not conduct adequate geotechnical investigations. With a project the size and scope of the Niagara Tunnel, it was imprudent for OPG not to conduct any further geotechnical investigations after 1993, a total of over a decade before construction ultimately was completed. Further geotechnical investigations, especially additional boreholes along the actual final route, likely would have provided not just more, but also up-to-date information about the rock conditions that ultimately were the major cause of the significant cost overrun. While Mr. Ilsley stated that there had not been any changes to investigative or technological

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[75] D1/2/1, p. 146.
[76] OPG also utilized geotechnical information acquired during Ontario Hydro's constriction of the original Sir Adam Beck No. 2 tunnels. That information was from over 50 years earlier, based on a completely different construction method (drill and blast, and was not located in the Queenston shale formation. (see L/4.4/Staff-21)
[77] L/4.5/17-SEC-44.
[78] Tr. 2:45-46. Tr. 3:115.
[79] D1/2/1/Attachment 3 *Project Execution Plan – Appendix A – Project Charter (December 23, 2005),* p.3.
[80] Design Build Agreement, section 5.4, D1-2-1-Attachement 6.

tools for geotechnical investigations since 1993, he could not confirm that this was the case regarding testing protocols.[81]

4.4.11 ***Geotechnical Baseline Report was Defective.*** SEC submits that the Geotechnical Baseline Report (GBR-C) was misleading, ambiguous and - ultimately - defective. The purpose of a Geotechnical Baseline Report is to allocate risk between the project proponent (OPG), and the contractor (Strabag). By contractually defining the anticipated ground conditions, the risk of tunnel drilling and construction problems are allocated between the two parties.

4.4.12 The development and agreement of the final Geotechnical Baseline Report (the GBR-C), while usually aided by experts retained by the parties, is not an independent third-party report.[82] It is done through negotiation between the proponent and the contractor. OPG prepared an initial Geotechnical Baseline Report (GBR-A) which was provided to all bidders who took part in the Request for Proposal process. Those who responded provided a response (GBR-B). During the negotiations of the successful bidder, a final Geotechnical Baseline Report (GBR-C) was negotiated and became part of the final DBA.

4.4.13 An example of the concerns with negotiations was the amount of allowable excessive overbreak[83]. In the Geotechnical Baseline Report (GBR-A), OPG had estimated this amount to be 45,000m^3. Strabag in turn responded in its Geotechnical Baseline Report (GBR-B) with an amount of 15,000 m^3. The parties split the difference and negotiated an amount of 30,000 m^3, which was incorporated into the contract through the Geotechnical Baseline Report (GBR-C). The amount ended up being 60,000 m^3, which was double what was in the Geotechnical Baseline Report (GBR-C), but much closer to what OPG had originally expected. Reducing the amount of allowable overbreak through negotiation had the effect of increasing OPG's risk, and thus benefited Strabag.

4.4.14 Section 5.4 of the DBA provides that the Geotechnical Baseline Report (GBR-C) will be used to compare the actual subsurface conditions with the assumed subsurface conditions. If the actual subsurface conditions are more adverse than the assumed subsurface conditions as defined in the Geotechnical Baseline Report, then any construction cost consequences will be borne by OPG. This is what became known as a Differing Subsurface Condition. On the other hand, if there are construction cost overruns, but the actual subsurface conditions are equal or less than the subsurface conditions assumed in the Geotechnical Baseline Report (GBR-C), those costs would be borne by Strabag.

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[81] Tr. 2:66,68-69.
[82] OPG had Hatch Macdonald, as Owners Representative, help develop the Geotechnical Baseline Report. (Tr. 2:39-40)
[83] This is, in essence, the extent to which rock from the top of the tunnel is expect to fall during tunnelling.

4.4.15 The Geotechnical Baseline Report (GBR-C) became a focal point in the dispute between Strabag and OPG. When problems were encountered in the excavation of the Queenston shale, Strabag claimed a Differing Subsurface Condition. Parties turned to the non-binding Dispute Review Board, which made a number of important findings, not just about the merits of Strabag's claim of a Differing Subsurface Condition, but about the Geotechnical Baseline Report (GBR-C) itself.

4.4.16 OPG's expert witness, Mr. Ilsley, agreed that the Geotechnical Baseline Report (GBR-C) was ambiguous.[84] The terminology used by the Geotechnical Baseline Report (GBR-C) did not follow proper guidelines, as the language used was imprecise and too broad to describe critical issues. During the oral hearing, Mr. Ilsley specifically referenced the American Society of Civil Engineers guidelines for Geotechnical Baseline Reports for construction.[85] Those guidelines were also referenced in the Dispute Review Board Report.[86] We have attached the appropriate excerpt from those Guidelines as Appendix A to this Final Argument.

4.4.17 Those guidelines are clear that a Geotechnical Baseline Report should not use ambiguous words to describe ranges of rock conditions:[87]

> *"The use of words such as "may,", "can," "might," "up to," "could," "should," "some," "few,", "ranges from…to….," and "would" are imprecise, and must not be used in baselines statements. Better words include "is," "will," and "are". The use of such definitive terms clearly establishes the intended baselines?*
> *…..*
> *The use of adverbs should be avoided. The use of adjectives such a "large," "significant," "local", "many", and "minor" should either be quantified or avoided."*

4.4.18 The Geotechnical Baseline Report (GBR-C) is not in compliance with those guidelines. It is replete with ambiguous language. The Dispute Review Board findings provide several examples of this problem, and these were integral to the eventual dispute between OPG and Strabag. The Geotechnical Baseline Report (GBR-C) included ambiguous language such as "a potential for", "generally" and "can". [88] The Dispute Review Board finds because of this, "[t]he Contractor and Designer could have also been misled."[89]

[84] Tr. 2:55.
[85] Tr. 2:50.
[86] Dispute Review Board Report, D1/2/1/Attachment 7, p. 14-15.
[87] *Geotechnical Baseline Reports for Constriction: Suggested Guidelines,* American Society of Civil Engineers (ASCE), p. 27 (See Appendix A).
[88] Dispute Review Board Report, D1/2/1/Attachment 7, p 14, referencing section 8.12, 8.1.2.3, and 8.1.3.2 of the GBR-C.
[89] Dispute Review Board Report, D1/2/1/Attachment 7. p. 14.

4.4.19 The Dispute Review Board's findings are clear. OPG (and its Owner's Representative, Hatch MacDonald), and Strabag had a number of misunderstandings that were based on misinterpretations of the Geotechnical Baseline Report (GBR-C) that led to the dispute about the subsurface conditions that would be anticipated in the Queenston shale. Since OPG bore the risk for cost consequences of a Differing Subsurface Condition, it should not have agreed to a Geotechnical Baseline Report (GBR-C) that included ambiguous language. In agreeing to the ambiguous language, it did not adhere to the proper guidelines cited by the Dispute Review Board and OPG's own expert Mr. Ilsley.

4.4.20 With respect to the issue of excessive overbreak, the Dispute Review Board found that the provisions in the Geotechnical Baseline Report (GBR-C) made it defective and that the DRB had to overlook some of its statements to find a Differing Subsurface Condition.

4.4.21 Further, with respect to the inadequate Table of Rock Conditions and Rock Characteristics, the Dispute Review Board found that the Geotechnical Baseline Report (GBR-C) made important elements of it wholly meaningless.

> "The Table of Rock Conditions and Rock Characteristics is inadequate to define the subsurface conditions that were encountered. More importantly, the classification of support types based on the "closest match" to rock conditions and rock characteristics given in this Table, together with rock characteristics defined as "all other conditions", renders the concept of DSCs essentially meaningless and the <u>GBR defective</u>." [emphased added] [90]

4.4.22 While ultimately the Dispute Review Board placed the blame on both OPG and Strabag for the Geotechnical Baseline Report (GBR-C) deficiencies, ratepayers should not have to bear the cost of OPG's entire share of the responsibility of its consequences. The Dispute Review Board Report made explicit findings on significant inadequacies of the Geotechnical Baseline Report (GBR-C), finding it deficient. While OPG might not have sole responsibility for this, it must share the responsibility for ensuring that this foundational document appropriately reflected a clear understanding of the reasonably expected rock conditions that would be faced. It ultimately did not do that.

4.4.23 OPG did not conduct an independent assessment of the final Geotechnical Baseline Report (GBR-C) to ensure it adequately allocated risk. In addition, and likely more important, OPG did not ensure that the language was clear, unambiguous, and followed proper industry guidelines, to ensure that it actually protected itself against the risk it believed it had allocated between itself and Strabag.

4.4.24 ***Hatch Liability.*** SEC submits that OPG should have taken legal action against its

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[90] Dispute Review Board Report, D1/2/1/Attachment 7, p. 19.

Owner representative, Hatch Mott MacDonald, who were not only integral in preparing the Geotechnical Baseline Report (GBR-C)[91], but also heavily involved in the geotechnical investigations[92]. Despite this, Hatch was never sued for negligence. While OPG's witnesses stated they did not have a cause of action[93], they admitted OPG never really considered the issue.[94] SEC submits that since OPG retained Hatch MacDonald as Owner's Representative, to prepare the Geotechnical Baseline Report, it clearly did so because Hatch had the expertise that OPG internally did not. Since the Geotechnical Baseline Report (GBR-C) did not accord with industry guidelines and was found to be defective, SEC submits OPG likely did have a claim against Hatch Macdonald. At the very least should have investigated the matter fully.

4.4.25 At the very least, OPG should have used Hatch Mott Macdonald's potential liability as leverage in renegotiating its contract with them. Ultimately, Hatch MacDonald made $15 million more, as the project's duration was extended and further activities were required from the Owner's Representative.[95]

4.4.26 ***Inadequate Risk Evaluation and Mitigation.*** SEC submits OPG's risk evaluation and mitigation activities were inadequate.

4.4.27 In its original Business Case to the Board of Directors, OPG provided a project risk table.[96] The table identified some 20 types of risks, a description of their consequences, the mitigation activities that were being, or would be, undertaken, and the level of risk before and after mitigation.

4.4.28 The only risk that after mitigation remains at the level of at least 'medium' is that of "the contractor may encounter subsurface conditions that are more adverse than described in the Geotechnical Baseline Reports (GBR). This is the risk that ultimately materialized. All the other risks, which were identified as 'high' before mitigation, were all lowered to 'low' after mitigation activities.

4.4.29 When questioned about this at the oral hearing, OPG witnesses stated that the cost would have been prohibitive to undertake further geotechnical investigations over what had been done already.[97] But ultimately they did not even consider anything more than the geotechnical investigations that had been undertaken before 1993, the Geotechnical Baseline Report process, and a budgeted contingency amount:[98]

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[91] Tr. 2:37,39.
[92] D1/2/1, p.136, Tr. 2:37. Acres became Hatch Mott MacDonald.
[93] Tr. 2:38.
[94] Tr. 2:71-72
[95] D1/2/1-Table 6, p. 113. Tr. 1:77.
[96] D1/2/1/Appendix C, p. 1.
[97] Tr. 2:62.
[98] Tr. 2:63.

> *"MR. RUBENSTEIN: So at the time, you didn't actually even consider anything more than the mitigation activities that are set out here?*
> *MR. YOUNG: I believe that's correct."*

4.4.30 OPG's own original Business Case reflected a 10% chance that its Geotechnical Baseline Report would be wrong.[99] Considering that for any underground tunneling project, differing subsurface conditions is usually the most significant project risk, SEC submits OPG acted unreasonably in failing to require further mitigation activities.

4.4.31 SEC has had a chance to review the draft submissions of AMPCO and adopts its submissions with respect to the deficiency of the URS risk assessments. Specifically, that it appears that OPG only identified the risk of <u>higher</u> rock strength.[100] Ultimately, the Differing Subsurface Condition was partially due to <u>lower</u> than expected rock strength. The URS risk assessment was how OPG determined its project confidence level (90%) and the corresponding contingency amount ($96M).[101] A proper consideration of both higher and lower rock strength would have yielded a lower confidence level and higher contingency amount, and would have reasonably led OPG's board to require greater mitigation activities.

4.4.32 ***Renegotiation of the Agreement.*** SEC submits that OPG was not prudent in its renegotiations with Strabag that culminated in the ADBA (and its subsequent amendments). The ADBA changed the agreement from one of a fixed price arrangement with Strabag, to one of target pricing. This had the effect of dramatically changing the risk allocation between OPG and Strabag. OPG has claimed that the impetus of the renegotiation was fear that Strabag would walk off the job after it had made a claim of $90M in losses.[102] If they did, it would leave OPG in a position of having an unfinished tunnel and having to re-tender the work which in its view would likely lead to significantly increased costs.

4.4.33 SEC submits the fear of Strabag simply walking off the job was at best very overstated, at worst wholly unreasonable. Strabag is an international construction company with significant experience undertaking very large construction projects. That is one of the reasons OPG selected them in the first place. OPG was not aware of <u>any</u> history of walking away from projects.[103] Strabag had provided a parental guarantee, letters of credit, and a security bond. Yet, that was not enough to satisfy OPG.[104] Further, if Strabag had walked away from a project, one in which a Design Review Board had apportioned blame to them, they would have suffered significant

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[99] Tr. 2:131. D1/2/1/Attachment 5, p. 9.
[100] D1/2/1/Attachment 3, p. 3.
[101] D1/2/1/Attachment 3, p. 1.
[102] Tr. 1:78-79.
[103] Tr. 2:155.
[104] Tr. 2:152-53.

reputational history and be open to significant litigation risk.

4.4.34 In the renegotiation agreement, OPG's resolution of Strabag's claim of $90M loss up to November 2008 was also unreasonable. The agreement provided that OPG would pay Strabag $40M and OPG had the right to audit Strabag's losses and to the extent that it could not substantiate the full $90M, it was allowed to reduce the $40M payment proportionately. The resolution was imprudent for two reasons:

- The $90M was an imprudent starting point for negotiations. The Dispute Review Board ruled in OPG's favor on three of five of Strabag's claims. In the two where it did find that there were Differing Subsuface Conditions, it stated that the fault should be shared between the two parties. SEC submits that the starting point for negotiations should have been some number significantly below the $90M amount claimed.

- OPG paid more than it was contractually required to pay. When OPG did audit Strabag's loss, it was only able to substantiate $77.4M of the claimed $90M loss. Under the agreement, OPG then had the right to reduce its payment by $5.6M, yet it chose not to. SEC submits this was an imprudent and irresponsible decision by OPG.

4.4.35 OPG's own oversight of the renegotiations with Strabag was inadequate. OPG management did not provide its Board of Directors with a sufficient number of options for how to move forward when it sought approval of the ABDA. In its May 2009 Business Case Summary OPG only provided a limited number of alternatives to its suggested course of action. It only provided three alternatives, none of which it recommended, from the proposed target cost ABDA. No other proposals for alternative arrangements were provided to the Board of Directors. OPG's management negotiated an agreement with Strabag in the fall of 2008 (November 2008 Principles of Agreement)[105] and winter of 2009 (Term Sheet signed on February 9, 2009[106] and Memorandum of Understanding signed February 24, 2009[107]). The Board of Directors were provided with an agreement that was for all intents and purposes a *fait accompli*. It does not appear that OPG ever considered other options including, for example, a revised or amended fixed price contract.

4.4.36 While OPG states that the entirety of the cost overrun is attributable to the construction challenges that were encountered in tunneling in the Queenston shale, there is no definite attribution of overruns to each of the specific claims made by Strabag. The evidence is clear, though, that the cost of profile restoration was done "primarily to correct overbreak".[108] OPG calculated the amount of the profile

[105] D1/2/1, p. 106.
[106] D1/2/1, p. 107.
[107] D/1/2/1, p. 108.
[108] Tr. 2:22.

restoration costs to be $92M.[109] The Dispute Review Board found that there was a Differing Subsurface Condition of excessive overbreak but that it should be resolved "based on a fair and equitable sharing of the cost and time impacts".[110] Ultimately, that did not happen, as the whole contract was renegotiated into a target price contract where OPG was responsible for the entire added cost of the contract. A significant portion of the profile restoration costs was because of excessive overbreak.

4.4.37 While OPG seems to have assumed all the added cost, the only consequence that Strabag seems to have assumed from their share of responsibility for the excessive overbreak, is a somewhat lower profit margin.[111] Ratepayers should not have to bear the full cost of this amount, considering the Dispute Review Board recommended OPG and Strabag share the cost responsibility.

4.4.38 Even after the ABDA Agreement was entered into, OPG unreasonably agreed to a further amendment which adjusted the completion date, resulting in a significant increase in the final incentive payment made to Strabag. Instead of receiving what would have been $25 million under the original target substantial completion date, Strabag received $40 million.[112] Clearly, the increase of 17 days under Amendment No. 1 and 94 days under Amendment No. 2 were not required since Strabag met the substantial completion date on March 9th 2013, a completion date that was earlier than the original target date of June 15th 2013 under the ADBA.[113] Ratepayers should not have to bear the $15 million difference caused by OPG's unreasonable concessions to Strabag.

4.4.39 ***Summary.*** SEC submits that OPG should only be able to recover in addition to the amount covered by 6(2)4 of O.Reg 53/05 ($985M) 50% of the cost overrun of $491.4M ($245.7M). This would reflect an appropriate amount that should be borne by OPG's shareholder instead of ratepayers as a result of imprudent actions by OPG at various steps in the development and construction of Niagara Tunnel.

4.5 ***Test Period In-Service Additions – Niagara Tunnel***

4.5.1 See our submissions with respect to Issue 4.4.

Nuclear

4.6 ***Section 6(2)4 and Section 6(2)4.1 Costs - Nuclear***

4.6.1 See Issue 4.7.

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[109] JT2.1 $92,031,850.94.
[110] Dispute Review Board Report, D1/2/1/Attachment 7, p. 18.
[111] Tr. 2:22,143-54.
[112] Tr. 2:36.
[113] D1/2/1, p. 127. Tr. 1:35.

4.7 ***Capital Expenditures and Commitments - Nuclear***

4.7.1 Except with respect to Darlington Refurbishment (see Issue 4.10), we adopt the submissions of Board Staff[114].

4.8 ***Test Period Additions – Nuclear***

4.8.1 Except with respect to Darlington Refurbishment (see Issue 4.9), we adopt the submissions of Board Staff[115].

4.9 ***Test Period Additions – Darlington Refurbishment***

4.9.1 The Darlington Refurbishment project is still in its Definition Phase, and the Applicant is not even ready, yet, to provide a release quality estimate. That is expected in the fall of 2015[116].

4.9.2 Notwithstanding the status of the project, OPG proposes to close capital assets for the Darlington Refurbishment to rate base in the Test Period, and start earning a return on those assets. SEC believes closing certain of those assets to rate base is premature.

4.9.3 The projects and amounts that are proposed to be added to rate base in each of 2014 and 2015 are set out in the following table[117]:

[114] Staff Submissions, p. 30-32.
[115] Staff Submissions, p. 32-31.
[116] J15.2.
[117] D2/2/2, p. 6.

Table 1 – DRP In-Service Amounts

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

4.9.4 The projects that are included in the above categories are variously referred to as the Campus Plan Projects or the Facilities and Infrastructure Projects[118]. Those projects comprise, in aggregate, about 10% of the total cost of the Darlington Refurbishment[119].

4.9.5 The projects included in the proposed- in-service additions are the following:

(a) ***Darlington OSB Refurbishment.*** This is the refurbishment of the existing Operations Support Building. The building is an existing structure that has been in existence for many years, and houses 375 employees who support the Darlington NGS[120]. It would appear to us that, if Darlington were to close in the next few years, this building would not require an extensive refurbishment.

[118] Although those two terms aren't precisely equivalent, they are functionally equivalent for the purpose of this analysis.
[119] D2/2/1, p. 7.
[120] D2/2/1, Attachment 8.04.

However, Darlington's life is expected to be extended, and the building will not be able to survive that additional period without a lot of work. When the refurbishment is completed, which is currently expected in 2015, the building will (continue to be) used and useful for the benefit of ratepayers in support of the energy production from Darlington NGS. SEC therefore has no concern over the timing of the in-service addition. We do, however, have a concern about the $46.8 million total cost[121]. This is essentially an office building, and no details have been provided by the Applicant to show that spending $47 million to update and upgrade an office building is a reasonable amount. The Board has been provided with no evidence, of which SEC is aware, to support the budget, or the figure to be added to rate base. Therefore, SEC believes that the Board should not approve adding this project to rate base in the Test Period. However, it would be reasonable to add this to the Capacity Refurbishment Variance Account, so that when proper evidence is filed in a future proceeding, it can be added to rate base at that time.

(b) ***D2O Storage Facility.*** The D2O Storage Facility will store heavy water removed from each unit during its reconstruction[122]. The forecast cost is $108.1 million, with an original in-service date of October, 2015. However, that is now delayed[123], and the Applicant now expects to close $16.5 million for this project to rate base in the Test Period[124]. SEC submits that this project is an integral part of the Darlington Refurbishment project, much like building a construction office to house supervisory staff during the project. This project would not be built except for the need to store heavy water during construction, and so should be brought into service only as part of the costs of the main project. It is providing no material value to the ratepayers in the meantime.

(c) ***DN Auxiliary Heating System***. This project is adding a new boiler system to provide steam to heat the facility in the event that all four units are shut down during the construction period. The project will ensure that the temperature of the station remains above 10 degrees, thus preventing freezing[125]. This project would appear to be required due to the construction project, and therefore SEC does not understand why it would be considered in-service in 2015, when completed. Further, the evidence before the Board is that the approved cost of this facility is $45.6 million[126], but the Darlington Update has the amount closing to rate base in 2015 as $75.3 million. The only reference to this large cost increase is that OPG has:

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[121] D2/2/1, Attachment 8.04.
[122] D2/2/1, p. 24.
[123] This was the subject of a detailed analysis in the Q4 2013 Modus Report.
[124] D2/2/2, p. 6
[125] D2/2/1, Attachment 8.05.
[126] D2/2/1, p. 26.

> *"an improved understanding of the project estimate for the Auxiliary Heating System, 5 OSB Refurbishment, and Third Emergency Power Generator projects as a result of 6 further project development.*[127]*"*

SEC submits this is insufficient support for a cost increase of almost $30 million. Therefore, SEC submits that, if the Board considers that this project is "used or useful" for the public in the Test Period (which SEC does not believe), then the Board should in any case not approve inclusion in rate base due to the lack of cost support. Instead, the Board should allow this to be added to the Capacity Refurbishment Variance Account, to be reviewed in a future application when the Applicant provides supporting evidence for the cost.

(d) ***Water & Sewer***. This is a project to replace, in stages, the existing fire and potable water, and sewer, systems for the Darlington NGS[128]. The total cost is expected to be $36 million over several years. Those systems were originally built when Darlington was under construction, and they need to be replaced. Although the evidence doesn't say so explicitly, it appears that the rationale for replacing them before the rest of the project is that they are already an urgent problem, and it is better to have good water and sewer systems during the construction phase. It is our understanding that, as sections of this project have been completed since 2011, they are being put into service in support of the existing station operations. During refurbishment, they will support that function, and after the restart they will support the continued operations. SEC has no concerns with treating the completed portions of this project as in-service during the Test Period, nor with the inclusion of parts that came into service up to December 31, 2013 in the Capacity Refurbishment Variance Account.

(e) ***Electric Power Distribution System***. This project is the refurbishment of two on-site distribution stations, and the construction of a new distribution station, as well as repair and maintenance of the related feeders[129]. This is required for two reasons. First, the construction project will add incremental power demand, and the existing system does not have the capacity to handle it. Second, the existing system is old, and so like the water and sewer project it is an appropriate time to renew these assets. Thus, it appears that part should not be brought into service until the main project, since it is providing incremental electrical capacity. However, part should be brought into service now, because like the Water and Sewer project it will be used immediately for existing operations. As the total cost is $12 million, SEC believes that on balance it should be treated as in-service when it is completed in November, 2014.

[127] D2/2/2, p. 7.
[128] D2/2/1, Attachment 8.02..
[129] D2/2/1, p. 26.

(f) ***Darlington Energy Complex***. This is a life-size mockup of the Darlington reactor face, to be used during the construction process to give workers an opportunity to practice in almost real-life conditions, before carrying out the same procedures at that actual reactor face[130]. The amount to be closed to rate base in the Test Period is $6.2 million. SEC believes that this project should not be treated as in-service at this time. The asset is being built as an integral part of the Darlington Refurbishment, and for no other purpose. It is essentially no different from building a scaffolding when you are working on a building. Certainly a scaffolding may be a capital asset, but it is not being used or useful for the public. It is simply one of the costs of building the building. Here, as well, the DEC is simply one of the costs of the Darlington Refurbishment, and should be included in those costs when that project comes into service.

(g) ***RFR Island Support Annex.*** We have been unable to find an explanation of this project. It was not included in the original in-service additions planned for the Test Period, and it is no longer in the in-service additions in D2/2/2. It is one of the key projects in the Campus Plan, and we have found a number of passing references to it, but we have been unable to locate evidence describing it in detail. In any case, since it is not currently expected to close to rate base in the Test Period, in our submission it should not be included in the Test Period in-service additions.

(h) ***Other Campus Plan Projects***. The Applicant proposes to close $22.7 million of some of the 26 Campus Plan projects to rate base in the Test Period. In the original evidence, there was no amount included for this, and no description of these projects. At this point, there only appear to be some limited references to these projects. SEC therefore believes that there is no evidentiary basis on which to close these amounts to rate base.

(i) ***Safety Improvement Opportunities.*** In the prefiled evidence, the Applicant stated that $42.7 million of smaller projects relating to safety improvements at Darlington would be closed to rate base in 2015. That amount was increased without any detailed explanation in N1/1/1 to $90.5 million. The only three projects listed at that time, the Power System Venting System, the Containment Filtered Venting System, and the Emergency Power Generator, are the same as planned in the prefiled evidence. The Darlington Business Case Summary does not have a dollar figure for these projects, nor a line in the overall budget[131]. Based on the information currently before the Board, SEC submits that there is no basis on which to approve any amount to rate base. As with some other components, however, these projects should remain eligible to

[130] D2/2/1, p. 23
[131] D2/2/1, Attachment 5, p. 32.

be added to the Capacity Refurbishment Variance Account, for future clearance on proper evidence.

(j) ***Other Station Modifications***. The Applicant originally proposed to close $13.1 million of miscellaneous (and unstated) station modifications to rate base in the Test Period. That is now zero[132], so SEC submits that no amount should be treated as closing to rate base in this category.

4.9.6 Based on the foregoing analysis, SEC therefore submits that only the Water and Sewer Project and the Electrical Distribution Project should be added to rate base in the Test Period, in the amounts of $22.6 million (2014) and $6.6 million (2015) for Water and Sewer, and $12.0 million (2014) for Electrical Distribution.

4.9.7 The remaining amounts[133] should not, in our view, be disallowed. Rather, addition to rate base should be deferred until proper evidence is provided (in some cases), or until the refurbished units are brought on-stream.

4.10 ***Capital Expenditures – Darlington Refurbishment***

4.10.1 SEC does not believe the Board should give any specific approvals or provide any comments with respect to the $1.7 billion of capital expenditures on Darlington[134] in the Test Period that are not closing to rate base.

4.10.2 In Section 4.11 below, we discuss the continuing attempts by the Applicant to get the Board to "endorse" the Darlington Refurbishment, even though it is clear to everyone that approval of this project – or not - is not currently within the Board's jurisdiction.

4.10.3 With respect to the 2014/15 capex, however, we think the question is simpler.

4.10.4 Either the Applicant wants an approval with meaning (i.e., with teeth), or not.

4.10.5 If the Applicant wants an approval that has some kind of binding effect[135], then the Board would have to wade through all of the evidence on the spending to date, and all of the problems that have arisen so far. That creates two problems:

(a) For $1.7 billion of proposed spending, there is precious little evidence on the prudence of that spending. There is certainly lots of paper on the project itself,

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[132] D2/2/2, p. 6
[133] Which would appear to total $186.9 million ($228.1 million, the total in D2/2/1, less the projects SEC believes should be added, $41.2 million). The increases in N1/1/1, D2/2/1, Attachment 5, and D2/2/2, do not appear to be claimed by the Applicant for ratemaking purposes: see J15.3. If we are incorrect in that assumption, then the reductions in rate base would be greater.
[134] D2/2/2, p. 7, updated estimates.
[135] Which they deny: Tr. 15:132.

and on the various management strategies, etc., but there is very little on which the Board could identify precisely what will be spent in the Test Period (the numbers have had several material changes during the proceeding), and on what (some projects are still being defined), and on whether that spending is prudent given that the final budget of the overall project is not yet known.

(b) The only independent evidence with respect to the work done so far is harshly critical of the performance of the Applicant. There have been very significant cost overruns, and the Applicant freely admits that they have screwed up much of what they have done to date. Thus, the Board can't even start with the (rebuttable) assumption that the utility's proposals for that $1.7 billion are likely OK. No. So far, the Applicant has shown no ability to estimate well, to deliver on time and on budget, and to manage external contractors.

4.10.6 Given the evidence currently before the Board, SEC submits that if the Board had to reaching a binding determination on prudence for this $1.7 billion, it would have to say that prudence has not been shown. On balance, the evidence shows that the proposed spending is not likely to be a correct estimate, and is not likely to be prudently incurred.

4.10.7 That leads to the second alternative, which is that the Applicant does not want or need a binding approval of any type. If that is the case, why would the Board spend the considerable time to weigh the forecast evidence on this spending, only to have to do it all over again with the actual spending the next time around, when it counts?

4.10.8 The obvious answer is that a commentary-style review might provide useful input for the Applicant, to help them manage the project going forward.

4.10.9 In our submission, OPG has shown no desire to have guidance from the Board as to their capital spending plans. They appear to be of the view – which we think is the correct view – that it is not the Board's function to manage the utility. That's what management is there for. The Board is there to set rates, and with limited exceptions the Darlington Refurbishment project has no applicability to rates.

4.10.10 If the Board had the ultimate responsibility to approve the Darlington Refurbishment project, that might be another story. Then it would be the responsibility of the Board to approve the entire budget, and likely also the pace of spending. That is not the case here.

4.10.11 SEC believes that there is no significant value that would arise from a decision to endorse or approve the Applicant's Darlington capital spending in the Test Period.

4.10.12 We do note that, to the extent that the Applicant wanted to get external perspectives on what they are doing, and what issues may arise later, that has already been accomplished. The detailed testing of their Darlington evidence by the parties and by Board Staff, and in particular the questions by Board members of their witnesses, will provide them with useful perspective if they feel it is valuable.

4.10.13 However, asking the Board to take the next step and determine if the proposed capital spending is a good idea is premature, and in our view the Board should not make any such determination at this time.

4.11 ***Commercial and Contracting Strategies – Darlington Refurbishment***

4.11.1 The same issues that are discussed above with respect to the Test Period capital spending arise with respect to the request to approve their commercial and contracting strategies.

4.11.2 We do want to raise an additional issue in this context, though. In the EB-2010-0008 proceeding, the Applicant sought approval to add Darlington CWIP to rate base, prior to the project going into service. Throughout the proceeding, the Applicant repeated many times that it was not asking for approval of the Darlington Refurbishment project by the Board.

4.11.3 Then, late in the day, we asked their witnesses whether the CWIP approval was dependent on the Board concluding that the Darlington Refurbishment was "a good idea". Without any hesitation, the Applicant agreed, and said that none of the major impacts of the Darlington Refurbishment should be included in rates if the Board was not giving a green light to the project[136].

4.11.4 In the end, SEC concluded in that proceeding that the CWIP proposal was at least in part a step in a strategy to get indirect approval of the Darlington Refurbishment project by the Board.

4.11.5 There was a lot of confusion in this current proceeding as to exactly what OPG was asking of the Board with respect to commercial and contracting strategies. That was eventually clarified during the oral hearing, when, in response to cross-examination by SEC, the Applicant made clear the components of their commercial and contracting strategies that they want the Board to approve[137]:

(a) Use of the multi-prime contractor model (with OPG acting as the general contractor, and a small number of prime contractors reporting to OPG project management oversight);

(b) Segmentation of the project into five major work "packages";

[136] See the SEC Final Argument, p. 29-31, where the exchange at Tr. 13:87-8 is quoted.
[137] Tr. 16:3-5.

(c) Use of the Engineer-Procure-Construct (EPC) model as the default structure for the external contracts, unless it is unavailable at a reasonable cost for particular components:

(d) The approach to the allocation of risk, including the level of owner oversight required given the risk allocations.

(e) Application of the above four principles to the work done to date.

4.11.6 Those five "approvals" can be translated, cynically, into the following:

(a) No-one should be allowed to say, later, that in light of OPG's poor history managing very large projects, it was unwise for OPG to take on the general contractor role in this, one of their largest projects ever.

(b) Even if OPG ends up giving multiple work packages to the same prime, this still amounts to a strategy of project diversification.

(c) Since EPC is only the default, any mix of contract structures will comply with the third principle, and therefore any mix would be considered "approved" by the Board later.

(d) As a practical matter, all significant risks will be allocated to OPG and borne by the ratepayers.

(e) The Board should confirm that the reason for the cost overruns and delays to date is that these principles were not followed, but OPG is changing their approach for the future.

4.11.7 What OPG has in fact said is that these four components of their strategies are essentially the only choices realistically available to them. They can't find a general contractor to take this on at a reasonable cost. Thus, they have to divide up the project between primes. The contractors will insist on control of the engineering and design, or they will have someone to blame for overruns. The contractors will not accept any material risks, so OPG and hence the ratepayers really are the only ones that can take the risks.

4.11.8 So what is the Board to say? "We agree you don't have any choice"? "We agree that, if the cost comes in over budget (what a shock), that is a risk the Board, on behalf of the ratepayers, took on willingly"?

4.11.9 The whole point here, in our submission, is to prevent any criticism of OPG's performance later by asking the Board to "approve" things now, even though those things are ones that OPG says are essentially inevitable. OPG wants to be able to say later: "Not our fault. We just did what you told us to do."

4.11.10 In our submission, this is not an appropriate role for the Board. Even if it were reasonable for the Board, in a few weeks, to make a thoughtful judgment on the key commercial and contracting strategies that took OPG decades to reach, and for the Board to do that without any independent expert analysis or advice, this is not what the Board does.

4.11.11 Of course, the OPG strategy here could be more indirect than that. This could be all about hindsight.

4.11.12 From the point of view of downside protection, OPG knows that in some future proceeding they will ask the Board to approve inclusion of $12 billion or more in rate base for the refurbished Darlington. The spending will have been done, and the Board will be determining whether that spending, and the resulting cost, was prudent. The Board will be expected to apply the rule that the spending is rebuttably presumed to be prudent, unless, based on the information available to the company at the time decisions were made, without using hindsight, the spending was imprudent.

4.11.13 Having now provided a detailed, almost verbose, description of their approach and strategy, and all of the considerations that have gone into selecting that strategy, OPG may have in fact bought insurance. Unless the Board says that they have made the wrong decisions today, OPG may be in a position to say, in that future proceeding, that the Board knew everything they knew, and didn't raise any red flags. Therefore, the Board will not be in a position to find that any part of the eventual cost was imprudent.

4.11.14 SEC believes that the public discussion of how OPG plans to spend $12 billion of the ratepayers' money was a useful exercise. The Board had at least a partial look inside the project, warts and all, and that look probably benefited both the Board and the Applicant.

4.11.15 But in the end, management has to manage, and the regulator has to regulate. In our submission, the Board should remain focused on its key role, setting rates. When the refurbished Darlington is in-service, and the amount and timing has to be reviewed, there will be an excellent record in EB-2013-0321 to assist that Board panel. Further approvals by this Board panel are neither necessary nor desirable.

4.12 ***Alignment with Long Term Energy Plan***

No submissions.

5 PRODUCTION FORECASTS

5.1 *Regulated Hydroelectric Production Forecast*

No submissions.

5.2 *Surplus Baseload Generation*

5.2.1 We have had an opportunity to review the submissions of Board Staff on this issue[138]. We agree with both their analysis, and their conclusion.

5.3 *Current Hydroelectric Incentive Mechanism*

5.3.1 See our submissions with respect to Issue 5.4.

5.4 *Proposed New Hydroelectric Incentive Mechanism*

5.4.1 We have had an opportunity to review the submissions of Board Staff on this issue[139]. We agree with both their analysis, and their conclusion.

5.5 *Nuclear Production Forecast*

5.5.1 We have had an opportunity to review the submissions of Board Staff on this issue[140]. We agree with both their analysis, and their conclusion.

[138] Staff Submission, p. 39-40.
[139] Staff Submission, p. 44-50.
[140] Staff Submission, p. 51-56.

6 OPERATING COSTS

Regulated Hydroelectric

6.1 *OM&A Budget – Regulated Hydroelectric*

6.1.1 SEC submits that OPG's hydroelectric OM&A is not reasonable and should be reduced. As the evidence shows, in each year since 2010, OPG has underspent compared to its budgeted or forecast amount. Even if the Board looks at just the Base and Project OM&A categories, which Mr. Mazza stated were his responsibility (as compared to corporate and centrally held costs)[141], OPG continually over-forecasts its hydroelectric operating costs.

Hydroelectric OM&A ($M)					
	2010	**2011**	**2012**	**2013**	***Average***
Prev. Regulated Base + Project OM&A Plan	67.1	78.4	73.8	84.9	*76.1*
Prev. Regulated Base + Project OM&A Actual	64.8	56.7	73.8	76.3	*67.9*
Newly Regulated Base + Project OM&A Plan	130.8	131	129.4	129.2	*130.1*
Newly Regulated Base + Project OM&A Actual	139.8	127.6	123.2	126.6	*129.3*
Total Plan	197.9	209.4	203.2	214.1	*206.2*
Total Actual	204.6	184.3	197	202.9	*197.2*
Actual/Plan (%)	***103.4%***	***88.0%***	***96.9%***	***94.8%***	***95.7%***
Source: L/6.1/Sch 4 CCC-17,18, L/1.0/Sch 1 Staff-002/Attach 1/Table 16,17					

6.1.2 The evidence in fact shows that OPG is on track to underspend again in 2014.[142] While OPG attributes the underspending between 2010 and 2013 primarily to unfilled vacancies, less overtime than expected, and the use of temporary staff to fill positions, it admits it will not fill all the current vacancies in 2014.[143] It should be recognized that the filling of vacancies, and the corresponding reduction in use of temporary staff and unfilled vacancies, comes at a significant cost to ratepayers, with no corresponding benefit. There is no indication that OPG's hydroelectric facilities had any reliability or operational setback because regular employees were not being utilized. Mr. Mazza was only able to point to some reprioritization of certain projects but that "it's not a backlog".[144] Further, the employees who will be filling these vacancies are not experienced hydroelectric operators, but are

[141] Tr. 4:155.
[142] J3.13.
[143] Tr. 3:166-67. Tr. 4:72.
[144] Tr. 3:161.

primarily employees who have been moved from the now closed unregulated thermal facilities and retrained.[145]

6.1.3 SEC submits that in recognition of this, the Board should reduce OPG's hydroelectric Base and Project OM&A by reducing its requested amount by 4.3% a year, a reduction of $9.7 million in 2014 and $10.0 million in 2015, which would reflect OPG's historical percentage of actual versus planned hydroelectric OM&A spending.

6.2 ***Benchmarking – Regulated Hydroelectric***

6.2.1 SEC has concerns about the adequacy of OPG's hydroelectric benchmarking. While perfect should not be the enemy of the good, it has become apparent that OPG's hydroelectric benchmarking is less useful, and encompasses fewer cost categories, than had previously been understood.

6.2.2 OPG benchmarks its hydroelectric OM&A costs against two sources of information, the Electric Cost Utility Group ("EUCG") and Navigant. The problems with the benchmarking are:

(a) they exclude a significant amount of OPG's hydroelectric costs; and

(b) neither benchmarking exercise is independent.

6.2.3 ***Costs Excluded.*** Both EUCG and Navigant exclude a number of costs that make up a significant portion of OPG's hydroelectric OM&A expenses. While some of these cost items are correctly treated as externally imposed, such as the Gross Revenue Charge and water usage fees, others are not.[146] As an example, in using the Navigant data, OPG does not include environmental and regulatory costs. Both Navigant and EUCG do not include corporate or centrally held costs.[147] These are costs that are within OPG's control.[148] Centrally held costs alone make up about 18% of OPG's hydroelectric OM&A costs.

6.2.4 Further, OPG has discretion in what it includes and what it does not include in cost categories. This is not to suggest that OPG is intentionally excluding costs; it is simply a lack of rigour to the benchmarking exercise.[149] While the data may go through a review process, it is not done through an independent process to ensure accuracy and uniformity.

6.2.5 While OPG may be in the top first or second quartile for a number of its

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[145] Tr. 3:159.60
[146] JT1.10.
[147] Tr. 4:7-9.
[148] Tr. 4:10.
[149] Tr. 5:5-6.

hydroelectric facilities[150], considering the significant costs that OPG has that are excluded, the results should be of little comfort to the Board. This is especially problematic, since OPG's significant labour and pension costs are excluded corporate and centrally held costs. There is nothing on the record which would allow parties and the Board to assess OPG's performance of its hydroelectric facilities on a fully allocated basis.[151]

6.2.6 ***Lack of Independence.*** As discussed previously, the lack of independence of OPG's hydroelectric benchmarking creates significant doubts about its usefulness. Mr. Mazza stated that most utilities they benchmark against use the same process as OPG.[152] While SEC has no reason to disagree with that observation, it is important to note that most of the comparator hydroelectric facilities are not rate regulated. Independent benchmarking to help the Board determine the reasonableness of costs (as opposed to as a management tool), may not be as significant to other facilities as it should be for OPG.

6.2.7 While OPG states that it has no plans to undertake independent benchmarking of its hydroelectric facilities, it recognizes that it could be done.[153] As the Board plans to implement some type of incentive regulation mechanism on OPG's hydroelectric facilities, it is important that the basis of it is a rigorous empirical benchmark. Currently, OPG has not done that. The Board should order OPG to conduct a fully independent, and fully allocated, OM&A benchmarking exercise as soon as practical, so that it is ready for use by the Board and parties to determine the appropriate structure of OPG's hydroelectric incentive regulation framework.

6.2.8 ***OPG Is Not Using Benchmarking as a Management Tool.*** SEC is concerned that OPG's use of benchmarking information seems to be primarily for regulatory purposes, i.e. to justify its OM&A costs before the Board. It does not appear to be a core part of how it operates and budgets its hydroelectric facilities.

(a) The EUCG and Navigant results are not a prominent part of the business planning process. There is no reference in either OPG's 2014-16 Business Plan[154] or Hydro Thermal Operations 2014-2016 Business Plan.[155]

(b) Mr. Mazza testified during cross-examination that lately benchmarking results have not been provided to OPG's Board of Directors.[156]

(c) Benchmarking also does not make up any part of the incentive payment for

[150] L/6.2/Sch 2-AMPCO-36.
[151] Tr. 4:155.
[152] Tr. 4:3.
[153] Tr. 4:152.
[154] N1/1/1/Attachment 5
[155] N/1/1/Attachment 6
[156] Tr. 4:55.

hydroelectric management.[157]

(d) When asked about what changes OPG has made to its operation as a result of its benchmarking activities, Mr. Mazza could not point to anything recently, only changes made at least a decade ago.[158]

6.2.9 Benchmarking should not simply be used as a tool to justify costs before the Board. It should be used as a management tool, to ensure that OPG is operating its facilities as efficiently as it should be. In doing so, the costs being sought from ratepayers will be impacted, as OPG's actual costs will decrease, and its production may increase.

Nuclear

6.3 ***OM&A Budget - Nuclear***

6.3.1 We have had an opportunity to review the submissions of Board Staff on this issue[159]. We have provided our comments with respect to compensation, and the Business Transformation Initiative, separately in these submissions. Subject to those specific comments, we agree with the Board Staff analysis. We also agree with their conclusions, but we note that our proposed reductions in compensation costs would subsume the Nuclear OM&A costs being proposed by Staff.

6.4 ***Benchmarking - Nuclear***

6.4.1 We have reviewed the submissions of Board Staff on this issue[160]. We have also had an opportunity to review, in draft form, the very useful submissions of CME on this issue.

6.4.2 SEC believes that OPG has not yet internalized the importance of strong benchmarking in its nuclear costs. We also believe that the Business Transformation initiative, which has moved nuclear costs around in ways that are not 100% transparent, has made nuclear benchmarking somewhat more difficult, particularly with respect to comparisons over time.

6.4.3 Subject to those general concerns, SEC commends the Board Staff and CME analyses to the Board, and has no further submissions to add.

[157] Tr. 4:55.
[158] Tr. 4:53-54. Tr:4:153-154
[159] Staff Submissions, p. 61-64.
[160] Staff Submissions, p. 64-72.

6.5 ***Nuclear Fuel Costs***

No submissions.

6.6 ***Pickering Continued Operations***

No submissions.

6.7 ***OM&A Budget – Darlington Refurbishment***

No submissions.

6.8 ***Human Resources Related Costs***

Compensation (excl. Pension and OPEBs)

6.8.1 In this part of our Final Argument, we will consider two key aspects of human resources costs: FTE/headcount data and increases ("How many people?"), and benchmarking of compensation levels ("How much should they be paid?).

6.8.2 ***Overview.*** OPG's compensation costs and its related effects on fleet performance have been a long-standing concern of SEC and the Board.

6.8.3 The Board raised significant concerns in OPG's first payment amount proceeding (EB-2007-0905) where it made a $35 disallowance regarding OM&A costs related to Pickering A and required the filing of updated benchmarking studies in its next payment amounts application to re-examine the issue of staffing and compensation costs[161].

6.8.4 In OPG's subsequent payment amounts proceeding (EB-2010-0008), the Board was once again not satisfied that OPG's compensation costs were reasonable. After making a number of findings regarding OPG's inappropriate compensation benchmarking and staffing levels, it reduced the amount to be recovered from ratepayers over the two year test period by $145 million.[162] It also ordered OPG to conduct an independent compensation study to be filed in its next application as it found that the benchmarking analysis filed was inadequate.[163]

6.8.5 While OPG ultimately was able to reduce its compensation costs by $145 million, it appealed the Board's decision on an "issue of principle".[164] The Board's decision on the disallowance was upheld by the Divisional Court, but overturned by the Court

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162 EB-2010-0008 Decision, p. 87.
163 EB-2010-0008 Decision, p. 87.
164 Tr. 3:128.

of Appeal. The case has been granted leave and will be heard by the Supreme Court of Canada in December.

6.8.6 ***Staffing.*** OPG has made some progress regarding staffing levels. Its Business Transformation initiative is aimed at reducing headcount by 2000 employees by 2015, although the extent of the reductions is misleading for the purposes of this application since only 1300 of those employees come from the regulated operations. A disproportionate amount of the reductions emanate from OPG's unregulated operations due to the closing of its Thermal facilities, which was a government policy decision and not a OPG management initiative.[165]

6.8.7 Even with a planned reduction of 1300 regulated positions by the end of the test period, there is more that must be done. SEC has concerns with the following specific areas.

(a) ***Nuclear.*** After two proceedings in which OPG had studies showing OPG was overstaffed against benchmarking for its nuclear facilities, in EB-2010-0008 the Board directed OPG to conduct an independent nuclear staffing benchmarking survey. OPG retained Goodnight Consulting, which provided a survey in 2011 which was then updated in February 2013. The survey showed that OPG is making limited progress in reducing its overstaffing, as demonstrated by OPG's performance against the benchmarking in 2011, then again in the 2013 update. The results of the Goodnight Study are that OPG is particularly overstaffed in supporting functions. It is expected that the overstaffing will continue through the Test Period, even with Business Transformation.

(b) ***Human Resources Support .*** See section 6.10.6.

(c) ***Management Positions.*** While OPG has reduced executive positions, the number of management positions (as distinguished from OPG's use of the term management to include all non-unionized positions) will actually increase by the end of the test period. While the total number in 2014 is lower than 2013, the number rises again in 2015 above 2013 levels.[166] This is surprising, considering the criticisms made by the Board in the previous proceeding, and by the Auditor General, on this very issue.[167]

During the hearing, there was significant uncertainty about how OPG manages and plans its management and executive staffing levels. When originally asked by Board Staff during the hearing why OPG was unable to provide forecasts of

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[165] Only 65% of the Business Transformation headcount reductions are for regulated operations but over 80% (as of 2010 before the reductions began) employees are from the regulated operations. (See Tr. 9:27-28).
[166] J10.4.
[167] KT2.4 -Auditor General Report, p. 159.

management positions for the test year, OPG witnesses confirmed statements made at the technical conferences that "for business planning purposes, we don't break it down to that level". Yet, when pushed during the cross-examination OPG seemed to have changed their position, and were able to provide the numbers in an Undertaking.[168] This inconsistency is troubling, as it shows at the very least a lack of coordination between the individuals responsible for human resources, Business Transformation, and OPG's overall business planning process.

Also concerning to SEC is the Auditor General's findings that that there were 40 management employees at the vice-president and director level in 2012 that had no job title or job description, At the hearing, OPG's response to questions about the findings was that the accountabilities for those positions would be set by the direct supervisors. SEC submits that this raises concerns that these positions may not have been needed, or at the very least, the tasks they undertook did not need to be done by an executive.

6.8.8 ***Compensation.*** While OPG has made some gains in reducing its staffing levels, the same cannot be said regarding compensation levels. With 7,958 of its employees on Ontario's Public Sector Salary Disclosure List in 2013[169], its compensation levels in most instances benchmarked significantly above the 50th percentile. Serious oversight issues have been raised by the 2012 Auditor General's Annual Report. However, OPG still believes its "compensation is appropriate".[170] SEC disagrees[171]. OPG's compensation levels still remain unreasonable. In recognition of this, the full amount sought in the Application should not be recoverable from ratepayers.

6.8.9 A majority of OPG's proposed compensation costs relate to amounts it must pay its unionized workforce (PWU and the Society) as required by collective agreements. The Board is not privy the negotiations between parties, nor are ratepayers. While OPG states that it represents the interest of ratepayers in negotiations[172], they neither have the mandate to do so, nor can that be reconciled with its overarching duty to the its shareholder and itself as set out in the Memorandum of Agreement[173], or under corporate and fiduciary legal principles.

6.8.10 While OPG on one hand acknowledges that it should not pay more than the market rate for labour[174], it has also taken the view that the results of its collective

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[168] J10.3.
[169] J3.7.
[170] Tr. 9:32.
[171] And apparently, so does everyone else.
[172] Tr. 8:64.
[173] A1/4/1/Attachment 2. "OPG will operate as a commercial enterprise with an independent Board of Directors, which will at all times exercise its fiduciary responsibility and a duty of care to act in the best interests of OPG."
[174] Tr. 8:42.

agreements are the same thing as a reasonable result for ratepayers. This is even true, they say, if OPG agrees to a collective agreement that it knows is not reasonable:

> *"MR. MILLAR: What happens if you're unable to keep compensation costs down? I shouldn't say keep them down. Imagine, as a hypothetical, you failed in your negotiations and you paid more than you had to for labour. What would the repercussions of that be?*
> *MR. FITZSIMMONS: Those costs would have to be passed on to the ratepayers."*[175]

6.8.11 In assessing OPG's compensation costs, the Board must look at the results of the negotiations. OPG itself agrees with this view.[176] Unlike the situation when assessing other types of contracts, the back and forth negotiating of the collective agreement is covered by settlement privilege.[177] This does not allow parties and the Board to inquire about the specific details of individual offers and counter-offers. Even if parties could do so, as Dr. Chaykowski observed, it is very hard to know ex-post what would have happened if different positions were taken. There is no way to know what the parties' breaking points would be, or whether there would be a strike or lockout, or what measures, if any, the government may take because of the public interest nature of electricity generation.[178]

6.8.12 OPG stated that in its last round of negotiations with the PWU, it was under direction from the province (its sole shareholder), to reach a "net zero result".[179] This was a government wide mandate that was not specific to OPG.[180] The government's mandate did not take into account past Board decisions on compensation and the effect of OPG's compensation activities to ratepayers. It simply provided the same instructions that it provided to other departments, agencies and other entities over which it has authority. With the exception of Hydro One, the OPA, and IESO, they are not rate regulated.

6.8.13 SEC submits that what the Board must do, in fulfilling its statutory mandate, is to act as the market proxy. It must ensure that ratepayers do not pay more than the hypothetical competitive market would bear. To do that, it must compare OPG's compensation costs against external benchmarks to assess reasonableness.[181]

6.8.14 ***Market Compensation Levels.*** In response to the Board's direction from EB-2010-

[175] Tr. 8:53.
[176] Tr. 8:88.
[177] Tr. 8:88.
[178] Tr. 9:78-80.
[179] Tr. 9:62.
[180] Tr. 9:63.
[181] Even under the most generous reading of the Ontario Court of Appeal decision (*Power Workers Union v. Ontario Energy Board, 2013 ONCA 359*) , the Court did confirm that Board must act as a market proxy (see para 38).

0008, OPG retained and filed an independent compensation benchmarking report conducted by Aon Hewitt.[182] The report reviewed compensation (both base and total cash) for management (non-unionized), the PWU and the Society positions, and compared them to three categories of comparators organizations.

6.8.15 The report shows that on both a base salary and total cash compensation basis, the PWU is paid significantly more than the 50th percentile in all three categories of comparator positions. Considering that PWU members make up over half of OPG's employees, the impact on total compensation costs is significant. Also troublingly, the report shows that for OPG positions that are not specific to power generation, nuclear, or electric utilities, the PWU and Society employees are paid significantly higher than the 50th percentile. These positions in areas such as administration, finance, information technology, and human resources, are in less demand than operational positions. One would expect that the average salaries would be closer to the 50th percentile, not further away.[183]

6.8.16 The Board has been clear that it expects OPG to benchmark its compensation levels against the 50th percentile. Since OPG did not utilize the Tower's Watson (formerly Towers Perrin) data as they had done in the previous case, it is not possible to determine what type, if any, progress has been made bringing compensation closer to the 50th percentile.[184]

6.8.17 What the data does show is that OPG compensation costs, at least with respect to the PWU, are not reasonable. SEC submits that the Board should disallow PWU compensation costs in excess of the 50th percentile. OPG estimates that amount to be $96 million in 2014 and $94 million in 2015.[185]

6.8.18 Further evidence of OPG's excessive compensation levels are comparisons with similar positions in the Ontario Public Service. According to the Auditor General's Report shows that the <u>average</u> total earnings of OPG for its sample of positions are significantly higher than the <u>maximum</u> total earnings at the Ontario Public Service. For an organization that in the past has stated that it is moving towards "a more public-sector employment situation", OPG has not demonstrated that.[186] The Aon Hewitt study does not include similar Ontario Public Service positions. OPG could have easily asked for that information to be provided from its shareholder, but evidently did not think it would be important. SEC submits this was likely because it would have shown OPG compensation levels even further from the 50th

[182] F5/4/1.
[183] *Power in Motion: 2011 Labour Market Information Study (2012 Update)* sets out the demand in the power sector for positions is primarily in the engineering and operations are, not support services. (see L/6.8/17-SEC-110/Attachment 2)
[184] Tr. 8.p.192.
[185] J9.11.
[186] KT2.4 - Auditor General Report, p. 159. Tr. 9:56-57.

percentile.[187]

6.8.19 In the EB-2010-0008 Decision the Board recognized the moving to the 50th percentile would take time because of OPG's collective agreements with its union.[188] OPG has entered into new agreements with both the PWU and the Society since that Board decision. The evidence was clear that OPG did not even rely on any wage benchmarking information when it entered into agreements with the PWU.[189] Nor is there any reference in the interest arbitration award with the Society that benchmarking information was presented by OPG in that hearing.[190] OPG had the Towers Watson information that was before the Board in the EB-2010-0008 proceeding, as well as updated information based on Towers Watson data to which it subscribes.

6.8.20 In addition, knowing full well what the Board had expected OPG to do as a result of its EB-2010-0008 Decision, it was reasonable for OPG to have undertaken a more comprehensive compensation benchmarking study (e.g. the Aon Hewitt Study) at the time it entered into collective bargaining. It ultimately chose not to use the information in negotiations or even internally as a "reasonableness check" in entering into the collective agreements that it did.

6.8.21 Incredibly, OPG spent considerable funds appealing the compensation component of the previous decision on the basis that in its view the Board improperly used 'hindsight' by relying compensation benchmarking information from a period after it entered into its last collective agreement. Yet, when presented with a subsequent round of collective bargaining, it did not undertake <u>any</u> benchmarking activities.

6.8.22 OPG believes that the proper compensation comparators are not the broader group of organizations in the Aon Hewitt study, but only successor Ontario Hydro companies, and specifically Bruce Power and Hydro One. SEC notes that the comparisons OPG has made to Bruce Power are significantly flawed.[191] As was revealed during the oral hearing, the pay band comparison in its evidence between OPG and Bruce Power is not accurate. A significant number of OPG employees are paid above the pay band. While SEC does not dispute OPG's explanation of this, it does dispute the relevance. Just because OPG has grandfathered in certain employees in its collective agreement at above-maximum pay band, does not detract from the fact that the OPG's own comparison between itself and Bruce Power is inaccurate and that the <u>actual</u> pay gap that may not exist at all. While OPG's evidence that the over-band employees will constitute a negligible amount by 2020, there is still a significant number of these employees through the test

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[187] KT2.4 - Auditor General Report, p. 166. Tr. 9:61.
[188] EB-2010-0008 Decision, p. 87.
[189] L/6.8/1-Staff 102.
[190] L/6.8/17 SEC-110.
[191] F4/3/1/Table 2 (PWU Positions) and F4/3/1/Table 4 (Society Positions).

period.[192]

6.8.23 ***Lack of Oversight and Accountability.*** OPG oversight of its human resources activities is unacceptable. As detailed in part in the Auditor General's Report, OPG has considerable gaps in its oversight and accountability in how it pays compensation to its employees. SEC submits ratepayers should not have to bear the cost of compensation costs that can reasonable attributed to any of these accountability gaps and lack of internal controls:

(a) ***Performance Evaluations.*** SEC submits that OPG's oversight and management of its performance evaluation process is inadequate, likely leading to unreasonable increases in cost to ratepayers. As the Auditor General found that in a sample of 15 employees, only 2 of 30 performance evaluations were completed.[193] OPG readily admitted at the hearing that it has no formal requirement for job evaluation.[194] Its current system with its unionized employees is that performance is assumed to be acceptable for the purposes of a scheduled wage increase "unless there is an intervention to the contrary".[195] This is especially problematic considering that the Auditor General found that employees felt that there was not appropriate performance management in place for unionized employees and there was a "tendency to avoid dealing with poor performance". It is reasonable to assume that at least some individuals received increases in wages to which they would not have been entitled if proper performance evaluations had been undertaken.

(b) ***Overtime Management.*** OPG's quantum of overtime has been an issue before the Board in the past, and confirmed as a concern in a number of different studies.[196] SEC still is unable to understand how OPG overtime (specifically as it related to nuclear operations) compares to its peers, since the Goodnight Study did not include outage overtime. From OPG's evidence, outage overtime levels consist of roughly half of its total overtime costs.[197]

Also of concern is OPG's overtime policy and internal controls. In the Auditor General's Report, it found that while OPG's policy required that overtime had to be pre-approved by a supervisor, a review of sample employees found that 20% did not have any supporting documentation.[198] Further, a sample of respondents to its survey found that many "felt that the most common contributor to inappropriate and inefficient uses of overtime was poor planning

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[192] See J8.1
[193] KT2.4 - Auditor General Report, p. 168
[194] Tr. 9:126. Tr. 8:127.
[195] Tr. 8:126.
[196] Navigant (2006), ScottMadden (2009) and Goodnight (2011 and 2013)
[197] The Goodnight Study states OPG's 2010-2013 nuclear operation overtime levels are between 6-7%. In Undertaking J11.2, OPG provide an overtime analysis including outages, which average 12% a year.
[198] KT2.4 -Auditor General Report, p. 174.

and scheduling." Respondent's further stated that "unionized staff sometimes treated overtime as an avenue to increase their pay."[199] This lack of oversight, and the belief that at least some employees are using overtime as a way to increase their pay in ways they couldn't otherwise, is inappropriate. SEC submits that, as OPG readily admitted during the hearing, this is a consequence of the fact that OPG has no specific criteria for overtime, or written guidelines to help line managers. Overtime is simply a budgeted amount.[200]

(c) ***Incentive Payments.*** While SEC supports incentive payments as an important way for utilities to properly motivate their employees, there are some significant concerns with respect to OPG Annual Incentive Plan payments for non-union employees. The Auditor General found that the distribution of higher Annual Incentive Plan scores was skewed towards executive and senior management staff.[201] While OPG's more capable employees hold these positions, one would expect that their performance targets and expectations would be correspondingly adjusted, so that there is not such a large disparity between the distributions of incentive score. This is especially important considering that incentive payments are as high as 30% of base salary for directors, and can be over two-thirds of base salary for senior executives.[202]

With all of the issues raised in this application and in previous proceedings, nobody could honestly say that OPG is in the midst of a period of incredible corporate success. Yet, over 60% of its executives and senior management between 2010-2012 received Annual Incentive Plan scores of 3 or 4 (0-4 scale).[203] SEC submits this is an indication that OPG performance targets are set too low for executives and senior management.

6.8.24 ***Summary.*** SEC submits the Board should reduce OPG's compensation (staffing and compensation levels) costs by $100M for each of 2014 and 2015. This amount reflects moving PWU compensation levels to the 50th percentile, further staffing level reductions, as well as an allowance to take into account amounts imbedded in OPG's forecasts arising out of oversight and accountability issues. Without significant reductions in compensation costs, OPG will have succeeded in passing along to ratepayers an unreasonable level of costs. OPG's forecast costs are simply imprudent, and do not come close to reflecting a reasonable level of spending.

Pensions and Other Post-Employment Benefits

6.8.25 The biggest single expense impacting the $2.2 billion deficiency is the increase in pension and other post-employment benefit costs (OPEBs), driving a little over

[199] KT2.4 -Auditor General Report, p. 174.
[200] Tr. 11, 28-29. J11.3.
[201] KT2.4 - Auditor General Report, p. 167
[202] KT2.4 -Auditor General Report, p. 167 – Figure 9
[203] KT2.4 -Auditor General Report, p.167 – Figure 10

$500 million of the deficiency[204] for the Nuclear and Previously Regulated Hydroelectric facilities (plus any impact on Newly Regulated).

6.8.26 Board Staff has provided a detailed analysis of the impact of pension and OPEBs on revenue requirement[205], which allows us to provide our analysis in more summary form. In general, SEC supports the analysis provided by Board Staff.

6.8.27 In this section of our Final Argument, we will look at two aspects of pension/OPEBs: the underlying problems with the OPG plans, and the choice of cash vs. accrual method of recovery from ratepayers.

6.8.28 ***Underlying Problems with the Benefits Plans.*** It is now well known that public sector pension plans, not just in Ontario, but across Canada, are facing difficult challenges if they are to remain sustainable. New Brunswick has already tackled the issue[206], but we can all see on the TV news the violent controversy in Quebec as that province seeks to do the same.

6.8.29 In Ontario, the government announced in the 2013 provincial budget a review of electricity sector pensions, and charged Jim Leech, former head of the Teachers Pension Plan, as Special Advisor to carry out that review. The review[207] was tabled with the government March 18, 2014, prior to the hearing in this matter, was not made public, and made available to the Board and the parties in this proceeding, until August 1, 2014.

6.8.30 The Leech Report, which looked at the pension plans of OPG, Hydro One, IESO, and the Electrical Safety Authority, all successors of Ontario Hydro. The Report reaches the following conclusions, among others[208]:

> *"- The four pension plans are relatively generous and **very costly to employers**.*

- *None of the pension plans are currently stable – nor do they have the ability/flexibility to handle any adversity as the parties do not share risks and the benefits are fully guaranteed regardless of the investment performance of the plans.*

- *Exposure of regulators, ratepayers and customers to **open-ended and volatile pension costs** needs to be minimized.*

- *Collective bargaining process, on its own, is not an optimal process to*

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[204] Tr. 11:123.
[205] Staff submissions, pp. 87-110.
[206] K8.1, p. 122.
[207] "Report on the Sustainability of Electricity Sector Pension Plans", March 18, 2014, Jim Leech, Special Advisor.
[208] Op. cit., p. 24.

ensure that the pension plans are sustainable and affordable on an ongoing basis." [emphasis added]

6.8.31 The Special Advisor's take on the plans is well described in the following quote from the Report[209]:

"Compared to other public-sector pension plans, the DB plans in the electricity agencies are generous, expensive and inflexible. They generally require lower contributions from employees, while providing substantial benefits. Furthermore, electricity sector employers are responsible for a larger share of pension contributions compared to most other public-sector employers. In addition, as single-employer pension plans (SEPPs), the employers bear all risks, such as investment performance, interest rate changes and increased longevity. These risks increase both the amount and the volatility of pension costs, which is ultimately borne by ratepayers, customers and the shareholder."

6.8.32 It is expected that the Report will be a starting point for a Working Group, made up of management and union, for each of the four entities whose plans were studied[210]. Thus, it is anticipated that OPG, with PWU and the Society, will commence discussions with a view to achieving the recommendations of the Report over time.

6.8.33 In the meantime, the Special Advisor recommends that the government allow OPG solvency relief, a measure available to certain public sector plans since May 2011, and for which OPG has applied[211].

6.8.34 The troubled state of public sector pension and benefit plans in Ontario is not a new thing, and in particular has been well known to OPG for some time.

6.8.35 The best example of that is the report to the OPG Compensation and Human Resources Committee dated December 14, 2011[212]. This is a presentation, authored by Towers Watson, compensation specialists, dealing with the sustainability of the OPG pension and benefit plans.

6.8.36 The Towers Watson report concludes[213]:

"Under the status quo the threshold levels for all metrics chosen to assess sustainability are exceeded."

6.8.37 We note that the metrics "chosen" were actually chosen by OPG, not the expert

[209] Op. cit. p. 8.
[210] Op. cit. p. 31.
[211] Op. cit. p. 6.
[212] JT.2.12, Attachment 1. Also at K8.1, p. 79, and K9.2, p. 11.
[213] At p. 2.

firm[214]. In fact, the witnesses on the HR panel were not even aware of the basis of the metrics, nor did they have any understanding of how those would benchmark against other companies[215]. At least one of the metrics was selected, not on the basis that it was reasonable, but on the basis that it was equivalent to the current level of costs[216].

6.8.38 This presentation was in the possession of OPG prior to, and during, the last round of negotiations with the PWU in 2012[217]. OPG says that they tried to make headway on some of the issues raised in the report, but the union refused to even agree to a committee to discuss the issues[218].

6.8.39 One of the key components of the presentation was a list of potential changes to the plans that could help make them sustainable again[219]. After some discussion of those changes[220], SEC asked OPG to put dollar figures to those potential changes. After some resistance (because it would be a lot of work), the Board determined that it would like that information, and that was provided in J9.10.

6.8.40 It turns out that at least some of the calculations had in fact been done by Towers Watson. In aggregate, a full set of the changes would reduce pension costs alone by $118 million per year[221].

6.8.41 However, that figure is a little misleading. The calculations were based on the 2008 valuation of the pension plan (there have since been valuations as of January 1, 2011 and 2014), and on the 2010 demographics (which have since been substantially altered). In both cases, the updated information, which has increased annual pension costs, would also increase the annual savings from the potential changes to the plan.

6.8.42 We also note that the dollar figures are generally on a cash basis, rather than an accrual basis. Costs on an accrual basis are significantly higher than on a cash basis, so the $118 million number is likely very low.

6.8.43 Finally, we note that these figures are for pension, and do not appear to include the impact on OPEBs. About 40% of the pension and OPEBs total each year is for OPEBs, but it is unclear which of the changes would alter the OPEBs expense each year.

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[214] Tr. 9:140.
[215] Tr. 9:142-145.
[216] JT2.12, p. 4: Pension and Benefit expense should not exceed $50,000 per active employee in constant 2011 $.
[217] Tr. 8:151. See also Tr. 9:150.
[218] Tr. 8:153.
[219] JT2.12, p. 19.
[220] Tr. 9: 151-163.
[221] J9.10. Where changes are alternative, only one is included in the total.

6.8.44 What is clear is that there are various features of the OPG plans that, if changed, could reduce the annual cost to a more reasonable level. These facts, which were known to OPG at the time they negotiated with PWU, are also consistent with the conclusions of the Leech Report.

6.8.45 We note that there are other reports and analyses in the evidence that show the extent to which the pension and OPEBs costs of the Applicant exceed a reasonable level, and create a future problem of sustainability. However, we don't believe it is necessary to go through each of them in detail. The existence of the pension and OPEBs problem at OPG does not appear to be in dispute.

6.8.46 ***Volatility of the Accrual-Based Expense.*** It also appears to be common ground that pension and OPEBs costs, calculated using the accrual method, are highly volatile. In fact, the changes in those costs from the original filing, to the First Impact Statement, and then the Second Impact Statement, and the final numbers, are ample evidence of that.

6.8.47 Volatility is a general problem with pension and OPEBs costs. The Leech Report says[222]:

> *"Pension costs represent a significant risk to prices. It is difficult to predict pension expense as market returns shift, low interest rates continue, and mortality assumptions change. This volatility represents a price risk for customers."*

6.8.48 One thing that is clear is that volatility is less for the cash basis than the accrual basis. Cash contributions are subject to statutory and actuarial smoothing mechanisms. Accrual amounts are shifted immediately by changes in plan returns, discount rates, and mortality assumptions, among others.

6.8.49 ***Increase in 2013.*** One other fact is also worth noting. The difference between cash and accrual took a substantial jump in 2013. This can be seen, for pensions, in a table provided at page 105 of the Argument in Chief. When corrected for the error in 2015[223], the Applicant's table shows pension costs within a fairly close range, with upward and downward variations, for 2008 through 2012, but then the difference jumping in 2013, 2014 and 2015.

6.8.50 We note that the figures in the Argument in Chief are for pension costs only. In our analysis, below, we provide a chart that includes both pensions and OPEBs, and that demonstrates that the difference is much greater, and so is the jump in 2013 and beyond.

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[222] Op. cit., p. 13.
[223] Which originally comes from J13.7. See the discussion in the Staff Submissions, at p. 101.

6.8.51 ***What Should the Board Do?*** Faced with such a significant increase in costs, and for pension and benefit plans that are admittedly both unsustainable, and well in excess of market reasonableness, the Board could simply disallow a portion of the pension and benefits costs. The Applicant could incur them, but they would not be recoverable from ratepayers. If the Board reached such a conclusion, SEC would consider that a reasonable response to the situation.

6.8.52 That having been said, the Board is also aware that solving the pension and benefits problems at the Ontario Hydro successor entities, particularly OPG and Hydro One, is a policy priority of the government. The Board may well feel that it is appropriate to give the government a chance to complete the task, rather than to, in effect, force the government's hand by disallowing recovery of the unreasonable component of pension and OPEBs costs.

6.8.53 In our submission, the Board can accomplish the fair result for the ratepayers, while at the same time leaving the solution to the structural problems in the OPG plans to the government process, by mandating the cash method for rate recovery, instead of the accrual method.

6.8.54 Using the information in the evidence, SEC has prepared a comparison of Cash vs. Accrual, including both Pension and OPEBs, for the period from 2008 through 2015, as follows[224]:

Pension and OPEBs: Cash vs. Accrual Comparison

	2008	2009	2010	2011	2012	2013	2014	2015
Accrual Basis	324.8	193.3	251.3	340.6	275.7	583.3	675.8	618.1
Cash Basis	262.2	266.9	272.1	304.0	376.2	328.3	411.5	425.4
Difference	62.6	-73.6	-20.8	36.6	-100.5	255.0	264.3	192.7
Grossed-up Tax Impact	20.9	-24.5	-6.9	12.2	-33.5	85.0	88.1	64.2
Total Impact	83.5	-98.1	-27.7	48.8	-134.0	340.0	352.4	256.9

Sources:	
2008 and 2009	***EB-2010-0008, F4/2/1. Table 6, lines 5, 16 & 17***
2010, 2011, and 2012	***F4/2/1. Table 4, lines 5, 17 &18***
2014 and 2015	***J13.7, corrected by J9.6***

6.8.55 The effect of moving to the cash method (which is the method used by most utilities regulated by the Board) is to reduce the revenue requirement for the Test Period, when the grossed-up tax impacts are included, by $609.3 million.

6.8.56 OPG opposes the use of the cash method, at least in part on the basis that the Board approved the accrual method in EB-2010-0008, and rejected a proposal to move to

[224] Sources as set forth on the table.

the cash method at that time[225].

6.8.57 Aside from the fact that the Applicant has since changed its accounting framework to USGAAP, the other major change since EB-2010-0008 is the enormous difference between the cash and accrual results. When this was being considered previously, the differences were less than $100 million, and could be either way. The differences for 2014 and 2015 are three times that amount, and represent a significant portion of the deficiency.

6.8.58 The other argument proposed by the Applicant to oppose the cash method is that it doesn't allow OPG to recover the actual costs that relate to the current Test Period.

6.8.59 At best, this is unintentionally misleading. The accrual method is intended to match costs with the work being done, but it also matches costs to market volatility, and interest rate volatility, in the period immediately prior to the Test Period. The issues associated with the big jump in these costs are almost entirely the result of these factors. The costs are not going up because the employees are working harder in 2014 and 2015.

6.8.60 The cash method for pensions is also intended to recover full costs to fund the pension plan over time. That is the whole point of the rules respecting contribution minimums, and actuarial valuations, for pension plans. No-one is disadvantaged by going to the cash method. In the end, the amount available to pay pensions to employees will be exactly the same.

6.8.61 Of course, OPEBs are different, because these liabilities are, for the most part, not funded liabilities. OPG, like most other companies, including all Ontario utilities, pays these costs on an ongoing basis out of current operating cashflow.

6.8.62 What this means is that the accrual method would allow OPG to collect considerably more from ratepayers, but that money would not be used for OPEBs at all. It would simply be additional cash profits for OPG.

6.8.63 Board Staff, in the hearing and in their submissions, have explored the possibility of requiring OPG to set aside a segregated fund to cover future OPEBs[226]. OPG strongly opposes that, saying that the Board lacks jurisdiction to require such a fund.

6.8.64 In SEC's view, whether or not the Board has that jurisdiction, it clearly has the jurisdiction to determine that OPEBs will only be recoverable from ratepayers to the extent that they are used for OPEBs, either in the Test Period or through dedication of those funds to future OPEB liabilities.

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[225] AIC, p. 105.
[226] Staff Submissions, p. 92-95.

6.8.65 However, SEC's proposal for the Board to require OPG to move to the cash basis at this time is actually a more pragmatic one.

6.8.66 These costs have gone up dramatically, and there is little doubt that OPG, or the government, will have to take some action. The violence in the Quebec legislature is not an accident. As everyone seems to accept, without changes these plans are not sustainable.

6.8.67 SEC is therefore proposing that, while the government and OPG are tackling this problem, with a view to bringing these annual expenses down, the Board take a practical approach and allow the recovery of the cash component in rates in the meantime. The Applicant, and the ratepayers, are not at risk, since the ratepayers are still providing the full amount of funding needed to keep the plans fully current[227]. In the event that changes are negotiated that reduce the future trajectory of costs, the accrual amounts will drop. In that event that no changes can be made, OPG and its unions have a bigger problem, because the plans will still be unsustainable. The ratepayers can't really be expected to solve that problem with ever-increasing amounts of money.

6.8.68 SEC therefore proposes that the Board order recovery of pension and OPEBs costs on a cash basis, which would have the effect of reducing the revenue requirement by $609.3 million.

6.9 ***Allocation of Corporate Costs***

6.9.1 Board Staff has included their discussion of the Business Transformation initiative under Issue 6.9. SEC has included our discussion on that initiative under Issue 1.2, Economic and Business Assumptions.

6.10 ***Centralized Support and Administrative Costs***

6.10.1 OPG's Business Transformation initiative has moved many support functions that were originally part of the nuclear or hydroelectric business lines to the "centre" to create a more streamlined and efficient operation. SEC submits that this is a positive development, but at this time it there is very little evidence that there has been any significant overall cost savings[228].

6.10.2 For the reasons set out below, SEC believes that OPG's corporate costs are

[227] The allegation of OPG in their Argument in Chief, at page 106, that they will have to write off large amounts, perhaps $3 billion, from Other Comprehensive Income, is not helpful to the Board. It is simply a repetition of a statement, unsupported by any evidence, in J13.7, filed by the Applicant on the same day it filed the Argument in Chief. J13.7 was never tested, and no evidence has been provided to show that this $3 billion writeoff would happen. Given that the suggestion of the cash basis has been known to OPG since early on in this process, if there were any actual risk of a significant writeoff, we are confident they would have filed evidence to that effect.
[228] See SEC discussion in Section 1.2.

unreasonable, and should be reduced by $35 million for each of 2014 and 2015.

6.10.3 ***Overforecasting.*** SEC submits that OPG has over-forecast corporate costs for the Test Period. In 2013, OPG's actual corporate costs were $35.1 million[229] (or 6%) less than planned. SEC submits there is no evidence that the same (or similar) causes to under-spend, for example greater attrition than it had expected, will not continue into the Test Period, nor that the Test Period budget has been adjusted to take past over-forecasting into account.[230]

6.10.4 ***Information Technology Costs.*** OPG benchmarks its information technology costs using EUCG cost data. The last available data has OPG in the second quartile for spending per employee and third quartile for spending per GWh.[231] According to OPG's own analysis, it has made no progress on improving its information technology spending metrics since 2007.[232] A utility should be expected to improve its performance over time. In this area OPG has not done so.

6.10.5 The benchmarking analysis itself is flawed. As KMPG correctly recognized, the report is not independent, and because of that the "approach and methodology were not clearly defined and therefore not appropriate".[233] Further, KPMG noted that common industry standard comparisons were excluded from the analysis such as spending per tower or capital/operational cost distribution. OPG confirmed that EUCG does collect that data, at least for spending per tower.[234] SEC submits it should include this metric in its next information technology benchmarking analysis.

6.10.6 ***Human Resources Costs.*** OPG also benchmarks its human resources costs also using EUCG data. The same criticisms about lack of independence for its information technology benchmarking apply to its human resources benchmarking. Against other utilities that provide EUCG data, OPG ranks poorly. For 2012, in the HR costs per employee (HR expenses factor metric) OPG was in the 3rd quartile.[235] In its human resources FTEs per all FTEs ratio metric, OPG is in the bottom quartile.[236] This is indicative that OPG has an unreasonable amount of staff in its human resources (People & Culture) department, and that there is further room for efficiencies. Even the analysis that OPG has undertaken might in fact be masking what is much worse performance. KPMG noted a number of limitations in what data was collected, and added significant criticism that the peer group was not an appropriate comparator for OPG.[237]

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[229] 2013 Plan = $597.9M (F3/1/1/1), 2013 Actual = $562.8M (L/1.0/1-Staff-002/Table 24).
[230] Tr. 8:8-9.
[231] F/3/1/1, p. 6.
[232] JT 2.15, Attachment 1.
[233] K3.1 - *KPMG: Assessment of Benchmarking Reports from OPG*, p. 48.
[234] J9.3.
[235] F3/1/1, p.14.
[236] F3/1/1, p.15.
[237] K3.1 - *KPMG: Assessment of Benchmarking Reports from OPG*, p. 61-62.

Depreciation

6.11 *Depreciation Expense*

6.11.1 SEC's only specific concern on depreciation is with respect to the Niagara Tunnel Project. OPG has proposed a useful life of 90 years. SEC submits that the more appropriate useful life would be 150 years. The original two tunnels, which were completed in 1955, are expected to be in-service until 2074.[238] If those tunnels had a useful life of approximately 120 years, it is reasonable for ratepayers to expect that the Niagara Tunnel Project, which was constructed over 50 years after completion of the original two tunnels, would be constructed with superior materials and technology.

6.11.2 SEC in general also supports the submissions of Staff[239] with respect to the need for more precise information going forward.

6.12 *Depreciation Studies*

No submissions.

Other Costs

6.13 *Income and Property Taxes*

6.13.1 There are two issues in dispute under this heading:

(a) the application of the 2013 loss carry-forwards, and

(b) treatment of the deferred taxes liability for the Newly Regulated Hydroelectric.

6.13.2 ***Application of 2013 Loss Carry-forwards***. Board Staff has argued, in their Submissions[240], that the 2013 loss for income tax purposes (calculated on a regulatory basis), should be applied to reduce taxable income in the Test Period. This would reduce the 2014 taxable income by $211.4 million[241], the 2014 PILs amount by about $52.9 million, and the revenue requirement, after gross-up, by $70.5 million[242].

6.13.3 There is no doubt that the last payment amounts included an average of $76.0 million per year for PILs. Grossed up at the tax rates applicable in those years

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[238] L/6.12/Staff-106(e).
[239] Staff Submissions, p. 16-17.
[240] Staff Submissions, p. 118.
[241] J13.4, Attachment.
[242] $211.4 million*25%, divided by 0.75.

(25%), the amount paid by ratepayers in their payment amounts was $101.3 million per year.

6.13.4 There is also no doubt that OPG voluntarily elected not to seek new payment amounts for 2013, even though their previous payment amounts were based only on 2011 and 2012. One of the results of that decision was that, in 2013, OPG continued to collect $101.3 million per year from ratepayers to pay PILs.

6.13.5 What happened, in fact, is that OPG lost money on the prescribed facilities in 2013 on a regulated basis, and when that was converted into taxable income, it was a tax loss. OPG still collected the $101.3 million from ratepayers, but it didn't spend it on taxes. It kept that money.

6.13.6 OPG argues[243] that the reason they get to keep this is the "benefits follow costs" principle that applies to tax benefits. OPG argue that they actually lost money in 2013, so they get the benefit of the tax deduction that goes with that loss. The "costs" the benefits should follow, they say, are the costs of operating the prescribed facilities.

6.13.7 Board Staff, on the other hand, say that the relevant "costs" are the amounts included in rates, in this case the PILs cost included in 2013 payment amounts. Ratepayers paid that cost, so they should get the benefit of the tax loss carry-forward.

6.13.8 SEC agrees with Board Staff in the result, but we get there using a more pragmatic approach.

6.13.9 The OPG argument on this point essentially amounts to a request that the Board reward them with $101.3 million for deciding not to seek new payment amounts in 2013, while allowing their costs to increase sufficiently that they lost money.

6.13.10 The "benefits follow costs" principle was used by the Board to ensure that there was a principled way of allocating costs and benefits to regulated and unregulated periods. That is not the case here. In this case, the loss arose during a period in which OPG was collecting regulated rates from ratepayers. That is a similar situation to the electricity distributors, who do have to apply tax loss carry-forwards in one regulated year to reduce taxable income in subsequent regulated years.

6.13.11 The "benefits follow costs" principle was never intended to allow a utility to collect money from ratepayers for PILs, then keep that money for their own purposes because they were unable to operate the regulated business at a profit.

6.13.12 In SEC's view, the regulatory tax loss in 2013 should be carried forward to 2014 to

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[243] AIC, p. 118.

reduce taxable income and therefore payment amounts.

6.13.13 ***Deferred Taxes on Newly Regulated Hydroelectric Assets***. The Applicant proposes to ask ratepayers to pay, in the future, for tax costs incurred prior to the regulation of the Newly Regulated facilities. SEC disagrees with that proposal on the basis that it is:

(a) Unfair to the ratepayers, and

(b) Retroactive ratemaking.

6.13.14 The facts are as follows.

6.13.15 The Board is required by regulation to accept the balance sheet of the Newly Regulated Hydroelectric facilities as of December 31, 2013. The wording of the provision is as follows[244]:

"11. In making its first order under section 78.1 of the Act in respect of Ontario Power Generation Inc. that is effective on or after July 1, 2014, the following rules apply:

i. The order shall provide for the payment of amounts with respect to output that is generated at a generation facility referred to in paragraph 6 of section 2 during the period from July 1, 2014 to the day before the effective date of the order.

ii. The Board shall accept the values for the assets and liabilities of the generation facilities referred to in paragraph 6 of section 2 as set out in Ontario Power Generation Inc.'s most recently audited financial statements that were approved by the board of directors before the making of that order. ***This includes values relating to the income tax effects of timing differences and the revenue requirement impact of accounting and tax policy decisions reflected in those financial statements****."[emphasis added]*

6.13.16 The Applicant has filed evidence showing the amounts that it believes are included in its 2013 audited financial statements, and that must be accepted by the Board under this regulation. The most current was dated June 11, 2014[245]. The assets and liabilities listed are the following:

[244] O.Reg. 53/05, as amended. L/1/2-AMPCO-002, Attachment 1. Also included at K11.5, p. 12.
[245] A2/1/1, Attach. 6. Also found at K11.5, pp. 14-20.

As at December 31 *(millions of dollars)*	**2013**
Assets *(Note 1)*	
Property, plant and equipment in-service	**3,264**
Less: accumulated depreciation	**739**
Property, plant and equipment in-service, net	**2,525**
Construction in progress	**57**
Intangible assets in-service	**2**
Less: accumulated amortization	**2**
Intangible assets in-service, net	**-**
Development in progress	**-**
Materials and supplies:	
Short-term	**-**
Long-term	**1**
Liabilities *(Note 1)*	
Short-term debt *(Note 2)*	**-**
Long-term debt (including amount due within one year) *(Note 2)*	**621**
Pension liabilities *(Note 3)*	**194**
Other post-employment benefit liabilities (including current portion) *(Note 3)*	**149**
Long-term accrued charges	[redacted]
Deferred income taxes *(Note 4)*	**181**

6.13.17 The key figure here is the amount of $181million, listed as a liability for deferred taxes. This represents the net tax liability that has been charged as an expense prior to January 1, 2014, but has not yet actually been paid.

6.13.18 The amount of $181 million is in turn disaggregated and explained in Note 4 to the Applicant's filing. Note 4 includes the following breakdown[246]:

[246] Extraneous lines have been removed for ease of understanding. The removals have no impact on the result for the purposes of the issue in dispute. There is also a $14 million future tax saving associated with something called "Long term accrued charges", but those details are redacted in the Applicant's filing. The amount is not relevant to the future liability under discussion here.

	Accounting Basis	*Tax Basis*	*Timing Difference*	*Deferred Income Tax Liability*
Assets				
Property, plant and equipment, in-service, net	2,525	1,391	(1123)	(281)
Liabilities				
Pension liabilities	194	0	(194)	49
Other post-employment benefits (including current portion)	149	0	(149)	37
Net Assets (liabilities)				(181)

6.13.19 There are three elements to the deferred taxes total.

6.13.20 First, prior to 2014 OPG had recognized $194 million in pension expenses for the Newly Regulated facilities (on an accrual basis) that were not deductible for tax purposes. When deductible amounts eventually exceed accrued amounts in the future, it will have $194 million of extra tax deductions available that will generate $49 million of tax savings.

6.13.21 Second, OPG has recognized $149 million of OPEB expenses on an accrual basis that were not deductible for tax purposes. As with pensions, at some point well into the future deductible amounts will exceed accrual amounts (i.e. when the OPEBs liabilities are winding down, likely when OPG is no longer operating), and this $149 million extra deduction will generate $37 million in tax savings.

6.13.22 Third, on the other side of the ledger, OPG has taken $1,123 million more in tax depreciation (capital cost allowance) than it has taken for accounting purposes. When accounting depreciation starts to exceed CCA in a few years[247], there will be an incremental tax liability of $281 million.

6.13.23 There is also a $14 million future tax saving for something called "Long term accrued charges", but that amount is redacted in the Applicant's evidence on this point.

6.13.24 Because of the nature of the assets and liabilities, the future tax costs associated with the extra CCA taken are likely to arise many years before the future tax benefits associated with the pension and OPEBs liabilities.

6.13.25 OPG takes the position that the highlighted wording noted above[248] in O.Reg 53/05 requires the Board to reserve the value of those timing differences, a net of $181 million, to OPG's unregulated business, and not give the ratepayers future credit for those amounts. In fact, OPG states[249] that this was an intentional allocation of that

[247] L/6.13/1-Staff-171, p. 2.

benefit to unregulated by the government.

6.13.26 Notwithstanding the allegations of legislative intent by the Applicant, the Applicant filed no evidence from the government supporting that intention. Therefore, it is submitted, the statement by Mr. Barrett that the government was intentionally requiring the ratepayers to bear this cost has no evidentiary value, and must be ignored. The Board is required, under the normal rules of statutory interpretation, to interpret the regulation on the basis of its plain meaning.

6.13.27 The quoted statement in the regulation has two components, neither of which says that the ratepayers, once these assets are regulated, will be denied the tax deductions associated with the costs they are bearing in rates:

(a) The Board must accept *"values relating to the income tax effects of timing differences"*. This, in plain language, says that the Board cannot review the figure of $281 million future tax liability for CCA, and say that it should be a different number. It says nothing about the allocation of that liability to ratepayers or to OPG.

(b) The Board must also accept "*the revenue requirement impact of accounting and tax policy decisions reflected in those financial statements"*. This only says that, if OPG made an accounting decision, or took a filing position for tax purposes, the Board cannot reach back into the pre-2014 period and second-guess that decision. It is what it is. However, taking allowed amounts of CCA expense is neither an accounting nor a tax policy decision[250].

6.13.28 If, indeed, the government had intended to require the Board to allow OPG to collect pre-2014 tax expenses from ratepayers in 2014 and beyond, it would have been simple to say so. Nothing in the regulation, or in the surrounding documents, indicates that.

6.13.29 This leaves the Board with, in our view, a relatively simple question: Should the Board authorize OPG to collect, in the future, tax expenses that relate to the operation of the Newly Regulated facilities prior to 2014, and thus prior to regulation by the Board? That is, should the Board allow them to collect those expenses twice – once when they were incurred, and a second time when they are

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[248] See para. 6.13.15.
[249] Tr.11:149.
[250] There is an accounting policy decision that OPG took for these assets pre-regulation. At Note 4, OPG says "*OPG follows the liability method of accounting for income taxes*". The liability method expenses full taxes on an accrual basis. That contrasts with the "taxes payable method", used by the Board and applicable in this case, in which only the forecast of the actual tax bill is treated as a cost for ratemaking purposes. For the Board to accept that accounting policy decision would imply that it is obligated to accept that the taxes already expensed, under the liability method, pre-2014 must be accepted as having already been expensed. The Board would not be allowed to treat those taxes as still being payable in the future.

included in regulated rates?

6.13.30 SEC submits that, to allow OPG to collect tax expenses that arose prior to 2014 from ratepayers in subsequent periods is not only unfair to the ratepayers, but is retroactive ratemaking. It is a basic principle, which the Board has followed consistently on many occasions[251], that expenses for a past period cannot be recovered in rates in a current period, unless either rates were declared interim, or there was a deferral or variance account in place to govern those expenses. Neither is the case here.

6.13.31 SEC notes that this is not the first time this issue has come up. In EB-2010-0008, SEC filed an extensive argument, asking that the Board allow timing differences from prior to 2008 to remain available to reduce taxes after the original prescribed assets became regulated. SEC specifically asked that the "benefits follow costs" principle be applied[252].

6.13.32 The Board, in its Decision with Reasons[253], clearly and corrected characterized SEC's submissions, and had an opportunity to determine that timing differences should be for the benefit of OPG rather than the ratepayers. They did not do so. Instead, they specifically limited their conclusion to rejecting the actual calculations by SEC, not the principles being proposed. That left the issue to be determined on the basis of interpretation of the EB-2009-0038 decision, which was entirely about the treatment of tax loss carry-forwards. The issue of timing differences was not relevant.

6.13.33 In our submission, the Board has never determined that it is appropriate to allow recovery in rates of tax expenses incurred prior to regulation by the Board. Further, it is submitted that, if the government had intended to require the Board to adopt such a rule, it would have said so explicitly.

6.13.34 Finally, there is a parallel here in pension and OPEB costs that should be of concern to the Board. The audited figures for the Newly Regulated facilities as of December 31, 2013 include a liability of $194 million for pensions, and $149 million for other post-employment benefits. If the Applicant believes that the ratepayers post-2013 should be required to pay pre-2014 tax costs, does that mean that the ratepayers post-2013 should also bear this $343 million of pension and OPEB costs that have already been expensed prior to 2014?

6.13.35 The response of the Applicant on this point is not clear. In the Argument in Chief, OPG emphasizes[254] that it believes the Board must

[251] See for example, *Decision and Order* (EB-2011-0198), p. 13; *Decision and Order* (EB-2011-0176), p. 16;
[252] No submissions were made on retroactive ratemaking.
[253] At pp. 131-134.
[254] AIC, p. 103.

> *"ensure recovery of the cost impacts flowing from OPG's pension and OPRB obligations (and the funded status of the pension plan) that initially arose prior to regulation and are reflected in the financial statement liability values."*

6.13.36 This repeats, almost verbatim, the response of the Applicant in J11.7.

6.13.37 In both cases, the issue is whether the Board should make a distinction between pension and OPEB liabilities for active employees (i.e. who are providing services for the benefit of ratepayers now) and for retirees and other inactive employees.

6.13.38 There is, therefore, an obvious ambiguity as to the position of OPG with respect to pension and OPEB liabilities as of December 31, 2013. OPG seeks to have pension and OPEBs recovered in rates on an accrual basis. Does OPG also seek to have current ratepayers cover the cost of underfunding prior to 2014? Do ratepayers have to pay the current accounting costs, plus the $343 million liability that accrued when these assets were not regulated?

6.13.39 Our understanding of OPG's position is that they are not claiming this kind of double recovery, but that puts them in a bit of a consistency problem.

6.13.40 If OPG seeks to recover that $343 million from ratepayers in the future, that is clearly retroactive ratemaking, and it would be hard to argue otherwise. However, OPG must then explain why the $181 million of deferred tax liability would somehow be different.

6.13.41 Conversely, if OPG agrees that the $343 million is a past period expense, and therefore should not be recovered again from the ratepayers in the future, they would have to explain why the same principle should not apply to the $181 million in past tax expenses.

6.13.42 Further, if OPG argues that they should recover all of those liabilities from ratepayers going forward - $524 million – does that mean that the ratepayers also have to pay the $621 million in long term debt outstanding as of December 31, 2013. Is the Board required under O. Reg. 53/05 to accept the value of that liability, instead of doing its normal calculation of debt and equity relative to rate base? Ratepayers might well be willing to accept paying the $524 million of tax, pension and OPEB liabilities in the future, if their obligation to pay interest on long term debt, for rate base of more than $2.5 billion, is limited in the future to debt of $621 million.

6.13.43 Of course, SEC is not proposing that this result is sensible. What we are pointing out is that the interpretation of O. Reg. 53/05 with respect to deferred taxes that is proposed by OPG is not sustainable. Even if they were to try to stretch that "double recovery of tax costs" interpretation to add double recovery for $343 million of pension and OPEB costs as well, they would then have to apply a consistent interpretation to long term debt.

6.13.44 SEC submits that O. Reg. 53/05 cannot be interpreted as requiring, and could not have been intended to require, that the Board reverse the rule against retroactive ratemaking. If the government sought to require the Board to include pre-2014 expenses in regulated rates going forward, it would simply have said so..

6.14 *Asset Service Fees*

No submissions.

6.15 *Other Operating Costs*

No submissions

7 OTHER REVENUES

7.1 *Regulated Hydroelectric*

No submissions.

7.2 *Nuclear*

7.2.1 We have had an opportunity to review the submissions of Board Staff[255] and AMPCO on this issue.

7.2.2 It appears clear that OPG has consistently underestimated its Heavy Water Sales in past years. The question is: What is the best approach to adjusting those revenues?

7.2.3 The AMPCO submissions contain a very helpful table that shows the difference between Board-approved and Actuals for Heavy Water Sales in each of the years 2010 through 2013.

7.2.4 SEC has looked on those past examples of underestimated revenues using both the full last four years, and the more usual recent three years. The results can be characterized as follows:

(a) Using the last three years, the average of the annual Actuals is $56.9 million. If this is used as the forecast for each of 2014 and 2015, the Other Revenues would be increased by $67.1 million[256].

(b) Using the last three years, but taking the percentage of Actuals to forecast, that figure is 268.1%. Applying that to the OPG two-year forecast of $46.7 million gets a result of $125.2[257] million, and Other Revenues would be increased by $78.5 million.

(c) Using the full four years, the average of the annual Actuals is $49.4 million. If this is used as the forecast for each of 2014 and 2015, the Other Revenues would be increased by $52.1 million[258].

(d) Using the full four years, but taking the percentage of Actuals to forecast, that figure is 227.5%. Applying that to the OPG two-year forecast of $46.7 million gets a result of $106.2[259] million, and Other Revenues would be increased by

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[255] Board Staff Submissions, p. 121-122.
[256] ($56.9+$56.9)-($26.3-$20.4).
[257] ($26.3*268.1%)+($20.4*263.1*).
[258] ($49.4+$49.4)-($26.3-$20.4).
[259] ($26.3*227.5%)+($20.4*227.5*).

$59.5 million.

7.2.5 The fourth approach is essentially the same as the approach proposed by AMPCO, but on a year by year basis rather than aggregated over the two years. While SEC believes it would be equally reasonable to use a three-year calculation rather than four years, we adopt and accept the reasoning of AMPCO for the appropriate amount of the Heavy Water Sales adjustment, i.e. an increase of $59.5 million.

7.2.6 SEC accepts the other components of Nuclear Other Revenues as forecast.

7.3 ***Bruce NGS***

7.3.1 SEC has in the past expressed our concern that the inclusion of Bruce "Other Revenues" has become, in effect, a subsidy by ratepayers of the cost of Bruce generation. As HOEP becomes a less reliable designator of the "market" for generation, this problem has been exacerbated.

7.3.2 However, it also appears clear that there is nothing within the Board's jurisdiction that can be done about this. If the method by which the market price is established, or the terms of the Bruce Lease, are less than favourable to ratepayers, that is irrelevant, because the Board has no control over either of those factors.

7.3.3 Within those pre-determined parameters, SEC has no submissions with respect to the calculation of the Bruce net revenues.

7.3.4 We do have one proposal for the Board, however. In our view, it would be useful if the cost of generation from the Bruce NGS were provided to the Board on a regulatory basis (i.e., as if Bruce NGS were subject to cost of service regulation) in each OPG payment amounts application. By requiring that information, the Board could then use Bruce costs as a benchmark for OPG nuclear costs. As well, the amount of the subsidy of Bruce would be clearer, and would not necessarily be treated as a cost of the Prescribed Facilities, as it is today.

7.3.5 SEC therefore proposes that this calculation be added as a filing requirement for future OPG payment amounts proceedings.

8 NUCLEAR WASTE MANAGEMENT AND DECOMMISSIONING LIABILITIES

8.1 *Methodology*

No submissions

8.2 *Revenue Requirement Amount*

8.2.1 We have had an opportunity to review in draft form the submissions of AMPCO on this issue. AMPCO has provided an analysis of the Decommissioning Fund component of the nuclear liabilities, and the funded status of that component. Their conclusion is that the revenue requirement impact of the nuclear liabilities should be reduced by $14.1 million in 2014, and $14.4 million in 2015.

8.2.2 SEC agrees with both their analysis, and their conclusion.

9 DEFERRAL AND VARIANCE ACCOUNTS

9.1 *Nature and Type of Costs Recorded*

9.1.1 SEC has no submissions with respect to the existing balances in the deferral and variance accounts, except for the Capacity Refurbishment Variance Account.

9.1.2 ***Capacity Refurbishment Variance Account.*** SEC submits that the in-service additions claimed by OPG for the Darlington Refurbishment in 2011 through 2015 are incorrect, and this has impacts on the amounts recorded in the Capacity Refurbishment Variance Account for the period ended December 31, 2013, and may have additional impacts for the Test Period. Please see our submissions under Section 4.9 above.

9.2 *Balances for Recovery in Deferral and Variance Accounts*

9.2.1 See Section 9.1, above.

9.3 *Disposition Amounts*

9.3.1 See Section 9.1, above.

9.4 *Disposition Methodology*

No submissions.

9.5 *Continuation of Existing Deferral and Variance Accounts*

No submissions.

9.6 *Deferral of Clearances*

No submissions.

9.7 *Extension of Existing Hydroelectric Accounts to Newly Regulated*

No submissions.

9.8 *Discontinuance of the Hydroelectric Incentive Mechanism Variance Account*

9.8.1 SEC has reviewed the submissions of Board Staff on this issue[260], and agrees with their analysis and their conclusion.

[260] Staff Submissions, p. 126.

9.9 *New Accounts*

9.9.1 ***Niagara Tunnel GRC Variance Account.*** SEC agrees with Board Staff[261] that, in view of the fact that the Applicant will be applying for, and may get, a ten year GRC holiday with respect to the Niagara Tunnel, but has forecast full GRC payments in the Test Period, it would be appropriate to establish a Niagara Tunnel GRC Variance Account for the Test Period. If OPG does not have to pay this amount, it should be returned to the ratepayers.

9.9.2 ***Bruce Lease USGAAP Deferral Account***. SEC has proposed, in Section 1.3 of this Final Argument[262], the establishment of a deferral account to record the $59 million difference between the value of annual lease revenues under CGAAP and under USGAAP.

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[261] Staff Submissions, p. 128-129.
[262] See para. 1.3.5.

10 REPORTING AND RECORD KEEPING REQUIREMENTS

10.1 *General*

No additional submissions.

11 METHODOLOGIES FOR SETTING PAYMENT AMOUNTS

11.1 *Incentive Regulation Mechanism*

11.1.1 SEC has provided detailed submissions with respect to the application of IRM to OPG in EB-2013-0340. We will not duplicate those submissions here.

11.1.2 We do note that our submissions with respect to IRM for hydroelectric prescribed assets may have been superceded by the government's determination to add the Newly Regulated Hydroelectric facilities to the regulated side. Our basic assumption – i.e. the assets will have little capital growth, or even a declining capital base – may no longer be true. The possibility of setting a "market" price per unit of hydroelectric generation, and leaving OPG to manage within it (including using it to decide whether to build new facilities or expand existing facilities), now becomes more of a possibility[263].

11.1.3 With respect to Nuclear, the evidence in this proceeding has if anything strengthened our view that there is far too much uncertainty on the nuclear side to establish formulaic rates.

11.1.4 In both cases, however, we note an additional point that was not really addressed in EB-2012-0340. OPG has a cost control problem. Despite all of the huffing and puffing we saw in this proceeding, there has been little progress in solving that problem.

11.1.5 In our submission, until OPG has demonstrated that it has at least started down that path, then – as attractive as it may be – it may be unwise for the Board to simply set rates, and then leave OPG to fend for themselves. The ratepayers, and the Board, could find themselves in a problem of the proportion of 1999's once more, and if there was ever an entity in Ontario that is "too big to fail", that could be OPG.

11.1.6 Therefore, while SEC agrees with Board Staff[264] that the Applicant has not shown much movement on the IRM front, we continue to believe that it may be premature, at least respect to Nuclear, and probably all of the prescribed facilities, to force the issue. The short term focus today should be on improving the approach OPG is taking to cost control. Once that battle has been won, the viability of rates based on IRM principles will be more realistic.

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[263] For example, like a Feed-in-Tariff contract.
[264] Staff Submissions, p. 131.

11.2 ***Design of Payment Amounts***

11.2.1 Board Staff has proposed, in their submissions[265], that a payment amount for the Newly Regulated Hydroelectric facilities be set, for the period July 1, 2014, to December 31, 2014, at half the difference between HOEP and the new, cost-based rate.

11.2.2 With respect, SEC disagrees with this conclusion, for the reasons set forth in paragraphs 12.1.9 to 12.1.13 of this Final Argument.

11.2.3 Subject to that comment, SEC has no submissions on this issue.

[265] Staff Submissions, p. 131-132.

12 IMPLEMENTATION

12.1 *Effective Date*

12.1.1 SEC has benefitted from the thorough review of the timeline of this Application in the Board Staff Final Argument[266]. However, we ultimately come to a different conclusion with respect to the appropriate effective date(s).

12.1.2 The Application was filed on September 27, 2013. In our view, this was already at least eight months late for rates to be effective January 1, 2014. We reach that conclusion on the basis of the following:

(a) The Application in EB-2007-0905 was filed on November 30, 2007, and the Board's payment order was on December 2, 2008, 368 days later. There were no unusual delays in the proceeding. It was simply complicated, and thus took longer than the normal metric.

(b) The Application in EB-2010-0008 was filed on May 26, 2010, and the Board's payment order was on April 11, 2011, 320 days later. Again, the proceeding had no usual delays.

Without any further adjustments, this would put the payment order in this proceeding no earlier than August 12, 2014 (320 days after filing), which implies an effective date, at the earliest, of September 1, 2014.

12.1.3 However, this proceeding had further delays. It started off badly, with the initial filing having some shortcomings[267], and then a further delay arose with the filing, on December 6, 2013, of the First Impact Statement. This necessitated a new Notice, and it was thus not until December 20, 2013 that the Board could issue its first Procedural Order, and not until February 28, 2014[268] that interrogatories were due.

12.1.4 Despite the delays to that point in time, and the filing of a Second Impact Statement on May 16, 2014, the Board kept up a brisk pace throughout, so that the main hearing was able to conclude June 27, 2014. Had this been the end of it, it would have been reasonable to have submissions concluded by the end of July, and a decision as early as September. The payment order would likely have been in October, a shorter time than EB-2007-0905.

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[266] Staff Submissions, p. 134-137.
[267] An Incomplete letter was sent October 25, 2013.
[268] Already 154 days after the Application was filed, due in no part to delays on the part of the Board. This compares to EB-2010-0008, where interrogatories were due July 29, 2011, 109 days after the Application was filed.

12.1.5 However, on July 2, 2014 the Applicant filed a significant update – including important new evidence - that fundamentally changed the nature of the discussion with respect to the Darlington Refurbishment. This resulted in the need for discovery of that new evidence, and then a continuation of the hearing. In all, the Darlington Update resulted in a delay of a further month.

12.1.6 All of the delays and time issues in this proceeding were within the control of the Applicant. SEC is not faulting them for filing additional material, nor for any of the other steps. This is not about laying blame. This is about nothing more than responsibility. If the Applicant wants rates as of a specific date, it must file sufficient evidence, sufficiently in advance of that date, for the Board to satisfy the requirements of the regulatory process and order new rates by that time. The Applicant has that responsibility, and this Applicant is experienced enough to know what has to be filed, by what time, to have a reasonable chance at rates by a given date.

12.1.7 On occasion, there are delays outside the control of an applicant, and it is reasonable to adjust for those delays. That was not the case here. This proceeding had no material delays that were outside of the Applicant's control. Every step took the amount of time that any person experienced in the process could predict, given the complexity of the proceeding.

12.1.8 Therefore, SEC submits that the Board's payment order in this proceeding, with respect to Nuclear and Previously Regulated Hydroelectric, should be effective at the beginning of the month immediately following the date of that payment order.

12.1.9 ***Newly Regulated Hydroelectric***. The effective date of the payment order for Newly Regulated Hydroelectric is a special case, because on July 1, 2014 the jurisdiction to set rates for these assets passes by regulation to the Board. Under O.Reg. 53/05[269], the Board is required to set regulated rates for the Newly Regulated Hydroelectric as of July 1, 2014. This is not optional, and in our submission the Board has no authority to delay this date because of the timing of the Application and its process[270].

12.1.10 As Board Staff correctly points out[271], the regulation does not stipulate the level of rates the Board has to set, and the Board retains its normal freedom to set rates in any way it sees fit. Based on this, SEC believes that the Board has three options:

(a) Set the rate for the Newly Regulated Hydroelectric facilities based on cost of service, in the normal course, with an effective date of July 1, 2014.

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[269] O.Reg. s. 6(2)11.
[270] This is also fair. If payment amounts for the Newly Regulated alone had been sought in an application in September, they would have been within the 235 day Board metric. It is the other aspects of the Application that are the major complications.
[271] Staff Submissions, p. 133.

(b) Set the rate for the Newly Regulated Hydroelectric facilities at the HOEP rate each month, until the effective date of the main payment amounts (likely December 1, 2014), when the rate for the Newly Regulated Hydroelectric facilities would increase to the cost of service level.

(c) Combine the two approaches by way of mitigation of the rate increase, for example as proposed by Board Staff[272].

12.1.11 SEC favours the first approach, cost of service for the Newly Regulated from July 1, 2014. In our view, the intent of the regulation is that the Newly Regulated will move to a "normal" regulated rate effective July 1, 2014.

12.1.12 If the regulation had expressly provided for flexibility in determining the effective dates for new rates, SEC would have said that the effective date for all assets should be the month following the date of the payment order.

12.1.13 The regulation does not provide for this flexibility, and in our submission the Board should not try to achieve that result indirectly through either of options (b) or (c) above. The Board has a number of fundamental ratemaking principles, both for cost of service and for IRM[273]. Those principles are not consistent with using HOEP to set rates, nor with a blended rate. In our view, retaining the foundations of these principles is more important than finding an indirect way to delay the new rates for the Newly Regulated facilities.

12.1.14 ***Method of Implementation***. SEC is conscious that having new rates for Newly Regulated effective July 1, 2014, and new rates for the remaining prescribed facilities effective, say, December 1, 2014[274], may present administrative issues for OPG. However, we believe that can be resolved through the Board's normal processes. In the event that (as is likely) the new rates for the Newly Regulated exceed HOEP in that interim period, the Board can order the establishment of an Interim Revenue Shortfall rate rider, commencing December 1, 2014, to cover that differential for the five month period until the payment order is actually implemented.

[272] Staff Submissions, p. 134.
[273] In both cases based on costs, or a proxy for costs.
[274] CME has calculated, in their Final Argument, that the retroactive revenue that would be removed from the revenue requirement in this scenario would be $925 million. SEC calculates that amount – excluding the Newly Regulated Hydroelectric Facilities – at $828.3 million. That amount would, of course, change if the underlying revenue requirement for the two years is reduced by the Board, as proposed by SEC and others.

13 OTHER MATTERS

13.1 ***Costs***

13.1.1 The School Energy Coalition hereby requests that the Board order payment of our reasonably incurred costs in connection with our participation in this proceeding. It is submitted that the School Energy Coalition has participated responsibly in all aspects of the process, in a manner designed to assist the Board as efficiently as possible

All of which is respectfully submitted.

Jay Shepherd
Mark Rubenstein

Counsel for the School Energy Coalition

APPENDIX A

GEOTECHNICAL BASELINE REPORTS FOR CONSTRUCTION

SUGGESTED GUIDELINES

PREPARED BY
Technical Committee on Geotechnical Reports
of the Underground Technology Research Council

SPONSORED BY
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COMMITTEE CHAIRMAN
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collaboration should be maintained between the geotechnical and design personnel throughout this effort.

All subsequent drafts of the GBR should be advanced jointly by the design team (designer and geotechnical) so that GBR statements are consistent with the developing design, drawings, specifications and payment items. This will facilitate consistency between what is set forth in the GBR, what is contained in the drawings and specifications, and how the Contractor is to be compensated. Advancing drafts should be jointly reviewed by the design team, the Owner, and independent reviewers.

6.3 Link with Risk Registers

Whether under traditional Design-Bid-Build or DB procurement, it is recommended that the GBR be written after most of the design or reference design has been completed. During the site exploration and design phase, Risk Registers should be utilized at earlier stages of project planning, site exploration, and design to help identify key issues. As site exploration, project planning, and detailed design are advanced, certain risks will be identified that are associated with geotechnical and other subsurface conditions. It is precisely those conditions associated with the greatest perceived risks that should be addressed specifically in the GBR. However, as discussed in Chapter 11 there is no need to include the Risk Register in the GBR.

6.4 Wording Suggestions

Baselines are difficult to write without ambiguity. No one can accurately predict the nature and distribution of materials underground and how they will react to excavation. This creates a tendency to use ambiguous words to describe ranges of physical properties and behavior of the materials. The use of words such as "may," "can," "might," "up to," "could," "should," "some", "few", "ranges from ...to...," and "would" are imprecise, and must not be used in baseline statements. Better words include "is," "will," and "are". The use of such definitive terms clearly establishes the intended baselines . As discussed in Section 5.4, the use of these definitive terms must not be taken by the Owner as a warranty by the designer that the underground materials or behaviors are precisely defined. This is the goal of a well-written GBR - to avoid contractual ambiguity.

Whenever possible, baseline statements should be in terms of measurable properties or parameters that can be objectively observed and recorded during construction. The use of adverbs should be avoided. The use of adjectives such as "large," "significant," "local", "many", and "minor" should either be quantified or avoided. If qualitative terms are used, they should be standardized and defined in a summary table or a glossary. As a simple test when writing a baseline statement, ask the question: "If I encountered a site condition pertaining to this baseline would I know if it differed from the indicated conditions?" If a reasonably straightforward affirmative answer is not given, the baseline statement is not sufficiently clear.

Baseline statements regarding anticipated ground behavior should be presented in context with the use of defined means and methods of construction. The baseline statements should make it clear that the ground can (or cannot) be expected to behave differently with the use of alternative tools, methods, sequences, and equipment. In some cases, the Owner may mandate the means and methods and the baselines need to reflect this.

The presentation of baselines regarding groundwater inflows or other phenomena to be measured during performance needs to consider the methods, timing, and responsibilities for measurement in the field. These aspects must be clearly defined and expressed in the Contract Documents.

6.5 Baseline Examples

Examples of problematic and improved baseline statements are presented in Table 2 (the problematic and improved wording are underlined for ease of understanding; baseline words would not normally be underlined in the GBR).

6.6 Consistency and Compatibility

A fundamental shortcoming expressed during the industry forums, is the incompatibility between statements in the GBR and other Contract Document elements and provisions. The GBR should be consistent with and complement the other documents. The following guidelines are useful in achieving these objectives:

- The GBR may present the rationale behind the specification requirements, but should avoid stating the requirements themselves. Detailed requirements should be stated in the specifications only.

- As each baseline statement is prepared and finalized, the technical specifications and payment provisions related to that baseline statement should be reviewed for consistency and reasonableness. For example, if rates of groundwater inflow at the heading are stated as a baseline, the specifications need to define the term "heading", and where and how groundwater inflow measurements are to be taken in the field. If a TBM is involved, these descriptions must consider the physical limitations that will control where a weir or other system for measuring flows may be implemented. Payment provisions included in the Contract for handling and disposing of water must be consistent with the statements in the GBR and specifications.

- The other Contract Documents should be referenced, rather than repeated or paraphrased. If something is stated twice, even only slightly differently, an element of ambiguity is created. As with specifications, the basic rule is "Say it once, and say it well."

- The GBR should explain how the baselines relate to the data contained in the GDR. For example, if the GDR indicates that the maximum unconfined compressive strength (UCS) tested was 19,157 psi, but after discussion with the Owner, the decision was made to require the Contractor to provide for excavating 25,000 psi rock because the strongest rock is seldom found during exploration, an explanation similar