EB-2010-0008

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 2011 and 2012

FINAL ARGUMENT
OF THE
SCHOOL ENERGY COALITION

December 6 , 2010

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0 GENERAL COMMENTS

0.1 *Introduction*

0.1.1 On May 26, 2010 the Applicant Ontario Power Generation filed an Application to set payment amounts for its prescribed facilities for the period commencing March 1, 2011, based on its revenue requirements for the calendar years 2011 and 2012. The Application seeks increases in its hydroelectric and nuclear payment amounts based on revenue requirement for the Test Period of $1.4357 billion for its hydroelectric prescribed facilities, and $5.4739 billion for its nuclear prescribed facilities.

0.1.2 After a lengthy hearing process, the Applicant filed its Argument in Chief on November 19, 2010, and Board Staff filed its Final Argument on November 30, 2010. This is the Final Argument of the School Energy Coalition.

0.1.3 The ratepayer groups who intervened in this proceeding have worked together throughout the hearing to avoid duplication, including exchanging drafts or partial drafts of their final arguments. We have been assisted in preparing this Final Argument by that co-operation amongst parties. Where we are in agreement with the submissions of other parties, we have not repeated their arguments here, but have adopted their reasoning where applicable.

0.1.4 We also note that the Final Argument from Board Staff was particularly helpful in this proceeding, not only for its thorough canvass of the details and evidence relating to various issues, but also for its thoughtful suggestions as to how some of the issues could be resolved. While we have not agreed with all of the proposals put by Board Staff, even where we disagree their submissions have been very useful.

0.1.5 The complexity of this proceeding necessarily requires 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 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.

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

0.1.7 Throughout these submissions, we have referred to the Board's decision in EB-2007-0905 as the Original Decision, the Board's Decision EB-2009-0038 as the Review Decision, and the Board's Decision in EB-2009-0174 as the Extension Decision.

0.1.8 Finally, we note that, as with most Final Arguments, this one is full of specific criticisms of the Application and, by implication, the Applicant. It is important to note that buried in this Final Argument is also recognition that the Applicant and its management are taking steps to make their company better, and that will benefit the ratepayers in the long term. Of particular importance is the Applicant's attempts to shift to top-down, business-oriented planning and budgeting. This will not happen overnight, but it is a very promising sign that this utility is making positive changes. If that fact becomes lost in the details of this Final Argument, we felt it was important to highlight it at the outset.

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 ***Nature of the Inquiry.*** The Applicant is seeking a total revenue requirement of $6,901.0 million over the two year Test Period, plus a net of $373.1 million in clearances from deferral and variance accounts, and a further $250 million owing on those same accounts after 2012. The notional rate increase, including only the current portion of recoveries, is 6.2%.

0.2.3 However, these numbers mask the true extent of the revenue requirement increases being proposed. In addition to these amounts, the Applicant is proposing to reduce revenue requirement by $197.1 million to reflect their "decision" to proceed with the Darlington refurbishment, an accounting adjustment that does not reflect actual reductions in costs or obligations, only deferrals. As well, the Applicant is proposing to defer collection of $264.3 million of pension/OPEB cost increases that they admit are expected to be incurred in the Test Period, but they wish to collect in 2013 and beyond.

0.2.4 In our view, these deferrals, whether or not they should be implemented, cannot be allowed to obscure the reality. When all factors are taken into account, the total amount that the Applicant is actually seeking in this case is almost $8 billion ($7,985.4 million, in fact), a very significant increase over the previous payment amounts. For example, we calculate that the real amount of the payment amounts for nuclear, when all indirect costs are included, is $67.63/MWh, a 23.0% increase over the current payment amounts.

0.2.5 To the extent that the $8 billion is just and reasonable, the Board of course is required to allow recovery in rates. However, in assessing whether the Applicant is making reasonable efforts to keep its costs and rates down, the Board should in our view be conscious of the real amounts of spending that the Applicant is planning (and expecting this Board to accept) for the Test Period.

0.2.6 ***Rate Base.*** We have agreed with Board Staff with respect to reductions to nuclear rate base of $128 million in 2011 and $161 million in 2012.

0.2.7 On the other hand, we support the inclusion in rate base of the St. Lawrence Development Visitor Centre.

0.2.8 ***Operating Costs and Benchmarking.*** OM&A should be reduced, primarily on the nuclear side. We have approached this from two main metrics: benchmarking of Darlington non-fuel costs, and reductions in overall compensation costs to reflect a stepwise move toward the 50^{th} percentile. We have also proposed, or agreed with others, on a number of smaller adjustments.

0.2.9 The Applicant's considerable benchmarking activity since the Original Decision has produced tangible results, and they should be applauded for embracing this exercise with some vigour. There are, however, still significant steps to take, and we propose a number of those steps in these submissions.

0.2.10 ***Darlington Refurbishment.*** We believe that the CWIP in rate base proposal should be denied, but that the Test Period OM&A for the Darlington refurbishment should be approved. We have also proposed that the amount of $245.6 million of credit adjustments to nuclear liability and other accounting entries, net of the tax impacts of those adjustments, should not be implemented by this Board. The result is an increase in revenue requirement of $195.3 million.

0.2.11 Our proposal to increase revenue requirement goes in tandem with a proposal that the Board accept the capital spending on the Darlington refurbishment in the Test Period, but with warnings and conditions designed to ensure that, before the project becomes a fait accompli, it is thoroughly reviewed.

0.2.12 ***Pension/OPEB.*** With respect to pension and OPEB costs, we do not agree that the Applicant should defer recovery of all of the $264.3 million of expected increases until a subsequent rate application. Instead, and recognizing that these costs can be volatile, we agree with Board Staff that they should be recovered on a current basis in the Test Period, but that they should be recovered using the cash basis used by other regulated utilities. The cash costs associated with pension and OPEB are significantly more stable, yet still recover the same total cost over time.

0.2.13 ***Tax Provision in Rates***. Flowing from the analysis of the Tax Loss Variance Account (below), we conclude that the 2011/12 Test Period tax provisions of $58.0 million for hydroelectric, and $129.8 million for nuclear, and associated gross ups, should in fact be zero. This reduces revenue requirement over the Test Period by $262.6 million.

0.2.14 ***Production Forecasts.*** We conclude that the nuclear production forecast should be reduced by 2 TWh., reflecting removal of the proposed new contingency amount that has been labeled "Major Unforeseen Events". This adjustment is not consistent with the Applicant's actual planned results, has not been justified in the evidence, and flies in the face of the Applicant's benchmarking evidence.

0.2.15 With respect to the hydroelectric production forecast, we propose that the adjustments for surplus baseload generation (SBG) be removed from the forecast for the purposes of setting payment amounts. All parties appear to agree that SBG is unpredictable. We propose instead that a variance account be established, to record the revenue impacts of actions by the Applicant to curtail hydroelectric production (i.e. spilling water) where asked to do so by IESO.

0.2.16 ***Tax Loss Variance Account.*** The existence of the Tax Loss Variance account prompted a more thorough review of past and present taxes in this proceeding than in any other Board proceeding in recent memory. The dollars involved, and the complexity of the issues, required deeper digging than is normally required.

0.2.17 In its detailed analysis of the TLVA and related issues, SEC has gone back to the basic principle of "benefits follow costs", required by the Board in the Original Decision, and affirmed in the Review Decision. This has led us to conclude that the approach the Applicant has taken to this issue is fundamentally flawed. By setting up their previous calculation of tax losses, $990 million, and then seeking to identify deductions from that, the Applicant's approach is at 180 degrees from the principle the Board has affirmed.

0.2.18 The benefits follow costs principle requires that the Board focus, not on tax losses, but on the tax deductions associated with each cost that is incurred. Where the ratepayers are ultimately bearing a cost, any tax deductions associated with that cost, whenever they arise or arose, belong to the ratepayers, and they are entitled to take the benefit of them, as and when available, in the form of reduced rates.

0.2.19 In keeping with that principled approach, we therefore conclude that the Applicant has taken tax deductions prior to April 1, 2008 totaling $1,660.4 million that should be available for deduction by the ratepayers, as the ratepayers will be bearing those costs.

0.2.20 As a result, there should have been no regulatory tax liability for the first test period (April 1, 2008 to December 31, 2009), nor for calendar 2010, and there will be none for 2011 or 2012. Rates for these periods should not include any provision for tax payable. The recovery of the 2008/9 mitigation amount of $168.7 million also does not need to be grossed up, because it too is sheltered by those previously taken deductions that rightfully should accrue to the benefit of the ratepayers. After all of those deductions have been used up, there would appear to be $450-$500 million of tax deductions still available to shelter taxable income, for ratemaking purposes, for the period 2013 and potentially beyond.

0.2.21 We therefore propose that the remaining amount of $168.7 million (the mitigation amount), representing the only appropriate balance remaining in the Tax Loss Variance Account, and without any gross up, be recovered from the ratepayers over the period 2011 through 2014 as proposed by the Applicant.

0.2.22 ***Bruce Lease Costs Variance Account.*** Because the major reasons for the debit balance in this variance account relate to unusual one-time events, including $159 million of accounting changes in 2009, none of which are likely to recur in the near term, it is appropriate to clear this account over a longer period, to the end of 2014 rather than to the end of 2012.

0.2.23 ***Other Deferral and Variance Accounts.*** We are unable to reconcile the opening balance in the Nuclear Liability Deferral Account with the Board's Payment Order in EB-2007-0905. As a result, it would appear to us that the amount to be recovered should have been $130.5 million, not $163.9 million, and the balance remaining to be recovered should be $6.0 million, not $39.4 million, subject to any interest adjustments that should reduce this further.

1 GENERAL

1.1 *Board Directions*

1.1.1 The Original Decision sets out a number of directions from the Board for actions that the Applicant should take in this Application, and the Review Decision and Extension Decision have provided additional directions. 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*

No additional submissions.

1.3 *Overall Increase in 2011 and 2012 Revenue Requirement*

1.3.1 ***Increased Revenue Requirement.*** The proposed revenue requirement for the Test Period January 1, 2011 to December 31, 2012 was $6,909 million [Ex. I1/1/1, Table 1], but that has subsequently been reduced by $8.8 million relating to the Fuel Channel Lifecycle Management Project that was apparently double counted [AIC, p. 98]. The result is a revenue requirement of $6,901 million, subject to our comments below. This includes a revenue requirement of $3,397 million for 2011 and $3,504 million for 2012.

1.3.2 This compares to the 2009 revenue requirement of $3,438.2 million [Rate Order EB-2007-0905, App. A., Table 3], indicating a drop in revenue requirement of $41.4 million for 2011, then an increase of $107.4 million for 2012 to leave it $66.0 million higher than 2009.

1.3.3 This is primarily because of a $106.8 million drop in the annual nuclear revenue requirement from the $2,779 million approved for 2009 to $2,673 million proposed for 2011. It is proposed to increase from 2011 to 2012 by $110.0 million, at which point it would be slightly higher than 2009.

1.3.4 Meanwhile, the Applicant has proposed that the hydroelectric revenue requirement increase from $658.8 million in 2009 to $724.2 million in 2011 (a 9.9% increase), and then drop to $711.6 million for 2012 (a net increase of 8.0% over three years).

1.3.5 This can be summarized as follows:

Summary of Revenue Requirement			
$M	*2009*	*2011*	*2012*
***Nuclea**r Revenue Requirement*	2,779.4	2,677.5	2,796.5
Less: Double-counting adjustment	0.0	(4.9)	(3.9)
Proposed Nuclear Rev. Req.	2,779.4	2,672.6	2,792.6
Deferral and Variance Accounts	100.7	227.1	232.8
Total Amounts to be Collected	2,880.1	2,899.7	3,025.4
***Hydroelectri**c Revenue Requirement*	658.8	724.2	711.6
Deferral and Variance Accounts	0.0	(39.5)	(47.3)
Total Amounts to be Collected	658.8	684.7	664.3
Net Revenue Requirement	3,438.2	3,396.8	3,504.2
Net Deferral and Variance Accounts	100.7	187.6	185.5
Net Amounts to be Collected	3,538.9	3,584.4	3,689.7

1.3.6 ***Increase of Total To Be Collected From Ratepayers.*** It is important to note that the total amounts to be collected from ratepayers are not limited to the revenue requirement amounts. They do go up further because of substantial increases in nuclear variance account dispositions, somewhat offset by hydroelectric credit balances. It should also be noted that at the end of 2012, there is proposed to be a substantial balance still outstanding in the Tax Loss Variance Account, perhaps $250 million, which would remain to be collected in 2013 and 2014.

1.3.7 However, we note that there are additional significant impacts that are not included in the proposed revenue requirements, nor in the deferral and variance account dispositions. Two are of particular note: the accounting change relating to Darlington refurbishment, and the additional anticipated expenses for pension costs in the Test Period.

1.3.8 The Darlington impact is the $197.1 million reduction in revenue requirement [D2/2/1, page 3] falling out of the decision to proceed with the Darlington refurbishment. The reduction occurs because of an accounting change, and does not represent a reduction in actual amounts to be paid by the ratepayers. Indeed, the plan to refurbish Darlington carries with it huge future costs for the ratepayers. As we discuss later in this Final Argument, this change has nothing to do with cost reduction efforts or “top-down” business planning. It is just a decision to treat these costs as payable later, i.e. a deferral.

1.3.9 The Applicant proposes a similar fate for pension/OPEB cost increases. These cost increases, currently expected to be $264.2 million [N/1/1, pp. 3-4] are clearly applicable to the Test Period. However, the Applicant proposes that they be deferred in a new Pension and OPEB Variance Account, then cleared in a subsequent proceeding. The appropriate Board response to this request is discussed later in this Final Argument. At this point, it is just appropriate to say that it is once more a deferral of a cost that, on an apples to apples basis with the current year, would be included in revenue requirement.

1.3.10 These two deferrals - $197.1 and $264.2 million – total $461.3 million, and if the December 31, 2012 proposed balance of the Tax Loss Variance Account, about $250 million, is also included, represent $711.3 million of additional amounts to be collected from the ratepayers after 2012.

1.3.11 We note that for each of these three amounts, the essence of the Applicant's proposal is for the Board to make an accounting/regulatory decision to defer collection from ratepayers until after the Test Period. The accounting decisions are different in each case (lengthen the variance account recovery period, place expenses in a new variance account, and calculate amortization on a longer time period), but conceptually they are all decisions to defer collection.

1.3.12 It is therefore this total that we believe should be the focus of the Board's attention in its decision: **about $8 billion in total financial consequences of this decision to ratepayers**. (Calculated as $6,901 million revenue requirement, $373.1 million clearances, and $711.3 million of additional amounts, all totaling $7,985.4 million.) To put this in perspective, the total amount to be recovered under the Original Decision for a 21 month period was $6,180.6 million. To compare fairly, this would gross up to $7,063.5 for a two year test period, implying a 13.1% increase in amounts to be collected from the ratepayers.

1.3.13 Of course, we are not suggesting that the Applicant is somehow seeking a "hidden" 13% rate increase in revenue requirement. Not all of these amounts are directly comparable. But, it is unquestionably true that all of these amounts are being sought from the ratepayers, sooner or later. A $922 million increase in the amount being sought from the ratepayers in this Application is, it is submitted, cause for serious concern.

1.3.14 ***Increase in Payment Amounts***. A similar analysis reveals that the proposed increase in the payment amounts may also be more than it first appears. While the hydroelectric payment amount is proposed to be relatively flat, the ratepayers will be paying much more for nuclear if the Application is accepted as filed.

1.3.15 For hydroelectric, the current payment amount is $36.66/MWh (including disposition of deferral and variance accounts), and the Applicant proposes to increase that to $37.38/MWh, more than offset by a credit rider of $2.46/MWh. for deferral and variance accounts [I1/2/1, Table 1]. This produces a net cost of $34.92/MWh, a 4.7% drop in net unit cost.

1.3.16 For nuclear, the story is a little different. The Applicant proposes to increase the payment amount from $52.98/MWh to $55.34/MWh. This does not include recovery of deferral and variance accounts, and it does not reflect the amounts totaling $711.3 million described above that are being deferred through accounting decisions until after the Test Period.

1.3.17 To reanalyze the nuclear payment amounts, in our view it is appropriate to look at the existing payment amounts and add the $2.00 existing rider for deferral and variance account recoveries. This makes the effective cost of nuclear energy in the prior period $54.98/MWh. For the forward test period, it is appropriate to add the amounts proposed to be recovered for deferral and variance accounts ($459.9 million), which convert to a rider of another $5.09/MWh [I1/3/1, Table 1]. It is also appropriate to take into account the amounts proposed to be deferred through accounting decisions ($711.3 million), which convert to a notional rider of another $7.20/MWh. **Thus, when all is taken into account, the effective cost of nuclear for the Test Period is proposed to be $67.63/MWh., an increase of 23.0% over the existing cost.**

1.3.18 We fully understand that the Applicant is actually proposing payment amounts including riders of exactly $60.43/MWh. ($55.34 plus $5.09), a 9.9% increase, but schools, like many ratepayers, take a longer view. Yes, it is useful to defer payment of significant amounts if there are other pressures on rates. That doesn't mean the costs go away. They still will have to be paid and, since now is the time that the costs are being incurred, now is the time to assess whether they are reasonable.

1.3.19 Our view is that the evidence does not demonstrate a strong justification for a 23.0% increase in the cost of nuclear energy. In reviewing the remainder of the Application, we therefore come from the perspective that there are probably savings to be found, sufficient to bring that 23.0% down to a more reasonable level. Only when that reasonable level has been identified is it appropriate to then consider the timing of recovery of those costs.

1.3.20 We believe the Board should take the same approach.

2 RATE BASE

2.1 *Overall Amount of Rate Base*

2.1.1 Staff has provided an analysis of nuclear rate base [Staff Argument, pp. 19-22] proposing reductions of $128 million in 2011 and $161 million in 2012.

2.1.2 SEC agrees with Staff's submissions on this issue, and adopts their reasoning.

2.1.3 We note that Staff has also proposed a reduction to hydroelectric rate base. For the reasons we have set out in Section 4.3 of this Final Argument, SEC does not agree with that reduction.

2.2 *CWIP in Rate Base Proposal for Darlington Refurbishment*

2.2.1 ***Background.*** The Applicant has proposed that the construction work in progress (CWIP) for the Darlington refurbishment should be included in rate base commencing at the date of the decision to proceed with the project, i.e. January 1, 2010. The impact on revenue requirement for the Test Period is $37.9 million [Tr.13:64].

2.2.2 This is a significant alteration of the normal rule that assets are closed to rate base when they are "used and useful". The Darlington refurbishment expenditures are not expected to be "used and useful" until 2020/21. However, the Board, in its EB-2009-0152 Report, has expressed its willingness to consider applications to have CWIP included in rate base in special cases, such as projects supporting the Green Energy and Green Economy Act and other instances. OPG claims that this policy should extend to their nuclear project spending.

2.2.3 In fact, if approved by this Board panel, the impact of including Darlington CWIP in rate base is not $37.9 million over two years, but between $740 million and $1.1 billion [Tr.13:92 and K13.4]. That is the amount that ratepayers will have already paid, under the Applicant's proposal, before they receive any benefit from the Darlington refurbishment spending.

2.2.4 The Applicant says there are two reasons why this proposal should be approved: minimization of rate shock at the time the new assets come in-service, and the impact on the cost of debt and the Applicant's creditworthiness today [AIC p. 76].

2.2.5 SEC is opposed to the CWIP in rate base proposal for Darlington refurbishment for a number of reasons, set forth below.

2.2.6 ***The Spectre of "Rate Shock".*** There are two reasons why the spectre of rate shock is not realistic in this case.

2.2.7 First, there is no specific point in time when the rates actually take a big jump as Darlington refurbishment comes on stream. Because there are multiple units, and they will not come into service at the same time, or even in the same year, and because at the same time the Applicant expects that Pickering units will be coming out of service, also with significant impacts on rates, the actual payment amounts are not expected to have a sudden jump in a single year, even without the CWIP treatment proposed [see our discussion on this with Mr. Barrett at Tr.13:94-5].

2.2.8 In fact, given the forecast LUEC for the refurbished Darlington units of six to eight cents per kwh. [Tr.13:31], and the current effective cost of nuclear in the Test Period of $67.63/MWh [see our earlier discussion], if the project comes in on time and on budget it is difficult to understand how the impact could be that earth-shattering anyway. While the new assets may well cost more, the very expensive Pickering units will be phasing out, so it may be a fairly even trade.

2.2.9 Further, to the extent that there is a rate impact, it will be muted at that time, because the Darlington is in total expected to be no more than about 8% of the total generation in the province when the refurbished units come into service [K16.2].

2.2.10 Second, even if there is a rate smoothing effect arising out of the CWIP in rate base proposal, it is solely because the ratepayers will have prepaid a substantial portion of the cost of the asset. This prepayment represents a material negative consequence of this proposal to ratepayers.

2.2.11 In effect, the Applicant is asking the ratepayers to buy the Darlington refurbishment on a layaway plan. In the same way that, a generation or more ago, couples bought their engagement and wedding rings by setting aside a small amount each week from their pay cheques, eventually building up enough in their account with the jeweler to buy the rings, so too the Applicant wants the ratepayers to pay for Darlington refurbishment in advance. The theory appears to be – as with the traditional layaway plan – that we will not be able to afford it if we don’t start setting money aside today.

2.2.12 The Applicant appears to have taken the view that there is minimal cost to the ratepayer for this prepayment. This is simply not true.

2.2.13 For some ratepayers, of course, an additional cost this year means that borrowing must increase. Where that is the case, it is hard to imagine there are many ratepayers whose cost of borrowing is less than that of the Applicant (except perhaps schools and other government bodies). For individuals, it may even be at credit card rates, many times the cost of borrowing for the Applicant. Therefore, if the cost of this prepayment is determined solely in financial terms, for almost all ratepayers the financial cost of prepaying is higher than the financial cost of paying the full cost of the electricity, including interest during construction when the power is actually being generated.

2.2.14 In the real world, though, ratepayers rarely borrow to finance higher electricity bills. It is a current cost, so they adjust their other current costs accordingly to offset. This zero-sum activity is one that families, businesses and institutions face on a regular basis.

2.2.15 For the family paying the electricity bill for their home, this additional cost means they will have to cut back in other areas. It may be real luxuries, or it may be summer camp for one of the kids. For a small business, paying a higher electricity bill means the part-time counter clerk or shipper is no longer affordable. For a school, that higher bill may mean that the enrichment program has to be curtailed.

2.2.16 Of course, for any given rate increase, the offset may not be overwhelming. The additional CWIP cost of $1.1 billion likely means only about $3/4,000 for each school in the province, and that is over ten years. For a large school board, like Toronto District, that would mean that, sometime over that period, they have to find an additional, say, $2.5 to $3.0 million. Cutting the enrichment program in one school, and the music program in another, may be enough over ten years to solve that problem.

2.2.17 But this is not the only pressure on electricity costs, or on the overall operating costs for the Applicant's ratepayers. Transmission and distribution costs are also increasing, and the costs of other generation are not expected to decline in that period. It all, as they say, adds up.

2.2.18 In our submission the additional cost that the Applicant is proposing to impose on ratepayers, including schools, is not insignificant, and should not be treated lightly. This, if approved, will represent a cost to ratepayers, not just in dollars, but in other activities and priorities that have to be left behind. If it is necessary, fine. But if it is not required for the Applicant's purposes, in our submission it should be rejected.

2.2.19 In short, on the rate shock issue our view is that we and other ratepayers would prefer that the Applicant not do us this favour. The real world costs today of this additional rate increase are not worth the "benefit" of avoiding a future rate shock that is ephemeral at best.

2.2.20 ***Impact on the Cost of Debt.*** The Applicant's second rationale for this proposal is that it will reduce the cost of debt, and thus benefit the ratepayers.

2.2.21 To the extent that ratepayers borrow to cover this additional cost, the result is likely an increased financing cost. But, even if this is looked at from the Applicant's point of view alone, the proposition is unsustainable.

2.2.22 On this point, we have reviewed the submissions of Board Staff [Staff Argument, p.

37-8], and we agree with their analysis and conclusion.

2.2.23 We would also note that, given that the decision by the Applicant to proceed with Darlington refurbishment, and therefore accept this increased business risk, was made a year ago, we would have expected to see a response from the bond rating agencies expressing a view that the Applicant's credit risk has increased for this reason. No such evidence was filed.

2.2.24 In fact, both Standard & Poors and DBRS, while referring to the risks associated with the Applicant's nuclear program generally (which in our view are about nuclear, not about CWIP) have left the rating and the trend for the Applicant unchanged since the decision to refurbish. This is not consistent with the claim that failure to get CWIP in rate base will cause an increase in borrowing costs. The Applicant doesn't have CWIP in rate base today, and yet it is spending considerable amounts on the Darlington refurbishment to the knowledge of the rating agencies. Borrowing costs have not increased. The evidence is, in fact, quite clear.

2.2.25 Therefore, it is submitted that the rationale of lower debt costs is unsupported by the evidence.

2.2.26 ***No Necessity.*** That should actually be the end of the discussion. The onus is on the Applicant to show that there is a real reason for the Board to make an exception to the "used and useful" rule in this case. That onus has not been met, and without more it is submitted that this proposal should be rejected.

2.2.27 However, we note that there are two additional reasons why the Board should not accept the proposal, regardless of the rationale put forth by the Applicant.

2.2.28 ***Inconsistent with Board Policy.*** As Board Staff correctly point out [Staff Argument, p. 35-6], the Applicant's request in this proceeding is not consistent with the Board's policy as set out in the EB-2009-0152 Report. We agree with that conclusion, and adopt Staff's reasoning on this point.

2.2.29 We note that the Applicant's July 7, 2009 submission in the EB-2009-0152 proceeding was primarily focused on convincing the Board to expand its application of the proposed special rules for infrastructure investment beyond GEGEA and beyond transmitters and distributors. Their basic point was as follows [page 3]:

> *"OPG sees no justification for the exclusion of other regulated entities from access to the modified regulatory treatment simply based on the entity's position in the value chain... For these reasons, the mechanisms identified in the discussion paper should be applicable to rate regulated entities other than transmitters or distributors."*

2.2.30 They also attach to their submissions the interim report of Charles River Associates, prepared for the Applicant and dated October 7, 2008, entitled "The Economics of Integrating CWIP into Rate Base". This appears to be an early draft of the report filed in this proceeding from the same consultant, dated March 3, 2010, as Exhibit D4/1/1.

2.2.31 The Board was not convinced by the Applicant's argument and expert opinion in EB-2009-0152, and we see nothing that has changed since that time.

2.2.32 ***Implicit Approval by the Board.*** Finally, after some difficulty the intervenors have been able to clarify the Applicant's position on the nature of the approval requested. The clearest statement of this by Mr. Barrett, quoted in full later in this Final Argument, is that the Board should not allow CWIP in rate base unless it is satisfied that "the spending proposed is reasonable" and "the project is a good idea" [Tr.13:87-8].

2.2.33 In our submission, the Applicant couldn't be clearer here. Allowing CWIP in rate base is a green light from this Board to proceed. The Board should not allow this proposal unless it also decides to, in effect, approve the project.

2.2.34 ***Conclusion.*** For these reasons, it is submitted that the CWIP in rate base proposal should not be approved by this Board.

3 CAPITAL STRUCTURE AND COST OF CAPITAL

3.1 *Equity Thickness and ROE*

3.1.1 The Applicant proposes to continue the existing capital structure of 53% debt and 47% equity for all of the prescribed facilities, and to apply the Board's new ROE calculation to obtain a current ROE, likely in the range of 9.6%. The numbers in the Application are calculated on the basis of 9.85% (an increase from 8.65% currently included in the payment amounts), but it is our understanding that the Applicant proposes to use in the rate order the ROE calculated as of three months prior to the effective date of the payment amounts [AIC, p. 65].

3.1.2 It would appear to us that the basic approach being taken by the Applicant is accepted by all parties, with two exceptions. First, there is a discussion about whether hydroelectric and nuclear should have different capital structures or ROE. We discuss that under Section 3.3 below. Second, there is a proposal to determine the 2012 ROE today based on a new forecasting source.

3.1.3 The Applicant took the unusual approach, in the EB-2007-0905 case, of seeking payment amounts that would stay the same for an extended period, in that case originally 21 months and eventually 33 months. There was no annual adjustment, as would be the case for most regulated utilities. A single ROE was determined at the outset.

3.1.4 In this proceeding, the Applicant proposes a similar treatment, i.e. forecasting ROE for both 2011 and 2012, and averaging that cost, along with all other costs, to get payment amounts that would apply for the full 24 month test period (or until the Applicant seeks a new payment amounts order).

3.1.5 While the two year blended test period approach is certainly unique, it is not unreasonable. Not only has it been accepted by the Board in the Original Decision, but there is some merit to having stability in the cost of most of the province's electricity, especially when there are so many other changes in the electricity bill expected over the same period. Further, fixed ROE is the method used for most rates, since most rates are established annually based on IRM, which does not include an ROE update.

3.1.6 Board Staff, in their Final Argument [pp. 9-12], have taken the also quite reasonable position that ROE is generally updated by the Board on an annual basis when rates are being set on a cost of service basis. They cite the EB-2007-0680 decision relating to Toronto Hydro, and the EB-2009-0096 decision relating to Hydro One as precedents for the view that, on a multi-year cost of service application, the ROE should be updated annually. They also note that forecasts get more certain as you go further out (which is, we assume, why Consensus Forecasts do not provide such a forecast).

3.1.7 Of relevance also is the fact that the Applicant proposes to use a different forecasting source, Global Insights, because the Consensus Forecasts that the Board has used for many years are not available that far out.

3.1.8 In our submission, either approach can be justified based on the evidence and based on consistency with Board policy.

3.1.9 On balance, we believe that fixing the payment amounts for a two year period is a valuable result, and therefore believe that fixing the ROE for the 24 month period is also a good idea. However, we think it is inappropriate to shift to a new forecast source without a more thorough review, and we are concerned about the uncertainty of market forecasts two years out.

3.1.10 What we believe the Board should consider, as an alternative, is to use the ROE determined now for 2011, and retain it for 2012. While this would not be a forecast of the ROE for 2012, it would be consistent with IRM, in which the forecast for the rebasing year remains in rates for the IRM years. It has the advantage of simplicity, and consistency with the bulk of the Board's rate setting decisions.

3.1.11 In the event that the Board does not believe that accepting the current rate is appropriate, then in our view it would be better to adopt the position of Board Staff, and reset the rate next fall. While there is a value to price stability, particularly at this time, it is not sufficient to justify using a new and untried forecasting source for a period where the forecast is likely to be less reliable in any case.

3.1.12 We note in passing that the updating of the ROE and the updating of the short term and long term debt rates have a number of common elements, yet we have taken different positions on the equity and debt components. In our view, the updating of debt is more akin to forecasting OM&A and similar costs, whereas updating ROE – i.e. the inputs to a formula established by the Board – is less like that. We are more concerned with the use of a new forecasting source in this case than in the case of debt costs. We do acknowledge, however, that this is not a clear cut distinction.

3.2 ***Cost of Debt***

3.2.1 ***Actual Long Term Debt.*** The Applicant has provided forecasts of the cost of actual existing and proposed long term debt, 5.53% in 2011 and 5.50% in 2012 [AIC, p. 66]. Those forecasts, and the evidence supporting them, appear to be reasonable. We note that the Board's deemed rate, established November 15, 2010, is 5.48%, which suggests that the Applicant's forecasts are in the ballpark.

3.2.2 ***Notional Long Term Debt.*** For the component of the capital structure that is required to be long term debt, but is not actually represented by real long term debt, the Applicant has proposed that the rate used should be the Board's deemed rate, which was at the time of the Application 5.87%. Board Staff has noted that this proposal is inconsistent with Board decisions, and is based on a clearly incorrect interpretation of the Board's 2009 Cost of Capital Report, but Staff then goes on to suggest that, since the new deemed rate of 5.48% is lower than, and close to, the actual debt cost, "the Board may wish to consider accepting OPG's proposal in this Application" [Staff, p. 8].

3.2.3 With respect, we strongly disagree. The Board has an established interpretation and practice relating to notional long term debt. If the Board in this case allows the Applicant's proposal, the Board will then have two established interpretations and practices, and will in effect be inviting utilities to select the approach that gives them the highest revenues in any given year. This is clearly inappropriate. The Board's deemed rate is intended to be available where there is no other evidence of the utility's cost of long term debt. In this case, there is ample evidence of OPG's long term debt rate, and a deemed rate adds nothing.

3.2.4 In our view, when the Board has sufficient evidence before it on an issue, it is proper to follow that evidence in reaching its decision. It is not proper to fall back on a default value or deemed amount in the face of direct evidence on the point.

3.2.5 Therefore, it is submitted that the weighted average long term debt rate for OPG's actual long term debt should be applied to the entire amount of LTD capital required under the approved capital structure.

3.2.6 ***Short Term Debt Update***. The Applicant has proposed short term debt rates for both 2011 and 2012, based on December 2009 forecasts from Global Insights. The use of this dated information results in substantial increases in the cost of short term debt from 2011 to 2012.

3.2.7 In principle, we believe that the short term debt rate, like the long term debt rate, should be based on the best evidence currently available. In this case, using a year old forecast, particularly when it is being applied to two forward years, is inappropriate. Instead, it is submitted that the forecast of short term debt costs should be updated using December 2010 forecasts. We would anticipate that this will result in a material reduction in the cost of short term debt for the Test Period.

3.3 ***Different Capital Structures/ROE for Hydroelectric and Nuclear***

3.3.1 The Applicant has proposed to continue the approach, approved in the Original Decision, of using the same capital structure and same ROE for both the hydroelectric and nuclear assets. They have presented the evidence of Ms. McShane in support of that approach. GEC presented the evidence of Mr. Chernick, and Pollution Probe presented the evidence of Drs. Kryzanowski and Roberts, supporting a greater equity thickness and therefore equity cost for nuclear as compared to hydroelectric.

3.3.2 In EB-2007-0905, SEC and others took the position that using a higher equity thickness for nuclear is justified and appropriate. The Board, while not accepting those arguments, did note in the Original Decision that the issue was worthy of further review. The continued debate in this proceeding arises out of that conclusion.

3.3.3 Notwithstanding our previous position, SEC's view on this issue has evolved. We no longer believe that it is appropriate, whether on the evidence or as a matter of policy, to have separate costs of equity (through different equity thicknesses or different ROEs) for hydroelectric and nuclear for ratemaking purposes. We do, however, continue to believe that this is an appropriate distinction for planning purposes.

3.3.4 Other parties will analyze the evidence of the experts at some length, and we will leave that debate to them. What we conclude from the experts, and the debate around their evidence, is that:

(a) There is almost certainly a difference in business risk between the operation of hydroelectric and of nuclear facilities. No-one seems to disagree with this.

(b) Making an empirically-driven distinction between nuclear and hydroelectric, sufficient to ground actual numbers for different costs of equity, is difficult to achieve on the basis of the data in the marketplace. It is not impossible, but the Board would be exercising considerable seat of the pants judgment if it did so.

3.3.5 Our analysis of this issue, though, comes from two other perspectives: the nature of the fair return standard, and the policy rationale for separate costs of equity. Both lead us to the conclusion that the separate costs are not justified.

3.3.6 ***Fair Return Standard***. All discussion of cost of capital must start with the fair return standard, which as the Applicant correctly points out is a "legal requirement" [AIC p. 64]. The Applicant in fact quotes the seminal Supreme Court of Canada case on the issue, *Northwestern Utilities v. City of Edmonton* [1929] SCR 186 at 192, that quote saying:

> *"By a fair return is meant that a <u>company</u> will be allowed as large a return on the capital invested in its <u>enterprise</u>…as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the <u>company's enterprise."</u> [emphasis added]*

3.3.7 The emphasis brings to focus what the fair return standard is all about. The regulated entity has a regulated business. That business – the "enterprise" – will have many assets of various types, but it is not those assets on which a return is granted. Rather, it is on the overall enterprise.

3.3.8 This makes sense for a number of reasons. As the Applicant correctly points out [AIC p. 69], they borrow in the marketplace as a company, not against individual assets, and their cost of borrowing is set on a company-wide basis. Their equity, if it were offered, would be on the same basis.

3.3.9 This is consistent with our understanding of the market. The overall risk of a company's equity is set by many parameters, and on the business risk side those parameters include the risks related to individual activities, and the ways in which those risks are either directly or inversely correlated.

3.3.10 In fact, one of the key aspects of risk minimization is diversification of risk. In our view, assigning equity thicknesses or ROEs to nuclear and hydroelectric individually would necessarily involve not only the risks of those two components, but also an assessment of the interaction of those risks, and how that interaction (whether resulting in a net increase or decrease) should be allocated between them. That exercise, in our view, is not productive, as it is divorced from reality.

3.3.11 These market realities suggest that maintaining the traditional view of the fair return standard – calculating it on an entity-wide basis – is appropriate.

3.3.12 The other main reason for refusing to reinterpret the fair return standard is that it could have significant unintended consequences. Right now, a utility in a rate application treats their assets as, effectively, all having the same cost of capital, as a package. If the Board adopts separate costs of capital for different assets in this case, it is virtually certain that parties will seek to apply the same principle to assets of other regulated entities.

3.3.13 The most obvious example of this is new major projects. A distribution utility, for example, carrying out an expansion in a part of their franchise area that is currently undeveloped, may say quite correctly that there is more business risk associated with this project than with its existing infrastructure serving mature areas. Does the Board want to have an ROE discussion about each major capital project?

3.3.14 A less obvious example is those assets that do not directly generate revenues. A utility decides to implement an Enterprise Resource Planning system costing millions of dollars. Intervenors would presumably be free to argue that the return on this new asset should be based on the savings it will generate. If it is unable to generate the same level of net "revenues" (i.e. cost savings) as an expansion into a new subdivision, perhaps it should not have the same return. Or, if its ability to generate a net benefit is less certain than the new subdivision feeder, that means higher risk, and therefore it should have a higher return.

3.3.15 The fair return standard is applied on a company-wide basis for good reason. In our view, absent a compelling policy reason for having different costs of equity, it is unwise for the Board to reinterpret and expand the fair return standard in this proceeding.

3.3.16 ***Policy Implications.*** The last discussion leads inevitably to the question of what would be the purpose of having separate costs of equity for nuclear and hydroelectric. To assess that question, the Board in our view has to consider that the cost of equity for the Applicant is both a cost (to the ratepayers) and a profit level (to the Applicant). Although for ratemaking purposes it is always treated as a cost, in fact it is the basis of the Applicant's profit, and that can never be forgotten.

3.3.17 Getting the cost "right", if that is possible, through different costs of equity, could be justified on the basis of price signals in the market. In effect, the argument is that if nuclear is more expensive than hydroelectric, then the price in the marketplace should reflect that cost differential.

3.3.18 While that is fine in principle, it does not fly in this case, for two reasons.

3.3.19 In the first place, most of the cost of nuclear has been treated as a stranded asset and shifted to Ontario Electricity Finance Corporation ($16.4 billion, perhaps). The figure we have cited earlier in this Final Argument, an effective unit price of $67.63/MWh., is nothing more than a fiction. If the full capital cost of the nuclear assets were to be included in its pricing, the cost would likely be in the range of $90.00-$130.00/MWh. Against that background, what is the value of altering the "price signal" through varying the cost of equity? In our view, it is immaterial in this context. Everyone knows the existing nuclear stations are producing very expensive electricity. Further reminders are not required.

3.3.20 In the second place, for a "price signal" to have value, it must have the ability to change someone's behaviour. Who is being signaled here? Consumers cannot choose whether to buy nuclear power or not. IESO does not dispatch based on the payment amounts. And, presumably the government and OPA make system planning decisions based, not on the payment amounts, but on forecast future costs (on which, see below).

3.3.21 It therefore appears to us that the purpose of having separate costs of equity for nuclear and hydroelectric cannot be price signals.

3.3.22 The other aspect, though, is that cost of equity is the profit level for the Applicant. If nuclear is accorded a higher cost of equity, as some propose (through equity thickness or higher ROE), the effect is that the Applicant makes more money by investing in nuclear than they do by investing in hydroelectric. In effect, the higher cost of equity for nuclear would be an incentive to invest in nuclear over hydroelectric.

3.3.23 There are some who might argue that there should be incentives to invest in nuclear, but in our view this Board does not have evidence before it warranting such a policy conclusion, even if it is within the Board's mandate in this proceeding (which we doubt).

3.3.24 Further, while the government does have a policy supporting the continued use of nuclear, the overall thrust of government energy policy strongly favours renewable options over non-renewable options. An incentive to invest in nuclear would mean that, faced with limited resources, the Applicant should invest its next $100 million in a new nuclear project rather than a new hydroelectric project, all other things being equal. We would be very surprised if the government were to interpret its policies as consistent with incentives to spend incremental dollars on nuclear at the expense of hydroelectric.

3.3.25 It is therefore submitted that separate costs of equity are not justified on the basis that the Board should incent the Applicant to prefer nuclear investment over hydroelectric investment.

3.3.26 ***Planning Assumptions.*** The one area in which differences in the cost of capital may be appropriate is planning new spending. The Applicant today makes business decisions about where to spend money, and those decisions are largely driven by the effect of those investments on the company relative to the risks. It is, we believe, appropriate to reflect in those planning analyses the fact that spending on nuclear may tend to increase the company's risk, and therefore cost of capital, over time, while spending on hydroelectric may have the opposite effect.

3.3.27 By way of example, the Applicant plans to spend $10 billion or more to refurbish the Darlington station. It is self-evident that this massive spending program will tend to increase the company's business risk, and therefore increase its overall cost of capital. While most of that will likely be reflected in the cost of debt, wherever the cost impact is felt, in our view it should be a cost allocated to that project. If it means an overall increase of 20 basis points in the cost of all of the Applicant's debt because the market sees the Applicant as more risky, and that increase translates to $20 million in additional annual interest, that $20 million annual cost is a direct cost of the Darlington refurbishment, and should be included as a cost in any business case analysis. This is just good planning.

3.3.28 We therefore believe that the Board should require the Applicant, in their planning for new capital spending, to take into account any increased financing costs company-wide associated with the new project's impact on overall creditworthiness. As long as the Applicant continues to accept the Board's ROE calculation, this will only impact the cost of debt, but the market will price that risk in, and it should be properly allocated to the project creating the cost.

4 CAPITAL PROJECTS

Regulated Hydroelectric

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

4.1.1 ***Niagara Tunnel Project.*** Although this project is not closing to rate base in the Test Period, it is expected to close in 2013, and when it does it is expected to be a project to which Section 6(2)4 applies. The Board has, in PO #3, made clear that its interest in the Niagara Tunnel Project is limited at this time, and no prudence review is being undertaken. Rather, a general status report is what was expected, and provided [D1/1/2, Attach. 1, and JX2.4].

4.1.2 From SEC's point of view, the goals we had when we sought to ensure this was included in the Issues List have largely been achieved. The first thing is that the Applicant has provided significant and useful information on how this project is going, and the Board now has a clearer picture of the potential concerns that may arise when the prudence review does take place.

4.1.3 The second thing that we hope has happened is that the Applicant has been made aware of the concerns of the ratepayers groups and others about where this project is heading. While the evidence appears clear that the Applicant was already very sensitized to the potential concerns about cost overruns on this project, the process of answering questions publicly about what they are doing can only help to reinforce that result. Just by looking at the questions parties asked, the Applicant will have a heads up about what will be asked three years from now. If nothing else happens but the Applicant ensures that those concerns are addressed, the inclusion in this proceeding will have been worthwhile.

4.1.4 Third, and potentially most important, the Applicant went on the record making key commitments about where the project will end up. The point of that is not so much to hold OPG management to those commitments. Instead, it is simply to have those commitments out there. Experienced and capable senior executives, having stood up in public and said things will happen, are in our experience highly motivated to make sure they do happen. In effect, they will likely hold themselves to those public commitments.

4.1.5 Having said this, in our view some additional reporting on the status of this project would continue to be of value. OPG executives will be reporting internally anyway, probably more often than annually. For the Board to ask that a further status report be provided, say once a year until the project is complete, is not unreasonable. This would require a report in June of 2011, and another in June of 2012. At that point, it is possible that a new payment amounts application will be in the works, including if the project is on schedule the in service date for the project in 2013.

4.1.6 However, if the reports are showing continued problems and overruns, the Board will have the visibility necessary to take action if required. By way of example, for 2010 the Applicant was expected to have a new cost of service application, but it did not. Instead, it sought an accounting order to effectively extend some aspects of its existing order (the Extension Decision). If that were to happen again for 2013 (as we think it well might), the extra visibility the Board had on the Niagara Tunnel could, if the project is in trouble, prompt the Board to consider not allowing that one project to wait another year for review. As another example, if the report in summer of 2011 showed another significant cost overrun, the Board could call the Applicant in for a mini-hearing on the subject, and perhaps even put in place checks and balances so that overspending does not get out of hand.

4.1.7 In the best of all possible worlds, the project goes as planned and the annual reports on this substantial project gather dust. On the other hand, in the event of further problems an early warning system could prove valuable.

4.1.8 As a side benefit, the implementation of limited reporting for this major hydroelectric project could be a learning experience for the Board, the Applicant, and other stakeholders. The Applicant expects to engage in a number of multi-billion dollar projects in the next decade. If the Board takes this opportunity to try out annual reporting for the Niagara Tunnel project, that may help the Board in determining how to keep on top of the even bigger spending and commitments in the nuclear projects. Call it a pilot project for annual project reporting.

4.1.9 Therefore, SEC recommends that the Board direct the Applicant to file annual status reports on the Niagara Tunnel Project by June 30th of each year commencing in 2011.

4.2 ***Capital Expenditures and Commitments – Regulated Hydroelectric***

4.2.1 We have reviewed the capital plan for the hydroelectric stations, and in general we believe that it takes a reasonable and balanced approach. We have comments on only two of the projects proposed in the hydroelectric capital plan. In Section 4.1 above, we discuss the Niagara Tunnel project. In Section 4.3 below, we discuss the St. Lawrence Power Development Visitor Centre.

4.3 ***Test Period Additions – Regulated Hydroelectric***

4.3.1 ***St. Lawrence Power Development Visitor Centre.*** The Applicant has spent $12.6 million for this visitor centre near the Saunders facility. It opened in 2010, and the Applicant proposes to treat it as an in service addition in 2010, and therefore part of opening 2011 hydroelectric rate base.

4.3.2 Board Staff, and perhaps other parties, argue that the Visitor Centre should not be part of the rate base for the prescribed facilities. SEC disagrees.

4.3.3 The reasons for opposing rate base treatment are set out clearly by Staff [Staff Argument, pp 22-24]. The fundamental argument is that the Visitor Centre is not required in order to operate the Saunders facility. Supporting that are arguments that three central elements of the Visitor Centre are a) promotion of the OPG brand, b) regional tourism, and c) benefits to unregulated OPG operations.

4.3.4 With respect, SEC believes that Staff and intervenors who oppose the Visitor Centre have approached this question from the wrong perspective. Instead of asking whether the Visitor Centre will somehow help the Applicant produce more electricity from Saunders, or produce it more efficiently, we believe that the parties and the Board should be asking whether this is a normal and usual part of the business of generating electricity from the Saunders facility. We believe that it is.

4.3.5 In our view, any private sector company carrying on a business with the size and local impact of the Saunders facility would, as a matter of course, look for ways to integrate the operations into the local area, and foster goodwill with the local community. Call it public relations, bridge-building, or whatever, it is actually nothing more than good corporate citizenship. Businesses should not simply put up their factories and coldly siphon maximum profits from their presence in a local community. They should, instead, seek to ensure that their profit-making activities, while efficient and productive, fit in and complement their environment. This is true whether the issue is the architecture of the building, how much smoke is coming out of the stack, or the ability of the local community and visitors to see and understand what the business is doing.

4.3.6 SEC believes that regulated utilities should still be good corporate citizens. Indeed, to the extent that they are publicly-owned, they should probably want to set an example of good corporate citizenship. Certainly that part of the activity of a utility has to be scrutinized, and excessive spending for this purpose should be curtailed, just as it would be in a competitive business. But within reason, regulated entities are important parts of their communities, and should act in a manner that accepts and meets that responsibility.

4.3.7 In this context, we believe it should be obvious that not every expenditure by a regulated utility can be tied directly to a gain in productivity, or a revenue stream, or some other financial benefit. Some spending is just a normal part of running a business.

4.3.8 For example, many companies, including utilities, sponsor holiday parties for their employees. Do happier employees work better? Probably, but we would never expect this Board to seek a review of the "business case" for the holiday party of XX Hydro.

There is no business case, and there doesn't have to be. It is just how you should treat people. Nothing more complicated than that.

4.3.9 The Visitor Centre is in the same category. The Saunders facility is a dominant business activity in the Cornwall area. It is not appropriate for OPG to allow it to just sit there silently. Like any good neighbour, the Applicant should be finding a way to offer an open door to local residents, in effect inviting their neighbours in to look around. They have done so, and should not be criticized for it.

4.3.10 The one aspect remaining is whether the unregulated business should contribute to the cost of this. The Board will be aware that SEC has long been a "hawk" with respect to collateral benefits (we often call them "offshore profits") enjoyed by unregulated businesses, but paid for by the customers of affiliated regulated businesses.

4.3.11 We have not changed our view on this principle, but this is not the appropriate case in which to apply it. The St. Lawrence Visitor Centre is virtually entirely about the Saunders facility. Yes, there will be information about other hydroelectric activity in Ontario. That is a natural part of the story. But we have no doubt that the size and cost of the Visitor Centre, and its message, would be unchanged, even if OPG owned no unregulated hydroelectric facilities.

4.3.12 We therefore believe that any benefit to the unregulated facilities or the OPG brand from the Visitor Centre spending is incidental to the primary purpose of the Visitor Centre, and no cost allocation or other contribution is warranted.

Nuclear

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

4.4.1 See our comments under Section 4.5, below.

4.5 *Capital Expenditures and Commitments - Nuclear*

4.5.1 Except where we have commented under separate headings in this Final Argument on nuclear capital spending and commitments, either as part of general issues or specifically, we will limit our submissions in this area to the Darlington refurbishment.

4.5.2 Our general conclusion is that the Board should approve spending on the Darlington refurbishment project for the Test Period, but advise the Applicant to aggressively limit its ongoing financial commitments on the project, as those may not be approved by the Board if the project does not proceed. We also conclude that the $197.1 million reduction in revenue requirement that the Applicant says is the consequence of proceeding with the project is premature, and should not be implemented at this time.

4.5.3 ***Darlington Refurbishment Expenditures - Background.*** The Applicant has embarked on a spending program for a new capital project, the Darlington refurbishment. The purpose is to extend the life of the Darlington units, currently expected to cease operations in 2020 and 2021, by a further 30 years, to 2051 [Tr.1:11]. The project has been treated as a capital project commencing January 1, 2010 with the start of the definition phase, in which release-quality estimates of the cost will be developed [D2/2/1, p. 17].

4.5.4 Planned spending on the Darlington refurbishment in the Test Period consists of $361.0 million of capital, and $10.4 million of OM&A. By the end of 2012, the cumulative spend will be almost half a billion dollars [D2/2/1. P. 12. Chart 2]. If the Applicant elects not to file for new payment amounts for 2013, the cumulative spend on Darlington refurbishment to the end of 2013 will be $777.8 million in capital [L-10-14] plus perhaps another $50 million in OM&A.

4.5.5 On the other hand, the decision to treat this as a real project effective January 1, 2010 has certain accounting implications. Most notably, the asset retirement obligation and cost for nuclear changes, and it is reallocated between the stations. The net impact of the changes in 2010 was a reduction in costs and therefore revenue requirement of $64.2 million [L-14-35, Attachment 1], and for the Test period a reduction in revenue requirement of $197.1 million.

4.5.6 By the time the project is complete, spending is expected to be as much as $10 billion (in today's dollars), or perhaps as much as $20 billion in 2021 rate base when escalation and interest are factored in.

4.5.7 SEC estimates that, when complete, this project may represent approximately 8% of Ontario's generation capacity.

4.5.8 This project engendered considerable discussion in the hearing, and the following issues appear to have emerged:

(a) What approvals, if any, are being sought from this Board at this time with respect to this project, and what approvals should be given? This involves asking not only about direct or formal approvals, but also implicit or assumed approvals. It also necessarily involves asking what approvals from the Applicant's Board of Directors or shareholder have already taken place, and on what basis.

(b) What spending should be approved, if any, in this proceeding, and what are its implications? This involves asking not only whether spending included in revenue requirement is appropriate, but also about what commitments will be made during that period that will necessitate future spending. Further, it involves looking at what options the Board or the Applicant will have at various future milestone dates to either proceed with the project, cancel it, or modify it, and what potential rate implications may arise.

(c) How should the Board deal with the reduction in revenue requirements in both 2010 and the Test Period arising out of the decision to move to the definition phase of the project as of January 1, 2010? What other implications arise if the Board chooses one or the other approach to this question?

(d) Should the Board allow the Applicant to include CWIP in rate base for this project? What other implications arise if the Board chooses for or against this proposal? (We have dealt with this question in detail in Section 2.2 of this Final Argument.)

(e) To what extent, if any, should the Board consider the implications of the Pickering Continued Operations, the Bruce refurbishment, or new nuclear at Darlington, in determining how to deal with the Darlington refurbishment?

We propose to deal with each of these sub-areas in turn.

4.5.9 ***Approvals Sought.*** Two things were not clear at the outset of this proceeding.

4.5.10 First, SEC and perhaps others did not understand that the Applicant was seeking implicit approval by the Board of the Darlington refurbishment. It is not included in the list of approvals in the Application [A1/2/2]. The only reference there is to the request to include CWIP in rate base, with no mention that doing so would be interpreted by the Applicant to be approval of the project.

4.5.11 The Argument in Chief continues this, saying "OPG is not seeking OEB approval of the decision to refurbish Darlington" [AIC, p. 40; see also Tr.13:80-85].

4.5.12 Second, while we were aware that the Darlington refurbishment meant a $197.1 reduction in revenue requirement [D2/2/1, Chart 1], it was not clear to us and perhaps others that this revenue requirement reduction was, in effect, conditional on the Board giving a green light to refurbish the Darlington NGS.

4.5.13 In fact, the hearing was almost over, and we were still trying to nail down what the Applicant was asking the Board to do. It finally became very clear on Day 13 in the following exchange [Tr.13:87/8]:

> *MR. SHEPHERD: And you would agree with me, wouldn't you, that the Board, in determining whether to say, yes, go ahead and spend this money, and, in addition, to say, yes, include it in rate base, should <u>satisfy itself that the spending you are proposing is reasonable and that the project is likely a good idea?</u> Yes?*

> *MR. BARRETT: Yes, I would agree with that.*
> *MR. SHEPHERD: Okay. If it doesn't, it shouldn't let you put CWIP in rate base?*
> *MR. BARRETT: Nor should it reflect the other adjustments that are shown in chart 1 of Exhibit D2, tab 2, schedule 1.*
> *MR. SHEPHERD: So --*
> *MR. BARRETT: There is a clear linkage between proceeding with the project and these consequent impacts.*
> *MR. SHEPHERD: Oh, absolutely. So the whatever it is, $150 million reduction in revenue requirement that results from the change in the ARC, and that sort of stuff, would have to be reversed?*
> *MR. BARRETT: The 197.1 million, yes. [emphasis added]*

4.5.14 What we take from that is that, in the event that the Board approves CWIP in rate base, or the Board adopts the changes to revenue requirement consequent on the Darlington refurbishment project, absent any clear statement to the contrary the Applicant will treat that as approval of the project by the Board.

4.5.15 We do not believe the Board has sufficient evidence before it to assess whether the Darlington refurbishment project should go ahead. In fact, the Applicant had numerous opportunities during the course of the proceeding to provide that level of evidence, and did not do so. When asked detailed questions about the project, the Applicant's witnesses instead fell back on the mantra that there were still future decision points, and a final decision to refurbish Darlington has not yet been made [Tr.8:86].

4.5.16 (We note in this regard that we have, in reviewing the transcripts, found numerous references to the status of this "decision". Some of them appear to say that the Applicant has decided to proceed with the project [e.g. AIC p. 40), while others appear to say that the decision is still to be made in the future [Tr.8:52,56,70,71,86]. The answers appear to be a continuum from one side to the other, without a consistent pattern.)

4.5.17 From a purely practical point of view, a reasonable person must conclude that the Darlington refurbishment is likely to go ahead. Not only is OPG management apparently firmly onside, but the government has included this as a key part of its newly released Long Term Energy Plan [K16.2] and its Draft Supply Mix Directive to the OPA [K16.3]. Thus, barring a change in the government's position, it is reasonable to assume that this project will go ahead.

4.5.18 On the other hand, both the LTEP and the Directive also say that Bruce will be refurbished, and Pickering Continued Operations will be completed as planned. Neither of those is considered "approved" in the Application in this proceeding, yet both would have material impacts on revenue requirement [Tr.16:8,15,21]. Their LTEP and Directive "status", however, solid that is, is in fact the same as the Darlington refurbishment.

4.5.19 Of primary importance in this respect, though, is that the Board is not being asked to decide, or predict, whether the project will be pursued. If the government, or the OPA, or the OPG Board or Directors, or any other body, makes a decision to "approve" or support the Darlington refurbishment, that is entirely up to them. If those "approvals" are sufficient for OPG to proceed with spending, that is also entirely up to them. This Board is not in fact being called on to say that the project should proceed, or not, and has insufficient evidence on which to base such a decision.

4.5.20 Therefore, whatever the Board decides to do with respect to the costs in the Test Period, or CWIP in rate base, or any other aspect of this project, in our submission the Board should make crystal clear to the Applicant that its decision does not constitute direct, indirect, implied or any other type of approval of the project or any part of it, and no finding of prudence is taking place in this proceeding. It is, in our submission, important that the Applicant understand that, whatever steps the Board takes for the Test Period, the Applicant is entirely at risk for the prudence of the project and the spending related to it.

4.5.21 ***Test Period Spending.*** The Applicant proposes to spend $361.0 million in capital costs [D2/2/1, Chart 2, p. 12] and $10.4 million in OM&A [F2/7/1, Table 7] on the Darlington refurbishment project in the Test Period. The evidence is that, if the project does not ultimately proceed, much of this spending will have been wasted [Tr.8:69].

4.5.22 Those amounts, however, are the tip of the iceberg. At the end of 2012, if the project does not proceed, there will be commitments for further spending then outstanding, and those amounts will be material [Tr.8:87]. There will also be wind down costs associated with the project. All of these amounts are likely lost if the project does not proceed, yet we would expect the Applicant to seek recovery of these costs from the ratepayers.

4.5.23 This goes further. Spending is expected to ramp higher in 2013, as will commitments. By the time the formal decision to actually do the refurbishment takes place early in 2014, it is reasonable to expect that some $1.3 billion dollars or more will have been spent or committed [see L-10-14, p. 1 and Tr.8:87].

4.5.24 There are two problems with this pattern.

4.5.25 First, the relentlessness of the spending may result in the project becoming, in effect, a *fait accompli*. A decision, whether by the Board or by anyone else, about whether to proceed with the project in 2014, for example, has to take into account that a billion dollars plus has already been spent or committed. This reduces the incremental cost to complete the project, and makes it more difficult to say no and effectively waste all that money.

4.5.26 Second, if a decision has to be made to terminate the project, the Applicant will inevitably point to the Board's decision in this proceeding as justification for asking for recovery of the money and commitments to the point of termination [see Tr.8:88]. It will be very difficult for this Board to deny recovery of those amounts, however, significant, because the Applicant will quite legitimately ask why the Board didn't stop them from spending all that money much earlier on.

4.5.27 This would all suggest that the Board should not approve this Test Period spending. The spending is for a project this Board is not being asked to approve. The Board would be acting quite reasonably if it said to OPG "Spend what you like, but we are not going to include it in revenue requirement, and we won't comment on its appropriateness until you come back with a full evidentiary package supporting a real project for us to review and approve."

4.5.28 That having been said, this Board also has to consider its most important longstanding principle: common sense. The project is likely going to go ahead, and some money needs to be spent now to that end. Whatever the reasons for the Applicant being coy about what it is asking the Board to do, it may not be fair for the Board to simply wash its hands of the matter.

4.5.29 In our submission, the appropriate response of the Board in this situation is to accept/approve the capital and OM&A spending in the Test Period, but with three clear caveats:

(a) The Applicant is cautioned to use every effort to minimize the commitments it is making for spending beyond the Test Period, and to take all steps to ensure that the cost of any termination decision would be as low as possible.

(b) In the next payment amounts application, the Applicant should provide a full package of information supporting the project, equivalent to that which would be required for a leave to construct, and should assume that no further spending will be authorized until the Board has reviewed that application. If the Applicant is not prepared to proceed in that fashion, it should obtain a binding legal approval for the project from another source, such as the government, if it wants further spending approvals from the Board.

(c) If the Applicant decides not to return to the Board for 2013 rates, the Applicant is fully at risk for any spending and commitments in 2013 and beyond. The Applicant should believe from this caveat that, unless there are extraordinary circumstances, any such spending will not be recovered from ratepayers.

4.5.30 It is submitted that these conditions, coupled with the actions we have proposed in the next section, will allow the Applicant to move forward essentially as planned, but minimize the size and scope of any downside risk to the ratepayers.

4.5.31 ***Revenue Requirement Impacts.*** The Applicant provides details of the revenue requirement impacts of the Darlington refurbishment project. Although the net impact of the project is $197.1 million, that includes the impact of the CWIP in rate base proposal, $37.9 million, and the OM&A amount, $10.4 million. The other changes, which essentially all relate to accounting changes for nuclear waste and decommission costs, and depreciation lives, total $245.6 million [K16.4, Scenario 3, Line 24]. Of these changes, $50.3 million relate to income tax, which as we have noted elsewhere in this Final Argument, should have zero impact due to available deductions carried forward. Therefore, the net impact of the accounting changes alone is, in our submission, $195.3 million.

4.5.32 In our submission, these accounting changes should not be implemented for the Test Period, and the revenue requirement should be increased by $195.3 million accordingly.

4.5.33 Our rationale for this is neither altruism nor public policy, but rather pragmatism. The "savings" associated with these revenue requirement reduction, while welcome at this time, are also handcuffs that, as with the spending and commitments discussed above, make it more and more difficult to say no to the project if, when the real cost is known, it is no longer the best generation option. In addition to the spending already incurred, and the commitments outstanding at the time of termination, and the project wind down costs, these "savings" would have to be unwound if a termination decision were made [Tr.8:59-60].

4.5.34 Therefore, in our view it is better not to take the windfall at this time, rather than to take it and risk facing, in two or three years, either a massive rate shock, or being forced to accept a no longer economic project.

4.5.35 Consistent with the recommendation that the Board keep its options as open as possible, in our view deferring this benefit until the project is actually proceeding is the appropriate choice by the Board.

4.5.36 There is, however, an implementation question associated with this. The Applicant has already made the accounting change that results in the reduction of these costs. A decision by the regulator not to recognize it in rates does not mean that it will be reversed. It will simply drop to OPG's bottom line. Further, if the project does end up going ahead, there will be considerable value in recognizing the accounting change for ratemaking purposes at the same time as it was recognized by the Applicant for its accounting purposes, i.e. 2010.

4.5.37 To that end, we therefore propose that the Board establish a Darlington Refurbishment Accounting Variance Account, and order that the amount of $195.3 million being recovered in rates in the Test Period as described above be credited to that account. The Applicant will remain whole, because its rate recovery will match its accounting treatment. If the project is terminated, the accounting changes the Applicant will be required to make will be offset by the cash in the account. If the project ultimately proceeds, the ratepayers will be credited with the savings to date, consistent with the Applicant's accounting treatment.

4.5.38 That then leaves only the impact on 2010. In this regard, we have had a chance to review in draft the Final Argument of VECC relating to this issue. We agree with the VECC's analysis of the issue, although we do not agree that their proposed course of action is the best available.

4.5.39 Without repeating the analysis by VECC, it appears clear that the decision to start capitalizing Darlington refurbishment as of January 1, 2010 results in a 2010 "revenue requirement" (i.e. cost calculated on a regulatory basis) impact of at least $64.2 million, plus tax impacts [L-14-35, Attachment 1]. These are essentially the same types of impacts as are included in the $245.6 calculation for 2011 and 2012. We would therefore assume that there would be a further $20+ million of income tax impacts in 2010, but in keeping with our position on the availability of tax deductions carried forward, those income tax impacts would be reduced to zero because the Applicant was not, for regulatory purposes, taxable in 2010. There should therefore be no tax impact for 2010.

4.5.40 The Applicant appears to be taking the position that, although they received a windfall in 2010 from this change in accounting treatment of the project:

> *"There is no variance account in place that would provide for the return of these amounts to ratepayers. Returning these amounts to ratepayers without a variance account in place would amount to retroactive ratemaking. On this basis, OPG believes it is appropriate that it retain these amounts." [L-14-35]*

This would appear to us to be nothing other than relying on a technicality.

4.5.41 VECC has provided a number of alternatives for the Board to consider, and we agree with them that in principle the $64.2 million should be treated as a credit to the ratepayers in either the Nuclear Liability Deferral Account or the Capacity

Refurbishment Deferral Account. However, it is clear that in either case the Applicant will mount a legal challenge against such a conclusion, alleging retroactive ratemaking. While we believe that such a challenge would likely be unsuccessful, it is not the optimum turn of events.

4.5.42 In our view, another approach the Board could take, if it acts quickly enough, would be to declare the Applicant's current payment amounts interim as of December 30, 2010. The effective date of every aspect of the Board's decision in this matter could then still be set at March 1, 2011, as the Applicant has requested, save one item. The Board could make its decision with respect to the Darlington Refurbishment Accounting Variance Account, which we have proposed above, effective December 30, 2010.

4.5.43 The reason why this should solve the technicality is that, for accounting purposes, the actual entries for depreciation and amortization, and accruals for nuclear waste and decommissioning ARO and ARC, etc., take place at the year end of a company. Although entries are often made on an interim basis during the year, especially if companies prepare interim financials, depreciation and similar accruals are charges that are only considered finalized at year end. Until that time, they have not yet occurred. By way of example, if the Applicant determined, on December 15, 2010, not to proceed with the Darlington refurbishment, its 2010 audited financial statements would not record the change in accounting treatment. They would be prepared on the same basis as 2009. The only reason for any disclosure (it would be note disclosure) would be to clarify the inconsistent interim financials issued throughout the year.

4.5.44 It is therefore submitted that the Board should immediately declare OPG's payment amount rates to be interim as of December 30, 2010. In the event that the Board ultimately decides to let the Applicant keep the 2010 windfall, or if the Board concludes that the accounting result we have posited above is not correct, the interim rates designation becomes irrelevant, and there are no negative consequences. Conversely, if the "technicality" relied on by the Applicant is a barrier to the Board reaching a fair result, and this countervailing "technicality" provides a solution, the declaration of interim rates will have had value. In short, it allows the Board to keep its options open while it is deciding this case.

4.5.45 ***CWIP In Rate Base.*** SEC is opposed to the CWIP proposal of the Applicant, for the reasons set out in detail in Section 2.2 of this Final Argument.

4.5.46 ***Bruce Refurbishment, Pickering Continued Operations, and Darlington New Nuclear.*** Since SEC is proposing that the accounting changes associated with Darlington refurbishment not be recognized in rates, it follows that none of these three other major potential impacts should be recognized for rate purposes in this Test Period.

4.6 *Test Period Additions – Nuclear*

4.6.1 Subject to our comments on Nuclear Rate Base in Section 2.1 of this Final Argument, we have no further submissions on the additions to nuclear assets in the Test Period.

4.7 *Pickering 2 and 3 Isolation Project*

No submissions.

5 PRODUCTION FORECASTS

5.1 *Regulated Hydroelectric*

5.1.1 The Applicant advises that, forecast on the same basis as in the EB-2007-0905 application, the hydroelectric production is expected to be 19.9 TWh. in 2011 and 19.8 TWh. in 2012, a total of 39.7 TWh. In this Application, the forecast has been reduced by 1.3 TWh to reflect a forecast by the Applicant of surplus baseload generation (SBG) in the Test Period [E1/1/2, Table 1].

5.1.2 Staff has provided a good summary of the evidence on SBG [Staff Argument, p. 82-84]. We adopt that summary.

5.1.3 SBG is a new addition to the Applicant's forecasting. The effect of including the adjustment of 1.3 TWh. in the forecast is to increase the hydroelectric payment amounts by 3.3%. From a dollar impact point of view, this is about $47.4 million.

5.1.4 SBG is also in a state of considerable flux at the present time. Ontario is adding new non-dispatchable generation of substantial amounts, and closing maneuverable coal plants. This creates the possibility that, in order to keep the system balanced, IESO will have to require the Applicant to spill water at its prescribed hydroelectric facilities. In this possible scenario, the Niagara facilities are treated as the swing resource, because of the flexibility of dumping water over Niagara Falls.

5.1.5 The problem we have is that there does not appear to be any rigorous basis for forecasting SBG. It arises as a result of a fairly complex set of supply and demand factors, all of which are changing, and most of which are highly unpredictable in the Test Period. Neither the Applicant, nor IESO or anyone else, is currently in a position to forecast SBG reliably.

5.1.6 Further, there are two categories of operational production decisions that the Applicant refers to as SBG. In the clearest case, IESO requires the Applicant to spill water to keep the demand/supply balance in line. In an extended case, the Applicant decides on its own account to spill water, perhaps because the price signals from the market indicate that the production has a low value, or for other financial or operational reasons.

5.1.7 We agree with Staff that it is not appropriate to include a reduction in hydroelectric production due to anticipated SBG. The forecast of SBG is not reliable. It could be as little as zero and as high as the 1.3 TWh. forecast.

5.1.8 Instead, we agree with the basic proposal made by Staff [Staff Argument, p. 84] that instead of including this in the forecast, a variance account should be established that captures any actual SBG that arises during the Test Period.

5.1.9 However, we disagree with Staff on what should be categorized as SBG. In our submission, IESO, not the Applicant, is responsible for operating the system and keeping the demand/supply balance in line. If there is a need to spill water, IESO can and will direct the Applicant to do so, creating an SBG situation, and a loss of revenues. In those circumstances, we agree that the lost revenues should be charged to the variance account, to be recovered from ratepayers later.

5.1.10 On the other hand, if the operator of the system is not asking the Applicant to adjust its hydroelectric production for SBG, the Applicant should not be taking it upon itself to do so anyway.

5.1.11 It is therefore submitted that the Board should increase the hydroelectric production forecast by 1.3 TWh., but establish a Surplus Baseload Generation Variance Account. The value of any production foregone because of direction from IESO to cut back hydroelectric production should be charged to that account for future recovery from ratepayers.

5.2 ***Nuclear***

5.2.1 ***Major Unforeseen Events.*** In our submission the production forecast of OPG should be increased by 2 TWh. OPG has presented no evidence to support the inclusion in the forecast of an adjustment for major unforeseen events as presented in E2/T1/S2, Table 1c. Adding this production back into the forecast would have the effect of reducing the two year deficiency by $200 million

5.2.2 The 2 TWh adjustments is arbitrary, duplicative, unsound methodologically, inconsistently applied and counter to the Board's objective of using meaningful benchmarks to incent better performance. SEC notes that this is the first time OPG has included such an "adder" to its forecast.

5.2.3 OPG operates its nuclear fleet as base load generation. Therefore the nuclear forecast neither depends on external factors such as weather, or market demand. This makes the forecast methodology the simple summation of the power that can feasibly be produced by each of the nuclear units. The key variables in this methodology are the unit capability factors, the forced loss rates and the planned outages, including a forecast of extensions to those outages. Notably, two of these variables, unit capability factor, and the forced loss rates, are the subject of benchmarks and targets in OPG's business plan.

5.2.4 To this straightforward calculation OPG then makes two adjustments. The first is a "fleet level adjustment" which OPG describes as an adjustment to recognize the potential for events that are not predictable from a station perspective. This is in addition to the forecast of forced outages, which also attempts to capture unpredictable occurrences. This adjustment reduces the forecast by 0.3 and 0.35 TWh in 2011 and 2012 respectively. Then, a second adjustment of 2 TWh is made for "major unforeseen events". The definition of a major unforeseen event is determined retrospectively by the Applicant.

5.2.5 In our submission the adjustment for "major unforeseen events" is arbitrary. It is simply calculated as some portion of past forecast errors. OPG presents no evidence that past experience is a good predictor or likely to be repeated. In fact it does the opposite. The nuclear plan is replete with programs and initiatives to improve performance. Using the past to predict the future is fraught with difficulties at the best of times (as anyone who has left an umbrella at home knows). It is especially suspect when the past is expressly being repudiated and new systems are being implemented so as to not repeat it.

5.2.6 In fact, this seems to be the view of OPG in other places in the evidence. SEC would draw the Board's attention to its cross examination on OPG's derivation of the forced extension of planned outage forecast in which the panel made clear its position that using past experience would be a bad indicator of the future. In that exchange Ms. Carmichael testified "*..we don't go and add for, say, FEPOs (forced extension to planned outages) from a previous period because they just happen to cover them.*" [Tr.6:55].

5.2.7 The addition of 2 TWh is a duplicative measure to incorporate forecast error. OPG builds into its forecast uncertainty factors in two other places. Exhibit J6.3, for example, shows that more than 50 days of contingency have been built into the forecast for planned outages. Another 0.65 TWh is added for fleet level contingency. In our submission adding yet another contingency dilutes the meaningfulness of the forecast.

5.2.8 The adjustment is methodologically unsound. The figure of 2 TWh is calculated as some subset of a losses of 3.5 TWh that OPG distinguishes after the fact to be split between forced losses and "unforeseen events." In our submission the only difference between a forced loss event and an "unforeseen event" is the magnitude of the problem causing the outage.

5.2.9 In essence OPG is suggesting that the Board accept phony forced loss rates. That there is no real distinction to be made between an unforeseen event and forced losses was made clear in cross-examination:

> *"MR. SHEPHERD: What I am trying to get at is that the major unforeseen events is really an FLR problem; right?*
> *MS. CARMICHAEL: It is quantified -- when it comes through actually, in the actuals, it is quantified as an FLR for the plant." [Tr.6:77]*

5.2.10 There is a clear inconsistency between the forecast used for nuclear production and the forecast proposed by OPG for the purpose of calculating prices. This is clear and was put forward by Ms. Carmichael: " *We told our board that for OPG's submission purposes, we would – we want the target to be 48.9 and 50, but from a nuclear perspective, we were going to stretch ourselves to 50.9 and 52*". [Tr.6:84].

5.2.11 What this sounds like, in fact, is that the Applicant had a real forecast, and then they had an adjusted forecast for regulatory ("submission") purposes.

5.2.12 There is also an inconsistency between the adjustment and the proposed budget. OPG does not include the cost of outages related to the 2 TWh adjustments in its OM&A budget [Tr.6:10].

5.2.13 If the Board accepts the proposed methodology then in our submission there is significantly less meaning and relevance to the benchmark and targets for forced loss rates.

5.2.14 The evidence is clear that OPG intends to operate to produce 50.9 and 52 TWh in 2011 and 2012. Those figures, then, should be the production forecast for nuclear.

5.2.15 ***Darlington Forced Loss Rate.*** In our submission another adjustment should be made to the forecast to reflect a change to Darlington's Forced Loss Rate (FLR) from 1.6 to 1.0. This is the average of the four years and removes the anomalous forced loss rate of 3.2 in 2006 and would add between $7 and $10 million to the revenues during the test period (L/T12/030; J3.2).

6 OPERATING COSTS

Regulated Hydroelectric

6.1 *OM&A Budget – Regulated Hydroelectric*

No submissions.

6.2 *Benchmarking – Regulated Hydroelectric*

No submissions.

Nuclear

6.3 *OM&A Budget - Nuclear*

6.3.1 In our submission the Darlington OM&A budget should be reduced to meet a non-fuel operating cost target of $25.10/ MWh. They appear to have the ability to do so. For example, the minimum complement at Darlington is 475 people (J5.3). The proposed FTE for the units is 1691 and 1692 for 2011 and 2012. It would appear to us that there is room to manage staffing.

6.3.2 Achievement of the $25.10/MWh target would reduce OM&A by approximately $40 million per year.

6.3.3 SEC recognizes that this reduction is a significant amount for a unit with good operating performance. It is because these units are operated so successfully that it offers the opportunity for further improvement.

6.3.4 In making this submission SEC notes that it has refrained from making any submissions on reducing operating costs in respect to the Pickering units. This is not because opportunities for savings do not exist. Clearly they do. OPG gave evidence that it thought there were likely more opportunities to make savings at the Pickering units. In our view the best approach to cost control with respect to the Pickering units is for the Board to develop a long-term goal for these units to fall below production costs of $40 MWh.

6.3.5 In our submission Nuclear base OM&A should also be reduced by $10 million, or 1% of labour costs to reflect the difference between the standardized labour rates used for calculating the budget, and the actual labour costs. This labour price variance account has historically overestimated labour component of the OM&A budget [Tr.5:53].

6.4 *Benchmarking - Nuclear*

6.4.1 Two questions were asked in respect to nuclear benchmarking methodology.

6.4.2 ***Methodology.*** The first question was whether the benchmarking methodology is reasonable. In our submission the ScottMadden methodology is sound, and OPG should be commended for a large positive step in improved benchmarking.

6.4.3 However, the methodology could be made more meaningful with some refinements, such as:

(a) The methodology does not make any refinements to the EUCG group of data.

(b) There is no distinction as between CANDU and PWR units.

(c) Outlier data is not removed from the study group and no adjustment is made for the size of units.

(d) No attempt is made to consider age or refurbishment status of comparator units.

This lack of refinement impairs the value of some benchmarks and allows too generous of targets to be set.

6.4.4 Refinements to consider significant differences in CANDU and BWR/PWR technologies do not need to be about **"***debating whether or not they're contributing five dollars or ten dollars or six dollars***"** [Tr.3:41]. The fact is that the these differences are already considered in the total cost benchmark proposed by OPG and ScottMadden. This benchmark includes fuel, which the evidence shows is clearly a cost advantage for CANDU reactors. By using the total cost comparison there is an implicit assumption that this cost advantage is offset by an equal amount of cost disadvantage. No evidence is given to show that this is the case. It is just as possible that the cost fuel cost advantages of CANDU do not compensate for operating cost disadvantages vis-à-vis BWR/PWR technologies. Or it could be the converse. Until the issue is investigated further little reliance can be put on the total operating cost benchmark. In our submission the Board should require the Applicant to put its focus on the non-fuel operating cost benchmark.

6.4.5 It is logically inconsistent for OPG to make both the argument that its CANDU nuclear facilities are inherently more costly to operate (F5-1-1 pg 124) while also stating that it is not possible to identify and quantify these costs [Tr.2:158-160; Tr.3:84-185]. In our submission the Board should not be persuaded that OPG's target benchmarks should be more generous due to unspecified differences in technology, age or size of plant.

6.4.6 In our submission OPG should improve benchmarking by undertaking a study of the major areas of cost difference between CANDU and PWR/BWR nuclear generating facilities. This study should consider the material differences in cost of technologies and should consider both the cost advantages of CANDU (for example in fuel and on-line fueling) and the cost disadvantages. The next phase of benchmarking should also include quantitative analysis testing as to whether there is a relationship between size and age of units and their benchmarks.

6.4.7 OPG could immediately improve the comparability of all the benchmarks-to-target for Darlington by eliminating all EUCG comparators which produce power at more than $40/MWh. This would eliminate Pickering A and B from a comparison with Darlington.

6.4.8 The evidence is clear that Pickering A and B are significantly different from the vast majority of comparators. OPG argues that this is due to their technology, age and size of units. We note that no evidence was provided that there were not other units in the EUCG that were of similar size and age, if not technology.

6.4.9 Thus, Pickering A and B should not be used to benchmark Darlington, and should not themselves be benchmarked against the same units that are Darlington comparables. Instead, in our submission OPG should develop a plan to achieve a target for the non-fuel cost benchmark for the Pickering units of $40.00/MWh or below. This plan should be presented in the next proceeding.

6.4.10 ***Results.*** The second question raised in the issues list was whether the benchmarking results and targets flowing from those results are reasonable. ScottMadden study provides a comprehensive number of benchmarks under the categories of safety, reliability and value for money. While all these benchmarks can be useful for OPG's planning and operations, in our submission not all are of use in the Board's consideration of setting prices.

6.4.11 Indices, such as the WANO and Nuclear Performance indices, are aggregates of safety, reliability and value for money measurements. These indices can be academically interesting in respect to considering OPG's performance vis-à-vis other nuclear operators. They are, however, less useful in determining whether OPG is meeting performance targets established for the purpose of setting prices.

6.4.12 Safety benchmarks are certainly useful for the management of OPG . Compelling evidence was given as to there use in human resource management [Tr.3:176]. Safety is an important aspect of any company and is especially important when operating and monitoring a potentially dangerous technology. However it is a benchmark that is not particularly relevant to the objective of economic regulation. With respect, it is not the Board's responsibility to make determinations as to whether safety is adequate at

OPG. This is the responsibility of OPG management and its safety regulator, the CNSC. In our submission OPG should aim to have the highest unit production with the lowest generating costs possible while meeting the safety requirements established by its management and monitored by the CNSC.

6.4.13 Reliability is clearly an area linked closely with output. With respect to reliability we submit the Board should primarily rely on the Forced Loss Rate and the Unit Capability Factor benchmarks. Nuclear Performance is an aggregate indicator, but on-line elective or corrective maintenance backlog benchmarks are only indicative in nature, in that they are ultimately subsumed in either the forced loss rate or unit capability benchmarks.

6.4.14 In our submission the capital cost per MW DER is a flawed benchmark due to the fact that OPG has a higher capitalization threshold policy than all of the EUCG group. It is our understanding that the costs related to this benchmark are subsumed in the non-fuel operating cost benchmark.

6.4.15 In respect to value for money benchmarks our submission is that the Board should rely on the non-fuel operating cost benchmark. OPG states that “performance in non-fuel operating cost per MWh drives the majority of OPG financial performance” (F5-1-1, pg 123).

6.5 ***Response to the Nuclear Benchmarking Report***

6.5.1 With the exception of our submission in respect to a lower non-fuel operating cost for Darlington, SEC submits that OPG has responded appropriately to the ScottMadden Benchmarking report. The gap based planning demonstrates that the company is willing to use benchmarks to improve performance.

6.5.2 In our submission Darlington’s non-fuel operating cost targets for 2011 and 2012 are too conservative. There is no evidence to support inflation of the 2008 average benchmark of $25.10 MWh. A more appropriate benchmark would be to apply an inflation indicator of 2% per annum as a proxy for the CPI for 2009 and 2010. Further submissions on this issue are made under issue 5.1.

6.5.3 In our submission in the future OPG should more closely link compensation and bonus to the key reliability and value for money indicators. The benefit of having a close link between compensation and targets was also supported by ScottMadden, OPG’s benchmark advisor [Tr.3:161].

6.5.4 In our submission the logical next step in benchmarking should be an objective of eliminating detailed reviews of the operating costs and revenues in price setting applications. Ideally the Board should establish non-fuel operating cost benchmark targets from which operating costs would follow. Similarly, production and hence revenues would be calculated based on benchmarked forced loss rates and unit capability targets. Before this can be done OPG must refine the benchmark cohort in the manner suggested by SEC.

6.6 *Nuclear Fuel Costs*

6.6.1 There are two issues that arise in the context of nuclear fuel costs:

(a) is the strategy being employed by the Applicant prudent, and is it reasonable to continue it in the Test Period, and

(b) should the Nuclear Fuel Variance Account be continued in its current form?

6.6.2 Staff has presented a thorough review of these two issues [Staff Argument, pp. 53-59]. Subject to one additional comment below, we agree with Staff's analysis, and their conclusions.

6.6.3 Our one additional comment relates to the Applicant's claim that it is important to minimize price volatility [AIC, p. 26]. As was seen in cross-examination by SEC [Tr.5:72-82], the nature of the fuel production process already provides a robust smoothing effect, such that the impact of uranium market prices on the actual cost of fuel bundles used for generation is heavily muted. In addition, there is a variance account, which also has a smoothing effect.

6.6.4 This situation reminds us of the "Risk Management" program that Enbridge Gas Distribution carried out on gas commodity purchases. At a relatively high cost, Enbridge adopted a strategy of minimizing price volatility. The result was that the average cost of system gas was higher, and the spending on risk management was essentially wasted, all with minimal impact on volatility. The Board ultimately shut the program down [EB-2007-0606/615].

6.6.5 The problem, it seems to us, is that procurement programs that attempt to "beat the market" rarely will achieve that result, and programs to reduce volatility will necessarily result in higher costs in most cases. There is a market premium associated with shifting price variance risk to others. If there is value in shifting that risk, it is sometimes worth the premium paid. Where, as here, volatility is not a problem, the costs of shifting price variance risk are not justified.

6.6.6 Therefore, in our submission the Board should require the Applicant to develop a plan to change to a market-based uranium procurement program, and in developing that plan quantify the savings that can be achieved by doing so.

6.6.7 With respect to the Nuclear Fuel Cost Variance Account, we agree with the two recommendations of Staff, i.e. inclusion of working capital impacts in the account, and an asymmetrical cost-sharing component to incent cost minimization by the Applicant.

6.7 *Pickering Continued Operations*

6.7.1 SEC agrees with Board Staff [Staff Argument, p. 64] that the benefits of Pickering B Continued Operations could be significantly overstated.

6.7.2 In our submission, the Applicant should also be advised to curtail further spending on this project until an independent analysis of the benefits has been carried out, and the Applicant is ready to commit to completing the project. The Applicant's expenditures before that analysis should be considered to be "at risk" in a subsequent prudence review by the Board.

Corporate Costs

6.8 *Human Resource Related Costs*

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 ***How Many People?*** We would like to provide an analysis of the increases in headcount or FTEs for the Applicant, but it is clear that the Applicant does not have comparable information available to do such an analysis. As can be seen, for example, with J9.6, the Applicant persists in using a different metric for past data compared to forecast data, with the result that it is not possible to compare # of people forecasts to past actuals [Tr.4:80].

6.8.3 There are many reasons for choosing different metrics, but in our submission the Applicant must recognize that it is a regulated entity, and critical information should be available in a manner that is both accessible and comparable. Therefore, it is submitted that in the future the Applicant should be required to file compensation information, in the format of Appendix 2K used for electricity distributors, with comparable information for all past and future years that may be relevant.

6.8.4 ***How Much Should They Be Paid?*** The Applicant has determined that its employees, except for management employees, should be benchmarked to the 75^{th} percentile relative to their peers. In fact, on average a selected group of OPG occupation groups, chosen by OPG staff without independent review, averaged 6% above the 75^{th} percentile [F4/3/1, p. 30, Chart 11].

6.8.5 There was extensive cross-examination in the hearing on this issue and related matters. The Applicant appears to be convinced that, not only is it reasonable to pay at these high levels, but they are essentially powerless to change this, in the face of their high level of unionized workers. Their sense of inevitability is so great, in fact, they indicate they don't even want to know how their unionized workers compare to other companies. The information, they say, would be useless [Tr.9:92].

6.8.6 This is not the first time that this Board has had to deal with a regulated entity that claims to be unable to manage the wage expectations of their unions. This issue has arisen in Hydro One and other cases. What the Board has seen, we believe, is that if it sets limits, and backs them up with revenue requirement implications, regulated entities respond favourably.

6.8.7 In this case, it is submitted that it is not good enough for the Applicant to say "I can't" when faced with high compensation levels for unionized workers. In this respect, we believe that there is a longstanding relationship between the normal desire of utilities that the Board not try to manage their affairs, and the concomitant responsibility on the part of utility management to deliver just and reasonable results. The Board should set the results to be achieved. OPG should then find a way to deliver those results.

6.8.8 In this case, we believe that the Board should reduce the revenue requirement for each of 2011 and 2012 to reflect the start of an adjustment from 75^{th} to 50^{th} percentile. The question, given the evidence, is what that adjustment should be.

6.8.9 The Applicant has estimated that the annual revenue requirement impact of reducing a sample (28%) of its unionized positions to the 50^{th} percentile would be $37.7 million [J8.6]. From that figure, we extrapolate a total for all of their unionized employees, based on that sample, of $134.6 million [$37.7/0.28]. In the absence of better evidence, we believe that is a reasonable starting point.

6.8.10 It is, in our view, unfair to ask the Applicant to get to 50^{th} immediately. It has union contracts coming due both soon, and early in 2012, so its opportunity to take action is not unlimited. Although those timing restrictions are ones that the Applicant accepted voluntarily in signing the contracts, it is in fact the current reality. Further, even when the contracts are up for renegotiation, it is unlikely that a full move to the target level can happen in one shot.

6.8.11 In order to light the fire under management, in the same way that the Board successfully motivated them in the Original Decision, we propose that the target be 25% of the way to the goal in 2011, and 50% of the way to the goal in 2012. This would involve reductions to unionized compensation in 2011 of $33.7 million, and in 2012 of $67.3 million, for a total reduction of $101.0 million. This should be allocated to capital and OM&A on the same percentages as unionized compensation is allocated between them in the Application.

6.8.12 In other areas of this Final Argument, we have suggested reductions in OM&A and capital spending. The adjustment noted above is not intended to be additional. To the extent that it is already achieved through the specific reductions otherwise proposed, it should not be double-counted.

6.8.13 ***Benchmarking of Unionized Staff.*** The proposed adjustments provide an interim approach, but in our view the Applicant should have more detailed information allowing it to benchmark its total compensation to its peers. Asked about this, the witnesses for OPG did not believe that the six or seven figure cost of such a study would be warranted for the limited benefits of having the information [Tr.9:92].

6.8.14 We agree with Board Staff [Staff Argument, p. 68] that for a company that is planning to spend $2.8 billion on compensation in the Test Period, this cost of having good information on fair compensation levels is well worth the investment. We therefore believe that the Board should direct the Applicant to carry out a full total compensation benchmarking study for its unionized positions, and file it in its next payment amounts application.

6.8.15 ***Incentive Compensation.*** Annual incentive compensation at OPG is low relative to other companies, a fact on which ScottMadden was critical [F5/3/1, p. 19]. Further, the Arnett Report [K9.3, p. 19] recommended that incentive compensation be increased.

6.8.16 Notwithstanding these inputs, the Applicant admits that it has not implemented any changes to the level of incentive compensation [Tr.9:74] for management. In addition, the Applicant has made clear that, while it is important to shift the corporate culture to a more performance-based approach for unionized employees as well as non-unionized [Tr.9:85], increasing incentive pay for unionized employees is essentially a non-starter [Tr.9:86].

6.8.17 In our view, the Applicant should be encouraged to push ahead with increases in the percentage of incentive compensation for all employees, and should be directed to report back to this Board in its next payment amounts application to show the progress it has made in improving this metric.

6.8.18 ***Licence Retention Bonus.*** Finally on compensation, 221 employees of the Applicant are paid a bonus of 15-28% of their base salary as a licence retention bonus [Tr.9:93]. The impact of this on annual compensation cost is $7 million [Tr.9:94].

6.8.19 In our submission, the value of this special bonus, which does not appear to have a comparable in any other regulated utility in Ontario, has not been demonstrated. Therefore, it is proposed that the Board reduce total compensation costs by $14 million for the Test Period, allocated all to nuclear, and allocated between capital and OM&A on the same basis as nuclear unionized compensation is currently allocated in the Application.

6.9 *Centralized Support and Administrative Costs*

6.9.1 ***Regulatory Affairs.*** We have read and support the analysis by Board Staff of the forecast regulatory expenses of the Applicant for the Test Period. We agree that revenue requirement should be reduced by $5.7 million to reflect more reasonable estimates.

6.10 *Response to HR Benchmarking Information*

6.10.1 Please see our submissions under Section 6.8 above.

Other Costs

6.11 *Other Operating Costs*

6.11.1 ***Depreciation.*** We have elsewhere in this Final Argument proposed that the Board not accept the reduction in depreciation and other costs associated with the assumption that Darlington will be refurbished and its life extended to 2051 [see Section 4.5].

6.11.2 In addition, we agree with Board Staff [Staff Argument p. 77] that the Applicant should be ordered to carry out a full, independent depreciation study and file it for review in its next payment amounts application.

6.11.3 There are several reasons for this latter recommendation:

(a) We have seen from this Application that revenue requirement for this highly capital intensive business is sensitive to depreciation assumptions.

(b) The Darlington refurbishment, which will go ahead or not, may have a significant impact on depreciation going forward.

(c) The lives of the Pickering A and B units are also the subject of some controversy. The Board had to take almost a full day to deal with “scenarios” evidence, which was essentially a review of the accounting impacts of various assumptions about in-service lives of some generating stations.

(d) The completion of the Niagara Tunnel may have its own depreciation assumptions, including those directly relating to the new asset, and the impacts of that asset on the lives of other assets.

(e) The government has announced its intention, in the Long Term Energy Plan [K16.2] to include refurbishment of Bruce NGS in its future plans. Some of the impacts we are already seeing from Darlington refurbishment may arise if Bruce is to be refurbished as well.

(f) IFRS has different rules for depreciation, and the interaction of those rules with the many changes in the Applicant's assumptions is likely to be complicated.

6.11.4 Given these facts, it appears to us that this is an opportune time to carry out an independent depreciation review. In addition, if, in the end, some form of formula-based rate setting is implemented in the next few years, having appropriate depreciation rates and policies in place prior to that time will be also be important.

6.11.5 ***Nuclear Insurance Costs.*** The Applicant has proposed to increase the forecast nuclear insurance costs to $11.3 million in 2011 and $13.4 million in 2012 [F4/2/1, Table 1]. The average nuclear insurance cost for the four years 2007 through 2010 is only $7.8 million. The difference appears to be the impact of Bill C-15, a bill currently in Second Reading before Parliament [J10.12], which would amend the Nuclear Liability Act and thus increase the cost of insurance.

6.11.6 This is not the first time that an amendment to the Nuclear Liability Act for this purpose has been proposed. Previous bills have been put forward by the current government, but have not been passed [K15.1, p. 3].

6.11.7 It is submitted that, until Bill C-15 is passed, if at all, it is premature to assume that nuclear insurance costs will go up. We believe that the appropriate cost level to use is the average for the last four years, $7.8 million per year. This would result in a reduction in nuclear revenue requirement of $9.1 million in the Test Period ($11.3 million plus $13.4 million less two times $7.8 million).

6.11.8 ***Income Taxes.*** As set out in detail in Section 10.2 of this Final Argument, in our submission there are regulatory tax deductions available for the Test Period that are more than sufficient to reduce taxable income for ratemaking purposes to zero in 2011 and 2012.

6.11.9 Therefore, in our submission the provision for income tax, and the gross up related to it, should be removed, and the revenue requirement for the Test Period reduced accordingly. We estimate that this reduces the revenue requirement by $262.6 million.

6.11.10 ***PST vs. HST***. It appears that the revenue requirement impact of the HST input tax credits is a reduction of $6.0 million per annum [JT1.9], not the amount of $5.0 million included in the Application [F4/2/1, p. 24].

6.11.11 In our submission, the revenue requirement for the Test Period should be reduced by

$2.0 million, representing $1.0 million underforecast of this saving for each of the two years.

6.11.12 Subject to the above comments, we have no submissions on Other Operating Costs.

6.12 ***Asset Service Fees***

No submissions.

7 OTHER REVENUES

7.1 *Regulated Hydroelectric*

No submissions.

7.2 *Nuclear*

7.2.1 In our submission the net revenues from the sales of any surplus heavy water should be an offset to OPG's 2011 and 2012 revenue requirement .

7.2.2 It is the position of the Applicant that the surplus heavy water was not an asset in rate base at the time of regulation of OPG in 2005. OPG also suggests that O. Reg. 53/05 precludes the Board from dealing with the revenues from the sale of these assets. Contrary to the suggestion of OPG, nothing in O. Reg. 53/05 precludes the Board from dealing with this matter.

7.2.3 OPG's proposal for heavy water sales is considerably different from that proposed in EB-2007-0905. In that proceeding OPG made the point that it was "a world leader in heavy water sales and services." (EB-2007-0905 G2/T1/S1, p.3). It did not suggest at that time that the activity was outside of the Board's purview to consider.

7.2.4 We agree the assets in question are not in rate base and have not been part of OPG's rate base since 2005 when OPG became regulated by the Board. The evidence at L10.6 clearly shows that Ontario Hydro wrote off $1.203 million of this asset in 1996. However, the fact that OPG has an asset for sale means that the asset remained on the books of OPG, albeit at a value of zero dollars. It remained an asset of the nuclear operations and the costs of storing and maintaining the asset continue to be incurred.

7.2.5 On the day the Board began regulating OPG any number of assets of OPG would have been fully depreciated. Other assets like vehicles and office equipment would have been near the end of their life. Under the principle being espoused by OPG the salvage value of any these asset should accrue to the shareholder. By extension the Board only regulates the undepreciated portion of assets that were in rate base at the time of regulation in 2005.

7.2.6 In our submission such an outcome is not only wrong logically, it is also unfair. Ontario's electricity ratepayers were required to pay for this heavy water. They should not be excluded from benefiting from its sale value.

7.3 *Bruce NGS*

No submissions.

8 NUCLEAR WASTE MANAGEMENT AND DECOMMISSIONING LIABILITIES

8.1 *Methodology*

No submissions.

8.2 *Revenue Requirement Amount*

No submissions.

9 DESIGN OF PAYMENT AMOUNTS

9.1 *Payment Amounts*

No submissions.

9.2 *Hydroelectric Incentive Mechanism*

9.2.1 No submissions.

10 DEFERRAL AND VARIANCE ACCOUNTS

10.1 *Nature and Type of Costs Recorded*

10.1.1 Our comments relating to this issue are incorporated into our analysis of the amounts recorded in the accounts, in Section 10.2 below.

10.2 *Amounts Recorded (Tax Loss, Bruce Lease, and Nuclear Liability Accounts)*

10.2.1 ***General.*** We have limited our comments below to three accounts for which clearance is proposed: the Tax Loss Variance Account, the Bruce Lease Cost Variance Account, and the Nuclear Liability Deferral Account. We will deal with each of them in turn.

Tax Loss Variance Account

10.2.2 In the following section, we conclude that the Applicant has taken tax deductions prior to April 1, 2008 totaling $1,660.4 million that should be available for deduction by the ratepayers, as the ratepayers will be bearing those costs ("benefits follow costs").

10.2.3 As a result, there should be no regulatory tax liability for the first test period (April 1, 2008 to December 31, 2009), nor for calendar 2010, and there will be none for 2011 or 2012. Rates for those periods should not include any provision for tax payable. The recovery of the 2008/9 mitigation amount of $168.9 million also does not need to be grossed up, because it too is sheltered by those previously taken deductions that rightfully should accrue to the benefit of the ratepayers. After all of those deductions have been used up, there would appear to be $450-500 million of tax deductions still available to shelter taxable income for the period 2013 and beyond.

10.2.4 We therefore propose that an amount of $168.7 million, representing the only appropriate balance remaining in the Tax Loss Variance Account, and without any gross up, be recovered from the ratepayers over the period 2011 through 2014 as proposed by the Applicant.

10.2.5 ***Introduction.*** The difficulty in dealing with the calculation of the Tax Loss Variance Account ("TLVA") is that it is full of complications, and mired in details, each connected with other details in a circular, daisy chain of interrelationships between the facts. It is a challenge to organize it in a reasonable way.

10.2.6 Further, the Reply Argument of the Applicant will certainly "attack the examples" on the basis that the devil is in the details, causing any attempt at simplification to once again get mired in complexity. (It is the unfortunate result of the sequence of written arguments, in this and virtually every other contested proceeding in any tribunal, that the adjudicator doesn't get the opportunity to have everyone in the same room, with continued back and forth until all arguments and points of view are thoroughly visible.)

10.2.7 In our view, a mechanistic approach to this account, trying to parse the words of previous decisions as lawyers so often do, runs the risk of missing the big picture. What the Board seeks to do, of course, is to get the right answer, but assuming that the right answer can be found in fine interpretation of the words of previous panels may be ill advised. Those previous panels did not have all of the evidence that this panel has, so their conclusions may not have been as precise on specific elements, and in any case an interpretation of their words in a vacuum may or may not reveal what they intended in the context of the much more complete evidence currently before this Board.

10.2.8 To avoid those concerns, we therefore start this analysis with the relevant principles, the complications added to those principles by the unique situation of the Applicant, and a careful look at the question this Board panel must resolve. At that point, we can turn to the past decisions and interpret them, i.e. in light of the evidence and the principled goal that should be achieved in the end.

10.2.9 ***Timing Differences.*** The general principle that the Board and all parties appear to agree [see, e.g. Tr. 14:85] is applicable to tax deductions is “benefits follow costs”. This means, simply, that if the ratepayers bear a cost in their rates, then any tax impacts that flow from that cost accrue to the ratepayers as well. The converse is also true. If the shareholder bears a cost, then the tax benefits associated with that cost do not accrue to the ratepayers; they accrue to the shareholder.

10.2.10 We deliberately pause at the start, therefore, to note that our entire argument on this issue turns on this principle. This is the key to our submissions:

> **If “benefits follow costs” means, in the context of recovery of taxes, that if a cost is borne by the ratepayers, they get any tax benefit associated with that cost, the logic of our argument below is inescapable. If that principle is not correct, then we are wrong.**

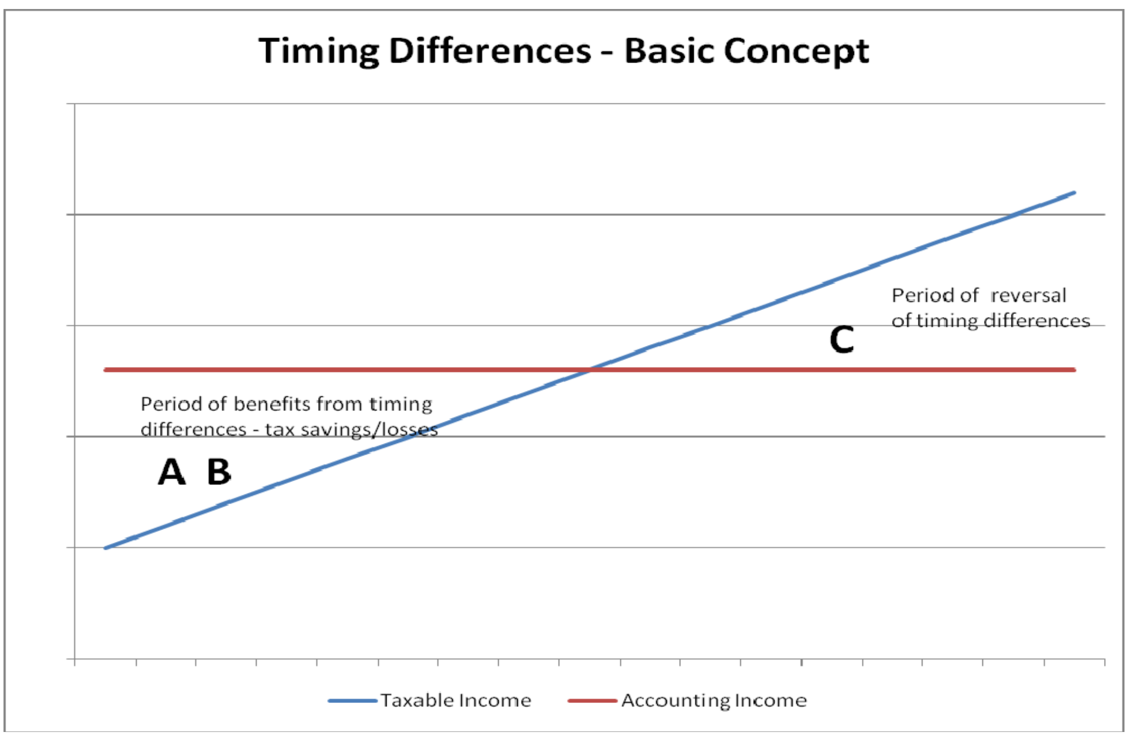
There is no middle ground, and there is no compromise. If the premise is true, the result MUST follow. This is our whole argument in a nutshell, and it is, frankly, no more complicated than that.

10.2.11 It is critical to note that **this has nothing to do with tax losses.** Whether a utility has net taxable income, or net tax losses, the tax benefits associated with costs borne by the ratepayers should always go to the ratepayers.

10.2.12 The reason this is important is the income tax concept of timing differences. Under the Income Tax Act, deductions in any given year to calculate taxable income are not necessarily the same as costs incurred for accounting (or ratemaking) purposes. While the total amount that is tax deductible in respect of any given expenditure is almost always exactly the same as the total amount that is eventually expensed for accounting purposes, the timing of the tax deductions is often not the same as the timing of the accounting expense.

10.2.13 The most common example is accounting depreciation/amortization compared to the tax system's capital cost allowance (CCA). Assume an asset that costs $1,000,000 and is expected to have a five year life. For accounting purposes, it is likely to be charged as an expense (through annual amortization) at a rate of $200,000 a year over five years. The entire cost is expensed, but not all at once. It is quite common for the tax deduction, however, to be $500,000 in year one and $500,000 in year two. The additional $300,000 in deductions in each of the first two years means that taxes are lower than they would be otherwise. In years three through five, taxes are higher to make up for it. This is called a timing difference

10.2.14 Under the tax system in Canada, timing differences usually favour the taxpayer. That is, usually (but not always) the tax system allows amounts to be deducted for tax purposes earlier than they can be deducted for accounting purposes [see Tr. 14:75]. This can be illustrated graphically by the following (Figure 1):



10.2.15 The above graphic shows the impact on taxable income of any given expenditure in which there is a timing difference. In the early years, there is a tax saving (the "benefit"), followed in the later years by a tax cost. The benefit is illustrated by the area "AB" on the left hand side. All other things being equal, area "C" on the right hand side is an equivalent tax cost that offsets the benefit.

10.2.16 This kind of pattern is also called, in tax policy circles, a "tax expenditure", because these timing differences are generally intentional. Government tax policy allows taxpayers to front load their tax deductions, and thus save tax dollars, as a way of providing economic stimulus and incenting long term spending. Many businesses see this as a type of interest-free loan of tax dollars, helping to fund their business activities and/or capital acquisitions.

10.2.17 ***Regulatory Treatment of Timing Differences***. It is well known that accounting rules require the calculation of tax expense as if all of accounting income were taxable, i.e. on an accrual basis. Timing differences must be ignored. This is the reason why financial statements have both current and future tax amounts. Although there is a tax benefit because of the timing difference, financial statements must recognize that sooner or later the full tax will (at least in theory) have to be paid.

10.2.18 The Board, and many other regulators, while generally basing rates on accounting income, have not applied the accrual rules to tax expense. Instead, the Board uses the "taxes payable" method, in which essentially the tax benefits of timing differences for early deductions are enjoyed by the ratepayers in the form of reduced rates. Of course, later the tax cost associated with those previous benefits is also borne by the ratepayers.

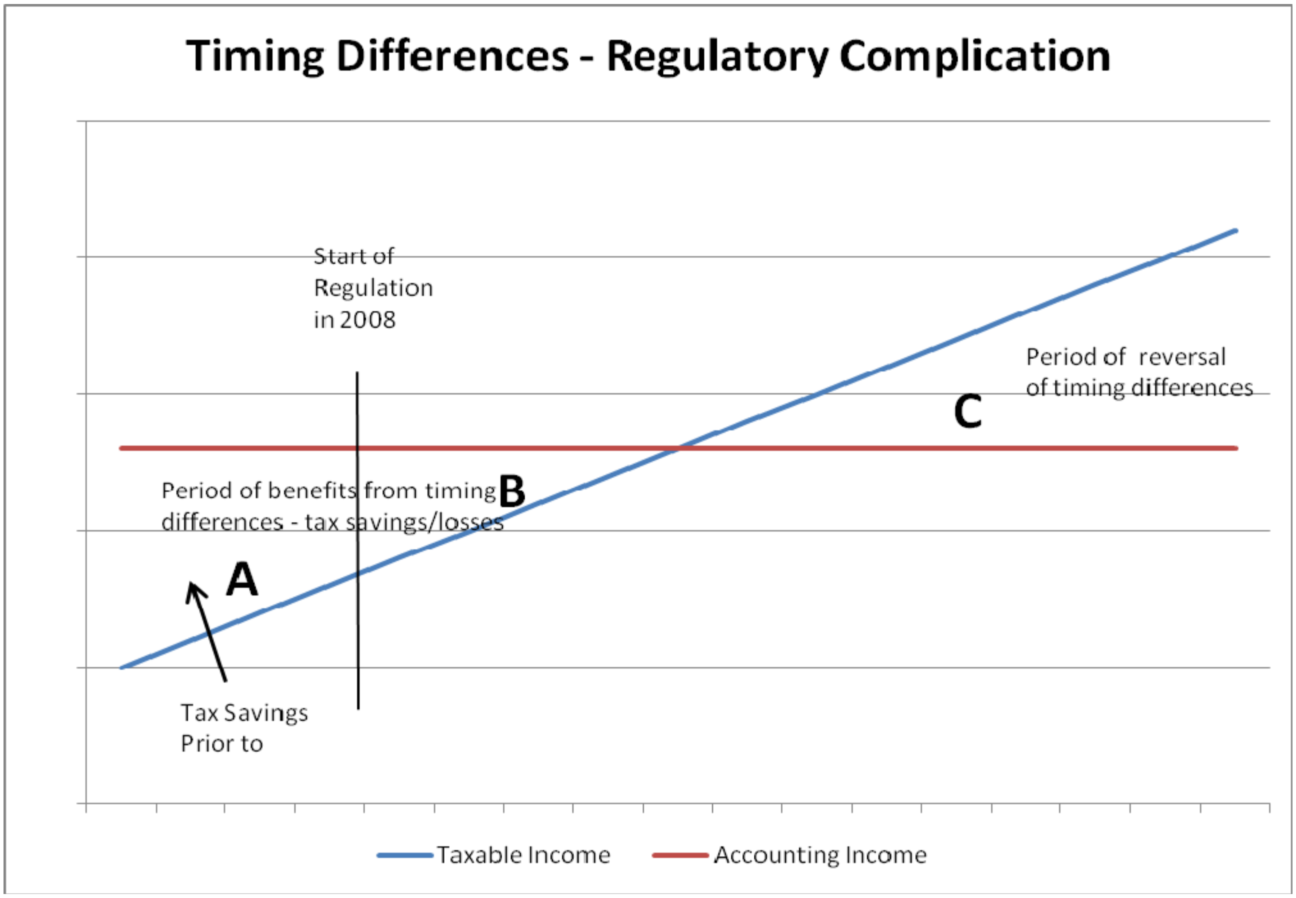
10.2.19 There is a clear and compelling logic to this. The government provides a tax incentive for certain types of spending, so that the upfront cost of that spending will be reduced. Ratepayer funds are being used to incur that spending. The amount the ratepayers pay should be net of the incentive that is specifically designed to reduce the net cost. The Board has asked: "Who should get the incentive?", and has answered "Those who are bearing the cost". This is not controversial, and has been unchallenged Board policy for many years.

10.2.20 In the context of this proceeding, it is critical to note that the "incentive" is the ability to reduce taxes early. It is the timing difference itself that is the incentive, i.e. it is not <u>whether</u> you get the deduction, but <u>when.</u> As we will see later, this can and should assist the Board in determining when tax expenses in rates should be reduced for timing differences.

10.2.21 Of course, the other part of this equation is that the tax cost eventually catches up with the benefits. In the simplest case, as assets get older the tax deductions they generate are less than the accounting expenses recognized. Taxable income is then higher than accounting income. In those cases, ratepayers bear tax in their rates on what appears to be phantom income. It is not. It is simply income that was recognized for accounting purposes earlier than for tax purposes.

10.2.22 ***The OPG Complication.*** This is all fine, and benefits the utilities and the ratepayers alike. In the normal situation, as set out in Figure 1, there is a natural flow of tax benefits and costs, a closed system in which the totals are all the same and the balance is, at least in theory, always zero at the end of the process.

10.2.23 However, the situation changes when a company that was not rate regulated, becomes rate regulated, as is the case with OPG. Then, the pattern over time is broken, and the potential arises that tax benefits will be enjoyed by the shareholder in the pre-regulation period, but the balancing tax costs will be borne by the ratepayers in the post-regulation period. This can be shown graphically as follows (Figure 2):



10.2.24 Note that this is the same graphic. All that has happened is that the former area of tax benefits, AB, has been split up into A (pre-regulation) and B (post-regulation). A + B should still equal C. However, if the Board does not ensure that timing differences enjoyed pre-regulation (area A) are returned to the ratepayers, the ratepayers will end up bearing excess tax costs (area C) that are greater than the earlier tax benefits (area B) they received. .

10.2.25 This would not be fair, and would not follow the "benefits follow costs" principle.

10.2.26 ***So What is the Question?*** In our submission, the Board has determined in the Review Decision that the rates for the 2008/9 test period were understated because the benefits follow costs principle was not followed in the Original Decision. The TLVA was set up to provide a vehicle to fix that problem. This Board panel's challenge is to determine what the tax costs and benefits would have been (and therefore what the rates for the previous test period would have been) had the benefits follow costs principle been followed correctly. To the extent that the rates were lower than they should have been, there is an amount owing from the ratepayers to the utility.

10.2.27 Of course, the first of the complications arises right away. The basic paradigm is that the tax benefits go to those who will ultimately bear the costs (in this case, at least at first analysis the ratepayers), and they go to them <u>as soon as the benefits are available</u>. The "benefit" is usually, in fact, accelerated deduction of all or part of the cost.

10.2.28 In the normal situation, there is a benefit going to the ratepayers through reduced taxable income (and therefore tax) in year one, even though rates will only include the year one cost that generated that benefit in, say, year four. In the OPG case, though, the benefit has already been provided in the tax system to the Applicant. When, therefore, should the Board pass that benefit on to those who should ultimately have it, the ratepayers?

10.2.29 In some respects, the proposal of the Applicant in the Original Decision was the closest to being like the normal situation. The Applicant said that it had received some tax benefits that belong on principle to the ratepayers, and normally would have already gone to the ratepayers. The Applicant wanted them to go to the ratepayers right away, in effect to "catch up" to the pattern of benefits and costs that would have arisen in the normal situation.

10.2.30 Unfortunately, that approach, however attractive conceptually, required some very unusual assumptions about tax benefits and costs in its implementation, so was rejected by the Board in the Original Decision in favour of another approach, which had its own problems. In the Review Decision, the Board rejected that as well, instead creating a variance account and reiterating the principle that should be applied.

10.2.31 In our submission, the appropriate response, consistent with the TLVA, is to provide all of the tax benefits to the ratepayers through application of the timing differences to the taxable income calculation in each year of the post-regulation period, until the timing differences pre-regulation have all been used up.

10.2.32 By way of example (we will get to the real numbers later), if the extra tax deductions available to the Applicant pre-regulation (for costs that the ratepayers will bear post-regulation) are, say, $400 million, then there should be an adjustment to reduce the taxable income for ratemaking purposes every year, starting in 2008, until the entire timing difference has been applied. If the taxable income in the last nine months of 2008 would be, for example, $100 million, then for ratemaking purposes taxable income should be reduced to zero, and $300 million is left for 2009 and thereafter. If there would be another $120 million of taxable income in 2009, that should also be reduced to zero, and there would be $180 million left for 2010 and beyond, and so on until there is none left.

10.2.33 ***Losses vs. Deductions.*** It is very important to note that this discussion is not about tax loss carryforwards, because those are irrelevant. We are not in any case talking about tax loss carryforwards, because the Applicant doesn't have any. All extra deductions were used up in the past to shelter income from tax then. There are no losses left. [K14.3]

10.2.34 Instead, this discussion is actually about tax deductions, the actual timing differences analyzed above.

10.2.35 This is easiest understood by an example. Suppose in one of the pre-regulation years the Applicant had total accounting income of $500 million, and included in that was total income from the prescribed facilities (ignoring Bruce for the time being) of $200 million. Suppose further that the tax system allowed additional deductions, through timing differences, of $300 million. The following three conclusions would be true:

(a) There would be no actual loss, and therefore no loss carryforward in later years. From an entity point of view, there would be taxable income of $200 million ($500 million accounting income less $300 million additional deductions for timing differences). The Applicant would immediately save tax on $300 million of income. This is a real tax saving.

(b) There would be a "regulatory" tax loss of $100 million ($200 regulatory accounting income less $300 million additional deductions for timing differences). The Applicant would immediately save tax on $200 million of regulatory income, and would have a $100 million loss carryforward available to shelter income in subsequent years. This is not a real loss carryforward, though. It is a fiction created solely for regulatory purposes.

(c) The ratepayers would face an obligation in the future to pay additional tax costs on $300 million of taxable income, the full amount of the timing differences. This is a real obligation. No fiction.

10.2.36 In our submission, the relevant figure here is the amount of tax benefits available to the shareholder that will be borne by the ratepayers as increased costs later. In this simple example, that number is $300 million of deductions. That is the tax benefit that the ratepayers should get.

10.2.37 Why is the tax loss not also relevant?

10.2.38 First, there is no actual tax loss, so relevance is not based on consistency with reality.

10.2.39 Second, if one limits the discussion to the fictional "regulatory" tax loss, even there the loss obscures the real economic impact. The $300 million of timing differences is made up of:

- ***(a)*** $100 million that has been used by the shareholder to reduce regulatory taxes, and
- ***(b)*** $200 million that is a "regulatory" loss carryforward.

For that first $100 million the ratepayers can legitimately say "That is our deduction", because the cost associated with that deduction will in the end be paid by the ratepayers post-regulation. The fact that the shareholder has taken the benefit does not mean it should keep the benefit. In this example, the shareholder pre-regulation actually made a profit of $100 million on the prescribed facilities. The shareholder should pay the tax on that profit. If the ratepayers were limited to the loss carryforward, some of the benefits follow costs result would be eroded.

10.2.40 ***Costs vs. Timing Differences***. This leads to the last point of principle, the conceptual difference between real (i.e. accounting) losses and tax losses.

10.2.41 In the simplest case, a business loses money because it has expenses that exceed its revenues. This is an accounting loss, and if there are no timing differences, this is available to reduce taxes either on future profits, or on current profits from another business.

10.2.42 The tax benefit for an accounting loss pre-regulation belongs to the shareholder, because the loss arises out of a current actual expenditure. The Applicant spent the money, and will never get it back from the ratepayers in the future. The tax benefit that flows from it also cannot go to the ratepayers. Further, if a loss carryforward is generated by that loss, it cannot be applied in the future to reduce taxes payable by the ratepayers, for the same reason.

10.2.43 But that is not the case here. The Board is not faced with a utility that was losing money from the prescribed facilities. It is instead faced with a utility that was making money from the prescribed facilities, but enjoying timing differences that resulted in excess tax deductions. Those excess tax deductions match up with costs that are being borne, and will be borne, by the ratepayers post-regulation. Therefore, the benefit of those tax deductions belongs to the ratepayers.

10.2.44 ***Proposed Approach.*** In our submission, the Board is faced with the initial task of determining what extra tax deductions (timing differences) from the period before April 1, 2008 relate to costs that the ratepayers will bear. Whatever that number is should be applied to taxable income otherwise determined, from the commencement of regulation to date, and potentially beyond, to provide the ratepayers with the benefits to which they are entitled.

10.2.45 To implement this approach, we will, below, go through each of the major timing differences from April 1, 2005 to March 31, 2008, and assess whether they relate to costs the ratepayers will bear in the period April 1, 2008 and thereafter. We will then propose a total of timing differences that should be available to the ratepayers, and apply that to the calculation of the TLVA (and, separately, the tax provision in the forward Test Period, the tax implications of the Bruce Lease Variance Account, and the tax implications of the Bruce lease in the forward Test Period).

10.2.46 To do this analysis, we have summarized information provided by the Applicant in Exhibits K14.3 and L-01-120, which are essentially the T2S1 adjustments for each of the years 2005 through 2008. For each of these three tables, we have used the figures provided by the Applicant, with the following adjustments:

- ***(a)*** For the column labeled 2005, only three calendar quarters were in the relevant period. The Applicant adjusted for this by deducting 25% of the net result [K14.3, page 2, Line 34, Column 8]. Because our analysis requires more granularity, we have applied the same principle, deducting 25% from each of the numbers in lines 1 through 33. Subject to our comments below, the result is the same.

- ***(b)*** The 2008 data is taken from L-01-120, but that is for a full year, and only one calendar quarter was in the relevant period. Consistent with the Applicant's treatment of 2005 (see above), and also its allocation of Bruce lease revenues within 2008 [H1/1/1, Table 10a], we have allocated 25% of each line item to the first quarter of 2008.

- ***(c)*** In K14.3, in the line after Line 1, the Applicant has made an adjustment to remove in-period losses. Because we are reviewing the entire three year period, we have deleted that adjustment. The result is that the actual accounting income for the 36 months in question is shown in our "Totals" column.

- ***(d)*** We have added a line at the bottom, called "Net Timing Differences". As noted in our earlier discussion, this is the critical number that has to be addressed by this Board. That line, consistent with the income tax rules, is the difference between Line 26, the deductions allowed for tax purposes, and Line 15, the accounting deductions not allowed for tax purposes. As Line 26 always exceeds Line 15, this is a calculation of the net timing differences for each year, and for the entire period.

10.2.47 The first of the three summary tables, shown in Appendix A, is the calculation of taxable income and timing differences under the category that the Applicant calls "Regulated", which includes the prescribed facilities and Bruce. It is found in Column 5 of the source documents.

10.2.48 The second of the three summary tables, shown in Appendix B, is the calculation of taxable income and timing differences for Bruce. It is found in Column 6 of the source documents.

10.2.49 The third of the three summary tables, shown Appendix C, is the calculation of taxable income and timing differences under the category that the Applicant calls "Revised Regulatory". This is the total of all Regulated, less Bruce and certain other adjustments, and is found in Column 8 of the source documents.

10.2.50 ***Overall Tax Position of the Applicant.*** Before going to the detailed review of the timing differences, we believe it is important to understand the tax context of the Applicant for the period April 1, 2005 to March 31, 2008. As disclosed in Exhibit K14.3 and L-01-120, calculated as described earlier, the following facts are true:

(a) The Applicant had a total of $1,539 million of accounting income in those three years, but paid tax on only $208.6 million. Part of the reason was that the taxable income was $703.5 million, due to $835.5 million of total timing differences. In addition, the Applicant used $476.0 million of tax loss carryforwards from the period prior to 2005 to reduce taxable income further. The evidence in this proceeding does not disclose whether any of those loss carryforwards arose because of timing differences in the prescribed facilities prior to 2005. [for these numbers, see column 3 of the source documents]

(b) The Applicant's Unregulated operations (excluding Bruce) had a total of $1,053.4 million of accounting income in those three years, but had taxable income of $1,382 million. This is because the unregulated assets are older, and so OPG is now in the period where the earlier tax benefits are being repaid (area C of figure 1 in para.10.2.14 above). The $476 million of prior period tax loss carryforwards discussed above were applied to reduce taxable income to $888 million, but tax was not paid on that amount. Net tax losses in the prescribed facilities and Bruce resulted in the net taxable income of $208.6 million shown above, on which tax was actually paid. Thus, for the unregulated operations excluding Bruce a total of $1,163.4 million of taxable income escaped tax due to a combination of tax losses generated by the regulated assets in the same period, and tax loss carryforwards from a prior period that may also have been generated by the regulated assets.

(c) In this period, the Prescribed Facilities and Bruce did not lose money. As can be seen in Appendix A, the regulated assets made an accounting profit in those 36 months of $485.7 million. No tax was paid on that profit, because of timing differences. Tax deductions exceeded related accounting deductions by $1,164.1 million in that period. Thus, in addition to paying no tax on the regulated income, the Applicant had $679.3 million of regulated tax losses generated in the period, which were applied by the Applicant to reduce taxes payable on unregulated activities.

10.2.51 The result of all this is that the Applicant had $1,164.1 million of extra tax deductions available in the three years prior to April 1, 2008, and used those tax deductions to ensure that no tax was payable on $485.7 million of income from regulated assets, and $679.3 million of income from unregulated assets.

10.2.52 The question to be addressed, in our submission, is how much of that $1,164.1 million of timing differences represents tax benefits for costs that the ratepayers will bear. Whatever that number is, the benefit of those deductions should go to the ratepayers, either for the prior test period, 2008/9, the extension period 2010, the forward test period 2011/12, or beyond.

10.2.53 In the following analysis, we will review the major components of that $1,164.1 million from three perspectives: those timing differences relating to Bruce (column 6), those relating to the other prescribed facilities (column 8), and the adjustments OPG has made in addition to those components (column 7).

10.2.54 ***Nuclear Waste and Decommissioning Costs.*** It is important to note that by far the largest component of the timing differences relates to nuclear waste and decommissioning costs. For accounting purposes, the Applicant had $1,716 million of expense deductions relating to these costs [App. A, Line 3], but had tax deductions totaling $2,726.9 million [App. A, Line 18] relating to those costs. The total timing difference is $1,010.9 million over those three years. This has three components:

(a) The Applicant has allocated $153.6 million of the accounting expenses for nuclear waste and decommissioning to Bruce [App. B, Line 3], and $986.8 of the tax deductions [App. B, Line 18], for a net timing difference of $833.2 million.

(b) The Applicant has made adjustments (reductions) to the accounting expenses for nuclear waste and decommissioning of $1,495 million [K14.3, Column 7, Line 3 and L-01-120, Column 7, Line 5], and adjustments (reductions) to the tax deductions for of $1,076.9 million, for a net negative timing difference from adjustments of $418.1 million.

(c) The Applicant calculates that the amounts remaining for Revised Regulatory are accounting expenses of $67.5 million [App. C, Line 3] and tax deductions of $663.2 million [App. C, Line 18], for a net timing difference of $595.7 million.

10.2.55 With respect to all of the timing differences in Column 8 (Appendix C) relating to nuclear waste and decommissioning, it is submitted that those deductions will ultimately be borne by the ratepayers, and so should be available to the ratepayers starting April 1, 2008 to reduce taxable income on the prescribed facilities. The timing difference in this category is $595.7 million of deductions that should be used to benefit the ratepayers.

10.2.56 With respect to the timing differences in Column 6 (Appendix B) relating to nuclear waste and decommissioning, that is a little more complicated. The Applicant has two arguments as to why these timing differences should not be for the benefit of the ratepayers.

10.2.57 First, a portion of those Bruce timing differences on nuclear waste and decommissioning represents an amount that the Applicant paid in 2007 to the segregated fund, and deducted at that time for tax purposes, but will not create a tax cost for the ratepayers in the future. The reason for that is that it was paid out of funds received by the Applicant in a prior year, and on which tax was paid.

10.2.58 SEC agrees that this amount of the timing differences relates to a tax cost in a prior period, not a tax cost that ratepayers will bear. Therefore, it should be excluded from the tax deductions that should be held for the benefit of the ratepayers.

10.2.59 We have concluded that the most likely number for this is $225 million (there is some uncertainty since the evidence was led late in the day, and was not subject to more than a cursory review), and propose that the timing differences applicable to Bruce nuclear waste and decommissioning costs be reduced by that amount, from $833.2 million to $608.2 million.

10.2.60 Second, the Applicant argues [AIC, p. 62] that the remaining timing difference for Bruce in this category is not available to the ratepayers at this time, because the Board in the Original Decision determined that Bruce lease revenues and expenses should be calculated on a GAAP basis. As a result, they say [Tr.14:165], the ratepayers will get the benefit of these tax deductions when GAAP recognizes them, i.e. well into the future.

10.2.61 In our submission, this argument has more sophistry than substance.

10.2.62 At the time of the Original Decision, the Board did not have before it any evidence on the tax position of Bruce from 2005 through 2008, and in particular had no idea of the size of the overall timing differences [$799.3 million – see App. B] that had accrued over that period. In deciding that GAAP should be used to calculate the net Bruce lease revenues, the Board was deciding to simplify the calculation and recognize that Bruce is not part of the prescribed facilities [Original Decision, p. 110].

10.2.63 However, the Board was not, in our submission, intending to say that Bruce should be an exception to the "benefits follow costs" principle related to tax calculations.

10.2.64 Yet, if the Applicant's argument on this point is accepted by the Board, that is precisely the result. The tax system will allow early deduction of certain costs (nuclear waste and decommissioning), and the benefit of deducting those costs early will go, not to the ratepayers who will bear those costs, but to the shareholder who will not bear those costs. This is not consistent with the "benefits follow costs" principle.

10.2.65 In this case, if the ratepayers have the responsibility to cover the net costs of the Bruce lease, which they do (as we can see in the Bruce Lease Cost Variance Account), then any tax benefits relating to those net costs belong to the ratepayers as well. The net cost of nuclear waste and decommissioning, to the extent that it is not covered by the revenues from the lease itself, is paid by the ratepayers, so they are entitled to the related tax benefit.

10.2.66 Note that it is not enough for the Applicant to say that the ratepayers will get the tax deductions eventually. The tax benefit is precisely the ability to deduct early. If the tax deductions are withheld from the ratepayers until those deductions appear in the accounting income calculation, the ratepayers will have been completely denied the very benefits that the tax system provides.

10.2.67 It is therefore submitted that the amount of $608.2 million of tax deductions in excess of accounting deductions in 2005 through 2008 relating to Bruce nuclear waste and decommissioning expenses should be available to reduce tax expense recoverable in rates for the period 2008 and thereafter.

10.2.68 In aggregate, therefore, it is submitted that the total timing differences for nuclear waste and decommissioning expenses of $608.2 million relating to Bruce, and $595.7 million relating to the prescribed facilities, in aggregate $1,203.9 million, are tax deductions that should be allocated to the ratepayers and used to reduce taxable income and therefore the tax recoverable in rates in the period commencing April 1, 2008.

10.2.69 ***Pension and OPEB Expenses.*** Unlike nuclear waste and decommissioning costs, which created a tax benefit in the 2005 – 2008 period, the Pension/OPEB timing differences created a tax cost in that period. Deductions for accounting purposes totaled $1,014.8 million in the period [App. A, line 5], while the deductions for tax purposes totaled $772.9 million [App. A, lines 19 and 20], leaving a net increase in taxable income in that period of $241.9 million. In effect, it is a negative timing difference. None of it relates to Bruce. The figures are the same in Appendix A as Appendix C.

10.2.70 The question that the Board has to address in this context is whether that tax cost is the result of a benefit from a period prior to April 1, 2005, or whether it is a tax cost that will result in a tax benefit after March 31, 2008. In the former case, the cost relates to a benefit that the shareholder has already received, so it does not figure into the post-regulation period. In the latter, case, the ratepayers will eventually receive the benefit of this timing difference, so they should bear the cost as well.

10.2.71 There is limited evidence on this point in the record. Although the Applicant has provided an explanation, the record does not show whether this is a forward-looking or backward-looking tax cost. We invite the Applicant in Reply Argument to provide evidence references that would assist, as we have been unable to find any.

10.2.72 Logically, this net tax cost in the 2005 to 2008 period probably relates to prior periods. The Applicant has made clear that it has an aging workforce, which implies that its sequence of pension obligations and payments is maturing. As the workforce ages, the pension cost should be closer to the end of the cycle, as is the case with aging infrastructure (below). If the tax deductions are less than the accounting deductions, that implies that the tax rules in this context follow the normal pattern, which we saw in Figure 1 earlier. If that is correct, this $241.9 timing difference would be for account of the shareholder, as it relates to pre-2005 tax benefits that the shareholder has already received.

10.2.73 However, we conclude after reviewing the record that there is insufficient evidence for the Board to reach this conclusion. The pattern of spending on Pension and OPEB, and the pattern of accounting accruals, is not as regular and predictable as depreciation and CCA, and it is further complicated by the fact that, unlike other utilities, the Applicant accounts for its Pension costs on an accrual basis rather than on a cash basis for ratemaking purposes. The cash basis is similar to the tax rules, while the accrual basis produces the timing differences in the 2005 – 2008 period.

10.2.74 In our submission, the lack of evidence means that this part of the timing differences cannot be included in the Board’s calculation in this proceeding. We propose, instead, that the Board set this timing difference aside, and invite the Applicant to come back in their next rate case with evidence to show whether this timing difference relates to tax benefits prior to April 1, 2005, or subsequent to March 31, 2008. Depending on the outcome of that analysis, the Board will then be in a position to determine whether the ratepayers should be required to cover the eventual tax cost on this timing difference, and if so on what terms.

10.2.75 In the meantime, we propose that this should not have any impact on the unutilized tax deductions available to benefit the ratepayers as of April 1, 2008.

10.2.76 ***Amortization and CCA.*** The classic timing difference is capital cost allowance (CCA) and amortization. Figure 1 in para. 10.2.14 is the common way of teaching this tax expenditure pattern. When assets are newly acquired, CCA tax deductions (usually based on declining balance, and using accelerated depreciation rates) exceed the accounting amortization. As assets get older, the lines cross and the accounting amortization, which does not decrease, is more than the CCA. This is an effective fiscal and tax policy because it incents spending on long-lived capital assets, which is good for the economy both by generating economic activity, and upgrading manufacturing and other business infrastructure. In short, businesses who buy new assets are more productive, and businesses who sell those assets create jobs and growth.

10.2.77 In the case of most regulated entities, whose business is transmission or distribution, this pattern of tax benefit and tax cost is muted by the fact that they are constantly incurring new capital expenditures to renew, upgrade, or expand their system. For any individual asset, the tax benefit will arise at the beginning, and as it ages that will become a tax cost. But, on a portfolio basis, the net tax costs associated with older assets are balanced by the tax benefits from the new capital spending.

10.2.78 For a generation utility, the pattern can be more of a problem. Once the utility spends money on a generating facility, the ongoing capital spending to renew, upgrade or expand the facility is often a small amount compared to the original cost. Unless the utility is building new generation, it will ultimately find that the tax benefits of new spending are not enough to offset the tax cost of older assets.

10.2.79 That is precisely what is happening to the Applicant. As we saw earlier [para. 10.2.49(b)], The unregulated operations had $1,053.4 million of accounting income, but $1,382.0 million of taxable income, in the 36 months ending March 31, 2008. The primary reason for this was the excess of accounting amortization over CCA in those years. The unregulated assets are older, and the tax breaks available earlier are now coming home to roost.

10.2.80 The same is true of both Bruce and the prescribed facilities. In the case of Bruce, CCA in the 2005-2008 period was $120 million [App. B, Line 16], while accounting amortization was $267.1 million [App. B, Line 2], producing a negative timing difference of $147.1 million. Because this is the tail end of earlier tax benefits (i.e. none of this relates to benefits that will arise in the post-regulation period), this tax cost is for account of the shareholder.

10.2.81 In the case of the prescribed facilities, CCA in that period was $915.4 million [App. C., Line 16], while the accounting amortization in the same period was $942.6 million [App. C, Line 2]. The resulting negative timing difference of $27.2 million is also for account of the shareholder, as it also relates to prior period tax benefits (although, in this regard, see our comments on pre-2005 losses, below).

10.2.82 The result is that, while there is an overall negative timing difference for amortization and CCA, none of that relates to the ratepayers, as they will not get going forward benefits from those costs.

10.2.83 (Indeed, in future years the ratepayers will have the tax expense calculated to include this incremental tax cost, even though it relates to the tax benefits received by the shareholder prior to regulation. While this is unfair to the ratepayers, we have not been able to identify a reasonable method of adjusting for this going forward.)

10.2.84 Because these timing differences do not connect to the post-regulation period, they should be treated as zero for the purposes of calculating the net tax deductions available for the ratepayers going forward.

10.2.85 ***PARTS Deferral Account.*** This regulatory liability of the Applicant relates to spending prior to 2008 that is being amortized and charged to ratepayers. The amount that the ratepayers are being asked to pay over time is thus the portion of this prior expenditure for which the tax deductions should belong to the ratepayers.

10.2.86 There are two issues with respect to this amount.

10.2.87 First, what is the correct calculation of the amount that the ratepayers are being asked to pay? There was considerable discussion about this, and there are a number of possible results. The Applicant takes the position that the amount outstanding as of April 1, 2008 is $112.3 million, whereas the amount in the Original Decision is $183.8 million. We were unable to reach a conclusion on this, so have used the Applicant's number.

10.2.88 Second, the Applicant takes the position that the tax deductions should flow through to the ratepayers only as the deferral account is recovered from the ratepayers.

10.2.89 In our submission, this position is untenable. The Applicant is collecting interest on the deferral account to reflect the fact that they have incurred the expenditure in advance of collecting it from the ratepayers. Once they are made whole on the timing, the expenditure is in the end being incurred by the ratepayers, and the tax benefit (early deduction of the cost) should follow the cost.

10.2.90 Therefore, we believe that a net unutilized tax deduction in the amount of at least $112.3 million is available due to the PARTS Deferral Account as of April 1, 2008..

10.2.91 ***Nuclear Liability Deferral.*** The Nuclear Liability Deferral Account had a balance in it on April 1, 2008 of $163.9 million [H1/1/1, Table 1b, Line 9]. In the Original

Decision the Board ordered payment of this amount by the ratepayers over 33 months commencing April 1, 2008 [AIC, p. 87].

10.2.92 An extra tax deduction of $130.5 million related to this amount was taken by the Applicant in 2007, when the account was established. This is included in Appendix A at Line 23, for the full Regulated assets. However, as seen in K14.3 for 2007, on the same line, the Applicant has removed this amount in Column 7 as an adjustment.

10.2.93 This adjustment is not justified. This amount is in fact an amount that generated a 2007 tax deduction, and which is being recovered from the ratepayers in 2008 through 2010. Since the ratepayers are paying the cost, the tax deduction should also reduce the taxable income on which the tax provision in rates is calculated.

10.2.94 There is a further complication associated with this account. While the amount that the ratepayers are being asked to pay is $163.9 million, the prior tax deduction is only $130.5 million, and the amount ordered cleared in the EB-2007-0905 proceeding was actually only $130.5 million as well [EB-2007-0905 Payment Order, Appendix D, Table 1]. We have been unable to identify the $33.4 million difference, which does not appear to be explained in Exhibit H1/1/1 dealing with the deferral and variance account balances.

10.2.95 Faced with this discrepancy, we have limited the adjustment below to $130.5 million, which is the amount of the disclosed tax deduction taken in 2007, but we comment on the issue of the amount to be recovered from ratepayers in a later section of this Final Argument.

10.2.96 ***Summary of Timing Differences Allocable to the Ratepayers.*** The result of the above analysis is that the following net timing differences for the period April 1, 2005 to March 31, 2008 should be available as deductions in the calculation of taxable income after that date.

Category	Prescribed Facilities	Bruce	Total
Nuclear Waste and Decommissioning	595.7	608.2	1,203.9
Pension and OPEB Expenses	0.0	0.0	0.0
Segregated Fund Receipts and Spending	213.9	(0.2)	213.7
Depreciation and CCA	0.0	0.0	0.0
PARTS Deferral Account	112.3	0.0	112.3
Nuclear Liability Deferral	130.5	0.0	130.5
TOTALS	1,052.4	608.0	1,660.4

10.2.97 ***Calculation of the Balance in the TLVA – 2008/9.*** The TLVA is intended to capture the difference between the amount by which rates were reduced in the Original Decision due to:

(a) the application of tax losses not allocable to the ratepayers, reducing the provision for taxes that would otherwise have been included in rates, and

(b) the additional mitigation amount, which reduced rates by the net value of further tax losses.

10.2.98 There are more than sufficient tax deductions allocable to the ratepayers to result in there being no taxable income in the period 2008/9, the former test period. The amount of the taxable income otherwise expected for that period is $212.9 million. Application of an equivalent amount of the timing differences summarized above brings this taxable income to zero, and leaves $1,447.5 million of additional (unutilized) tax deductions from timing differences still available to the ratepayers.

10.2.99 On the other hand, the mitigation amount of $168.7 million [K14.2, p. 65] is simply a reduction of revenue requirement. That balance should still remain in the TLVA, and pursuant to the Review Decision should be cleared as a charge to ratepayers. We comment further on the tax implications of this clearance, below.

10.2.100 ***Calculation of the Balance in the TLVA – 2010.*** Conceptually the issue would be the same for 2010 as for 2008 and 2009, if the original TLVA had been set up for three years rather than two, or if in the Extension Decision the Applicant had sought guidance on how they should deal with it for their additional year, 2010.

10.2.101 In preparing this Final Argument, SEC has had an opportunity to review in draft the submissions on the 2010 TLVA entries as developed by VECC. We agree with their rationale for urging that the Board not allow the 2010 entries in this account.

10.2.102 Notwithstanding our agreement with VECC on these points, on our view of the situation the final result is that, while all 2010 entries (tax impacts plus mitigation amount) in the account should be removed, the timing differences available to the ratepayers still have to be used to reduce the 2010 tax obligation.

10.2.103 Our reasoning is this. The tax deductions available to the ratepayers arising out of the timing differences are in essence a fund of tax benefits that should be applied, as per the tax laws, as each year's taxable income arises. Each year there is taxable income before these are applied, and then some of the extra tax deductions are used up. A balance is then remaining for the next year.

10.2.104 Taking that same concept and applying it in the regulatory context, rates for 2008 and 2009 would otherwise have resulted in taxable income of $212.9 million, but by applying the ratepayers' available tax deductions from timing differences, that is reduced to zero, and the balance of unutilized tax deduction is reduced to $1,447.5 million. The 2010 rates also resulted in taxable income of $121.7 million [$212.9

million x 12/21], but the ratepayers did not have any tax included in rates. The taxable income thus uses up a further $121.7 million of the unutilized tax deductions, leaving $1,325.8 million remaining at the end of 2010. This is not because there is an entry in the TLVA (there would not be because there was no Board decision applying the TLVA to 2010), but rather because the taxable income otherwise determined in fact for 2010 is still reduced to zero, and that uses some of the tax deductions.

10.2.105 ***Tax Provision for 2011 and 2012.*** The Applicant forecasts taxable income from the prescribed facilities in 2011 and 2012 of $658.9 million. The unutilized tax deductions remaining at the end of 2010 total $1,325.8 million, meaning that all of the 2011 taxable income and all of the 2012 taxable income are sheltered by those timing differences.

10.2.106 In addition, we have proposed above that the 2008/9 mitigation amount of $168.7 million be recoverable from ratepayers. As this was not included in taxable income in those years, it would be taxable as recovered. Since there are additional tax deductions available, those should be used to reduce the taxable income represented by this recovery to zero.

10.2.107 As noted earlier in these submissions, the result of this adjustment for the Test Period would be that the revenue requirement for each of 2011 and 2012 is reduced by the grossed up tax provision, i.e. $262. 6 million in aggregate.

10.2.108 In our submission, at the end of 2012, and assuming that the TLVA recoveries have been sheltered in full by deductions, a total amount of deductions remain available for the ratepayers in 2013 and beyond of $498.2. This is subject to recalculation as a result of many factors from this Board’s decision in this matter.

10.2.109 ***Tax Losses Prior to April 1, 2005.*** As we have noted earlier in these submissions, the Applicant reduced its taxable income in the period April 1, 2005 to March 31, 2008 through the application of $476.0 million of tax losses from the period prior to 2005. The evidence does not reveal whether these tax losses relate to the prescribed facilities, Bruce, or the unregulated assets.

10.2.110. In our submission, there is no logical reason why the ratepayers, who may incur costs in the future associated with any timing differences embedded in those losses, should not have the benefit of those timing differences in the same manner as they would timing differences arising in 2005-2008. At the very least, if the $476.0 million of losses applied to reduce taxes on the unregulated assets in 2005 and 2006 were created through timing differences relating to the prescribed facilities, those net timing differences should be available to the ratepayers going forward. The tax costs in the future arising out of those timing differences will be borne by the ratepayers, so the tax benefits should be theirs as well.

10.2.111 The record does not give the Board sufficient information to determine whether these $476.0 million of losses, or some greater or lesser amount, should be for the account of the ratepayers when future taxes are calculated. Therefore, subject to one comment below, it is submitted that the Applicant should be directed to do a detailed review of the creation of those losses in light of the principles enunciated in these submissions, and file that review in their next rate case.

10.2.112 We note that the losses of $476.0 may have a number of adjustments, because as we have seen above the application of the benefits follow costs principle can sometimes be a bit complicated. One such adjustment relates to the negative timing differences arising out of amortization and CCA for Bruce ($147.1 million) and for the prescribed facilities ($27.2 million). Those negative timing differences relate to the period prior to 2005. To the extent that the pre-2005 losses were created by amortization/CCA timing differences, they should be offset against the tax costs being borne by the shareholder for these same items in the 2005-2008 period.

10.2.113 ***Conclusion.*** In summary, it is submitted that the Board should make the following orders with respect to the Tax Loss Variance Account and other tax-related issues in this proceeding:

(a) The "mitigation amount" of $168.7 million for the period 2008/9 should be recovered from the ratepayers over 2011-2014 in the manner proposed by the Applicant.

(b) The Applicant's proposal to deem a "mitigation amount" for 2010 should be denied.

(c) The Board should establish the amount of unutilized tax deductions available on April 1, 2008 to offset future taxable income for the prescribed facilities to be $1,660.4 million.

(d) The amount of $212.9 million of the unutilized tax deductions as of April 1, 2008 should be applied to reduce forecast taxable income for the previous test period to zero, leaving a balance of $1,447.5 million of unutilized tax deductions available for the ratepayers as of December 31, 2009.

(e) The amount of $121.7 million of the unutilized tax deductions as of December 31, 2009 should be applied to reduce the expected taxable income for 2010 to zero, leaving a balance of $1,325.8 million of unutilized tax deductions available for the ratepayers as of December 31, 2010.

(f) An amount of the unutilized tax deductions as of December 31, 2010 equal to the net taxable income of the Applicant for 2011 as otherwise calculated in the final rate order should be applied to reduce that taxable income for 2011 to zero, thus reducing the payment amounts for 2011 by the amount of any grossed up tax provision that would otherwise be required.

(g) An amount of the unutilized tax deductions as of December 31, 2011 equal to the net taxable income of the Applicant for 2012 as otherwise calculated in the final rate order should be applied to reduce that taxable income for 2012 to zero, thus reducing the payment amounts for 2012 by the amount of any grossed up tax provision that would otherwise be required.

(h) $168.7 million of the unutilized tax deduction be applied to reduce to zero the taxable income otherwise generated by recovery of the 2008/9 mitigation amount.

(i) Subject to the reports proposed below, the remaining balance of unutilized tax deductions, forecast to be approximately $450-$500 million, be declared available to reduce taxable income for ratemaking purposes in the period after 2012.

(j) With respect to timing differences for Pension and OPEB costs, the Applicant be directed to file a detailed report in its next cost of service case providing sufficient information for the Board to determine whether Pension/OPEB timing differences in 2005-2008 relate to the period prior to that time, or the post-regulation period.

(k) With respect to the pre-2005 tax losses utilized by the Applicant to reduce unregulated taxable income in 2005 and 2006, the Applicant be directed to file a detailed report in its next cost of service case providing full details on how these losses arose, and the extent, if any, that they relate to tax costs incurred or expected to be incurred and included in rates in the period after March 31, 2008.

Bruce Lease Revenues Variance Account

10.2.114 The Bruce Lease component of the Applicant's business is unique. On the one hand, it owns the asset – the Bruce NGS – and bears all the costs of ownership of the asset. On the other hand, the lessee Bruce Power bears all the operating costs, and pays a lease payment for the use of the asset. While the asset is not one of the prescribed facilities, and so is not regulated in the normal sense, the net difference between the lease payments, and the costs associated with the asset (depreciation, nuclear waste and decommissioning, certain market price risks, etc.), is either a recovery from or credit to the ratepayers in the calculation of the payment amounts.

10.2.115 In the Original Decision, the Board interpreted the government's requirement to adjust for this net difference to mean that actual net revenues had to be adjusted, requiring the creation of the Bruce Lease Revenues Variance Account. The Board also determined that the costs to be included in the calculation do not include a rate of return. In their view, the intent was that the Applicant would make what it made on the arrangement, and once it paid its taxes on whatever it made, the rest would go to the ratepayers.

10.2.116 It is submitted that the original intention of this arrangement, including the involvement of the ratepayers, was to ensure that the net profits associated with Bruce should go back to the ratepayers. It was never intended to be a subsidy by ratepayers of the Bruce lease arrangement.

10.2.117 What has transpired instead is that the "net difference" in the Bruce Lease Revenues Variance Account as of 2010 is $296.6 million recoverable from the ratepayers. The reason for this is that the Original Decision included credits to customers that ultimately gave ratepayers $278.2 million over the period April 1, 2008 through December 31, 2010 [H1/1/2, Table 4, updated October 8, 2010]. However, the actual net revenues during that period totaled a net loss of $27.5 million [H1/1/1, Table 10a and previous cite].

10.2.118 The main reason that the actual net revenues are so low appears to be that the segregated funds lost money in 2008, resulting in a negative revenue amount of $179.9 million in the period April 1, 2008 to December 31, 2008 [H1/1/1, Table 10a].

10.2.119 There is also a substantial impact arising because the lease payments in 2009 were significantly lower than a normal year. This is in part because, pursuant to the lease, the Applicant is at risk if HOEP drops below $30/MWh. In 2009, it did so, and as a result supplementary rent was reduced by $69 million [G2/2/1, p. 7]. There were also two adjustments due to accounting decisions. The value of the supplementary rent (but not the actual supplementary rent) was reduced by $118 million to reflect future risk that HOEP would drop below $30/MWh [ibid.], and the value of the base rent (but not the actual base rent) was reduced by $41 million to reflect the change from cash accounting for Bruce to CGAAP, and the effective extension of the Bruce lease to 2036 [ibid.].

10.2.120 In our view, the loss on the seg funds in 2008, which has been in part made up in 2009 and 2010, is a one-time event that is not likely to recur in the near term. Further, the two accounting adjustments totaling $159 million in 2009 were one-time events, and not part of the normal level of variances for which the Bruce Lease Cost Variance Account was intended. Asking the ratepayers to pay almost $300 million in recoveries over the next two years due to these one-time unusual events is not, it is submitted, appropriate. This would be inconsistent with the original intention of the variance account.

10.2.121 We therefore propose that the current balance in the Bruce Lease Net Revenues

Account should be recovered from ratepayers, not over the Test Period as proposed by the Applicant, but over the period ending December 31, 2014, a total of 46 months.

Nuclear Liability Deferral Account

10.2.122 This account records the different in nuclear liabilities that arises when a new approved ONFA Plan is approved. Pursuant to the Original Decision, the balance in this account was $130.5 million [EB-2007-0905 Payment Order, App. D, Table 1]. No changes to the ONFA Plan have taken place since 2007.

10.2.123 Notwithstanding the above, the Applicant shows the opening balance of this account on April 1, 2008 to be $163.9 million, and includes an addition ("transaction") of $31.3 million in the first quarter of 2008 [H1/1/1, Table 1a]. The evidence does not appear to provide any description of this addition [see H1/1/1, pp. 10-11]. We have not seen an explanation in any other part of the evidence, and we are unable to reconcile this entry with the fact that the ONFA Plan did not change in 2008.

10.2.124 We invite the Applicant in their Reply Argument to show where the evidence satisfactorily explains this amount. In the event that it does not, it is submitted that the amount to be cleared from this account should be reduced. However, the Applicant should have the right in a future proceeding to bring forward evidence supporting this entry, and have it recovered at that time.

Other Accounts

No submissions.

10.3 ***Disposition Methodology***

10.3.1 No additional submissions. Where we have comments on disposition, they are included in the discussions of the particular accounts.

10.4 ***Continuation of Existing Deferral and Variance Accounts***

No submissions.

10.5 ***Proposed IESO Non-Energy Charges Account***

10.5.1 The Applicant is seeking a new account to record variances from forecast of IESO non-energy charges. These charges are dominated by the Global Adjustment [AIC p. 95], but also include rural rate assistance, transmission charges, and debt retirement charges. For most ratepayers, including the Applicant, they make up a sizeable portion of the electricity bill.

10.5.2 When we first saw that this account was being requested, our immediate reaction was "can we have one too?" The Applicant is absolutely right. These charges are material, and can cause dramatic increases or decreases in the delivered cost of electricity in Ontario. In this respect the Applicant, as an electricity consumer, is in exactly the same boat as every other ratepayer.

10.5.3 Conceptually, variance accounts are appropriate in situations in which a cost is unpredictable, it is not within the control of utility management, and it is appropriate that the risk of variations in that cost be shifted from the utility to the ratepayers. For most costs, such a shift is not appropriate. Things like the weather, or economic conditions, equipment prices, or even wage settlements, all have a greater or lesser degree of unpredictability, and all are to only some extent within the control of management. Most utility costs, regardless of the extent to which they are exogenous, are considered to be part of the normal business risks of the enterprise, for which the utility is compensated in its cost of capital.

10.5.4 In our view, the fact that the Applicant's electricity bill may be somewhat unpredictable is a normal business risk, faced by every one of its ratepayers as well. Is it to some extent outside the control of management? Probably, although of course most ratepayers are exercising some control over this cost by conservation initiatives. But even if that is the case, it is a normal risk, and this category of risk is, in our view, part of the risks for which a cost of capital is allowed.

10.5.5 In fact, if the Board were to approve this account, it would appear to us that this would be an expansion of the ambit of deferral and variance accounts generally, and therefore likely to encourage other utilities to seek broader and broader protection against normal business risks.

10.5.6 We note, in passing, that if anything the Applicant should have less right to have a variance account like this than almost any ratepayer in the province. As we saw in Exhibit K10.3, page 17, more than 25% of the Global Adjustment in the twelve months ended August, 2010 was represented by the more than a billion dollars paid by OPA to the Applicant as a subsidy for its prescribed facilities. Thus, on the largest component of the IESO non-energy charges, the Applicant is better placed to exercise control over this cost than anyone else in the province.

10.5.7 It is therefore submitted that this account should not be approved.

10.6 ***New Accounts***

10.6.1 ***Pension/OPEB Variance Account.*** The Applicant has advised the Board [N/1/1] that it now anticipates that pension and OPEB costs for the Test Period will be $264.2 million higher than the amounts included in the Application. While this information was provided on September 30, 2010, the Applicant is not proposing to include this additional Test Period cost in the revenue requirement. Instead, the proposal is to defer payment of this amount through a "variance" account, which would be cleared in 2013 or beyond.

10.6.2 We have had an opportunity to review the submissions of Board Staff on this issue [Staff Argument, pp. 96-99], and in general SEC supports the thrust of their analysis. However, on one point we have reached a different conclusion.

10.6.3 Staff has proposed that the pension and OPEB variance account not be approved, but that the Applicant be allowed to include in rates only the cash costs of pension and OPEBs, i.e. contributions to the pension plan, and cash payments to former employees for OPEBs. Staff notes that these payments are much more stable than the accounting provisions that the Applicant is currently claiming in rates. In addition, we note that implementing this recommendation would result in the Applicant's pension and OPEB treatment being the same as most of the other utilities regulated by this Board.

10.6.4 We agree with Staff's analysis, and would add that the apparent volatility of pension and OPEB costs as seen in the Staff submission [Staff Argument, p. 98, table] is directly associated with the fact that accounting provisions are being used rather than cash costs. As interest rates and inflation change year to year, the future obligations associated with pensions and OPEBs can be altered materially, even though year after year the actual spending is roughly the same. While we can understand why the accounting rules require the recognition of these changes in the future obligation, it is not obvious to us why they need to be reflected in rates.

10.6.5 The one area in which we disagree with Staff is their alternative suggestion, on page 99 of their Argument, that if the Board does not move to a cash basis, and instead orders that the accounting cost of pensions and OPEB be included in rates, those amounts should be set aside in a segregated fund. While the accounting provision is now expected to be $318.7 million higher than the cash expenditures [Staff Final Argument, p. 98, table], we are concerned that ordering that cash to be set aside will form a precedent for other situations in which accounting provisions are not equal to cash costs.

10.6.6 Rather than force the accounting cost to equal the cash cost by increasing the cash payment, in our submission by far the better approach is to order that the cash cost only be recovered in rates. This is Staff's preferred position, of course, and we do not agree that the alternative proposed accomplishes the same result.

11 REPORTING AND RECORD KEEPING REQUIREMENTS

11.1 *General*

11.1.1 ***Additional Documents to be Filed.*** In L-1-149 Board Staff explored whether the Applicant could file additional information with the Board on an annual basis. For many of those documents, the Applicant can provide the information, and we agree with Staff [Staff Argument, p. 102-3] that filing these documents would be of assistance to the Board. Staff has provided a list, and we believe that the Board should order annual filing of those documents as proposed by Staff**.**

11.1.2 ***Audited Financial Statements.*** The Applicant, while arguing that this proceeding is not the time to deal with annual filing requirements [AIC p. 99], nevertheless has again expressed their concerns about filing audited financial statements for the prescribed facilities. They make two claims: the statements are difficult to produce, and they have limited value for the Board and the parties.

11.1.3 On the first point, we believe that the Applicant should be required to establish the appropriate systems to allow timely and efficient reporting of this information. The prescribed facilities are the biggest part of their business by far, and they get substantial benefits (and additional revenues) from being regulated. Part of the deal is that they have to provide reliable, independent information related to that regulated business. This is true for a distribution utility with 1,000 customers, for whom the cost of an audit is painful, and it should equally be true for the province's dominant generator, with billions of dollars of annual revenues.

11.1.4 We also note that now is precisely the time when this should be done. The Applicant, like most Ontario utilities, is in the process of changing systems to comply with IFRS. During the course of those changes, the opportunity should be taken to ensure that the IFRS changes also allow for the segmented auditable reporting required by its regulator.

11.1.5 On the second point, we believe that the Applicant actually has it backward. Mr. Barrett said, in cross-examination by Mr. Millar [Tr.15:91]:

> *"I would also observe that as far as I can recollect, there has been no reference in this entire proceeding to those prescribed financial statements. So, again, that reinforces our own view that they did not provide much utility to this process."*

11.1.6 With respect, this is not the right conclusion. Evidence is not shown to be valuable because it is the subject of extensive interrogatories or cross-examination. The opposite is true. Where intervenors and the Board spend a lot of time and effort trying to understand a document, that is usually because it is less valuable than it could or should have been. Where a document is not the subject of cross-examination, often the reason is that its meaning is clear. In the best of all possible worlds, the Applicant would file an Application that required no interrogatories or cross-examination. That would not mean all documents were useless.

11.1.7 Like many intervenors, SEC has a set of the evidence in this proceeding that has been extensively marked up with notes and analysis. That is the indicator that evidence is valuable. We believe that the audited financial statements for the prescribed facilities are an important part of the evidence, and assisted all parties in understanding the Applicant's business, and the case it was putting forward.

12 METHODOLOGIES FOR SETTING PAYMENT AMOUNTS

12.1 *Timing of Alternative Ratesetting Mechanism*

12.1.1 The Applicant is just completing its second application for payment amounts, and has only been regulated by this Board since 2008. The current Application is notable by the complexity and dollar impact of the issues, and their newness to this Board and to the parties. It is also striking for the extent to which the Applicant seeks – or is granted by legislation – protection from cost variances in significant aspects of its operations.

12.1.2 In the area of the capital and operating expenditures of the Applicant, this proceeding demonstrates two clear facts.

12.1.3 First, the Applicant is going through a change of corporate culture, as it struggles to adopt a more business-like approach to business planning and budgeting. It is hard not to admire the efforts the Applicant has made in a short time to move in this direction, but it is indisputable that it is still early days in that respect,

12.1.4 Second, there are major changes in the nature and size of the Applicant's costs and rate base coming over the next few years. Large assets will be taken out of service in the near term (i.e. Pickering), and new regulated assets will be added (Darlington and potentially Bruce). The fundamental economics of the Applicant's regulated business are going to change, one way or the other, and that is known today.

12.1.5 All of these facts suggest that the Applicant is not ready for any form of incentive regulation, and most approaches to IRM would not suit the Applicant in its current state. IRM is mainly for stable businesses that have relatively predictable needs over a multi-year period. The Applicant couldn't be further from that paradigm.

12.1.6 This is not to say that there are not alternative approaches to rate setting that could be considered for the Applicant over the next several years, but it is submitted that the earliest a formulaic or results-based approach is likely to be suitable is 2014 or 2015.

12.1.7 As we note below, that doesn't mean a process can't be put in place soon to develop an alternative rate setting mechanism. What it does mean, though, is that implementation of such a mechanism should not be rushed, and caution is very much required.

12.2 *Process for Establishing New Mechanism*

12.2.1 The Applicant has proposed [L-1-150] that it will file an application in 2011 for consideration of an incentive rate setting mechanism for OPG, with the intention that the Board would issue a decision or report before the end of 2011, and the Applicant's

2013 and beyond payment amounts could be based on that decision. This plan is characterized by the Applicant as "aggressive".

12.2.2 In our view, even if the Applicant is ready for incentive regulation (see above), and as much as the Applicant and others may wish to see a "short, focused hearing" for this, in fact the proposed process is overly aggressive.

12.2.3 Consideration of the IRM approach to be used for the Applicant will involve up to $4 billion of annual charges to ratepayers, over an unknown period, perhaps three or four years. Getting the right mechanism will require considerable thought/analysis, including expert review by the Board and perhaps intervenors.

12.2.4 In this context, it should be noted that the extensive work done by this Board for gas and electricity distributors may well not be applicable – or not fully - to generation rates. A host of special issues arise, including the possibility of long term contract rates for given generation sources (like OPA FIT contracts or NUG contracts), the possibility of partial IRM either for specific assets, or for specific categories of generation, the impact of changes in the electricity market prices, issues of baseload vs. non-baseload supply (the "take or pay" question) and many others.

12.2.5 Therefore, despite our view above that the Applicant is not ready for IRM, we believe it is appropriate for the process of establishing an IRM framework to start. We also agree with the Applicant that the first step is likely a proposal by the Applicant, which we would expect could be filed in the fall of next year. On that schedule, the process is likely to be completed by the end of 2012 or early in 2013. In keeping with our comments above, this would allow the Applicant to be under cost of service for 2013, and any IRM mechanisms could commence in 2014 or beyond.

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.

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Jay Shepherd
Counsel for the School Energy Coalition

Tax Calculation - Column 5 (All Regulated)

#	Particulars	2005	2006	2007	2008	Totals
	Determination of Taxable Income					
1	Earnings before tax	209.2	229.7	101.8	(55.0)	485.7
	[deleted]					
		209.2	229.7	101.8	(55.0)	485.7
	Additions for Tax Purposes					
2	Depreciation	315.8	404.5	440.0	104.3	1,264.6
3	Nuclear Waste Management Expenses	375.5	528.6	650.3	161.6	1,716.0
4	Receipts from Nuclear Segregated Funds	17.0	18.8	119.2	20.4	175.3
5	Pension and OPEB/SPP Accrual	175.4	374.4	383.7	81.3	1,014.8
6	One-time adjustment P2P3 Inventory Writeoffs					
7	One-time adjustment P2P3 CIP Writeoffs					
8	Regulatory Asset Amortization - PARTS Deferral Costs		25.1	95.5	16.6	137.2
	Regulatory Asset Amortization - Nuclear Development					
9	Deferral & Capacity Refurbishment				0.8	0.8
10	Regulatory Asset Amortization - Nuclear Liability Deferral				8.9	8.9
11	First Nations Past Grievances Provision			27.1		27.1
12	Adjustment Related to Duplicate Interest Deduction (Q1 2008)					
	Adjustment Related to Financing Cost for Nuclear Liabilities					
13	Lennox Impairment					
14	Other	39.3	35.5	31.9	31.0	137.7
15	Total Additions	922.9	1,386.9	1,747.7	425.0	4,482.4
	Deductions for Tax Purposes					
16	CCA	260.6	353.9	363.3	77.0	1,054.8
17	Cash Expenditures for Nuclear Waste & Decommissioning	63.1	153.4	169.9	48.8	435.1
18	Contributions to Nuclear Segregated Funds and Earnings	626.3	824.5	1,269.2	7.0	2,726.9
19	Pension Plan Contributions	148.5	207.0	211.0	49.8	616.3
20	OPEB/SPP Payments	28.4	54.4	57.8	16.0	156.6
21	Regulatory Asset Deduction - PARTS Deferred Costs	190.5	12.6	30.6	1.6	235.3
	Regulatory Asset Amortization - Nuclear Development					
22	Deferral & Capacity Refurbishment Variance					
23	Regulatory Asset Amortization - Nuclear Liability Deferral			130.5		130.5
	Reversal of Bruce Regulatory Asset				88.7	88.7
	SRED Qualifying Capital Expenditures				4.2	4.2
	SRED Investment Tax Credits Recognized in Reg. Earnings before Tax				7.1	7.1
24	Construction in Progress Interest Capitalized	22.2	14.9	25.8	7.8	70.7
25	Other	15.1	20.3	63.9	21.2	120.5
26	Total Deductions	1,354.6	1,641.0	2,322.0	329.0	5,646.5
27	Net Income/(Loss) for tax purposes	(222.5)	(24.4)	(472.5)	41.1	(678.4)
	Deduct:					
	Charitable Donations				0.9	0.9
28	Taxable Income	(222.5)	(24.4)	(472.5)	40.2	(679.3)
	Net Timing Differences	**431.7**	**254.1**	**574.3**	**(96.0)**	**1,164.1**

Tax Calculation - Column 6 (Bruce on a Regulated Basis)

#	Particulars	2005	2006	2007	2008	Totals
	Determination of Taxable Income					
1	Earnings before tax	81.8	115.8	147.1	(70.8)	273.9
	[deleted]					
		81.8	115.8	147.1	(70.8)	273.9
	Additions for Tax Purposes					
2	Depreciation	74.9	100.4	76.6	15.3	267.1
3	Nuclear Waste Management Expenses	10.5	16.1	53.8	73.2	153.6
4	Receipts from Nuclear Segregated Funds	8.3	9.0	24.0	4.8	46.0
5	Pension and OPEB/SPP Accrual					
6	One-time adjustment P2P3 Inventory Writeoffs					
7	One-time adjustment P2P3 CIP Writeoffs					
8	Regulatory Asset Amortization - PARTS Deferral Costs					
	Regulatory Asset Amortization - Nuclear Development					
9	Deferral & Capacity Refurbishment					
10	Regulatory Asset Amortization - Nuclear Liability Deferral					
11	First Nations Past Grievances Provision					
12	Adjustment Related to Duplicate Interest Deduction (Q1 2008)	10.1	10.5	8.7		29.3
	Adjustment Related to Financing Cost for Nuclear Liabilities					
13	Lennox Impairment					
14	Other	1.5	2.0	2.0	0.5	6.0
15	Total Additions	105.2	138.0	165.1	93.7	501.9
	Deductions for Tax Purposes					
16	CCA	34.8	43.2	39.7	2.3	120.0
17	Cash Expenditures for Nuclear Waste & Decommissioning	23.3	45.0	67.0	18.1	153.4
18	Contributions to Nuclear Segregated Funds and Earnings	159.0	212.0	563.0	52.8	986.8
19	Pension Plan Contributions					
	OPEB/SPP Payments					
1	Regulatory Asset Deduction - PARTS Deferred Costs					
	Regulatory Asset Amortization - Nuclear Development					
2	Deferral & Capacity Refurbishment Variance					
3	Regulatory Asset Amortization - Nuclear Liability Deferral					
	Reversal of Bruce Regulatory Asset					
	SRED Qualifying Capital Expenditures					
	SRED Investment Tax Credits Recognized in Reg. Earnings before Tax					
4	Construction in Progress Interest Capitalized					
5	Other	10.3	13.7	13.7	3.4	41.1
6	Total Deductions	227.3	313.9	683.4	76.6	1,301.2
7	Net Income/(Loss) for tax purposes	(40.4)	(60.1)	(371.2)	(53.7)	(525.4)
	Deduct:					
	Charitable Donations					
8	Taxable Income	(40.4)	(60.1)	(371.2)	(53.7)	(525.4)
	Net Timing Differences	**122.2**	**175.9**	**518.3**	**(17.1)**	**799.3**

Tax Calculation - Column 8 (Revised Regulatory)

#	Particulars	2005	2006	2007	2008	Totals
	Determination of Taxable Income					
1	Earnings before tax	(2.3)	78.0	(231.1)	5.2	(150.2)
	[deleted]					
		(2.3)	78.0	(231.1)	5.2	(150.2)
	Additions for Tax Purposes					
2	Depreciation	240.9	303.6	310.4	87.7	942.6
3	Nuclear Waste Management Expenses	15.0	21.9	25.2	5.4	67.5
4	Receipts from Nuclear Segregated Funds	9.0	10.0	95.0	15.6	129.6
5	Pension and OPEB/SPP Accrual	175.5	374.0	384.0	81.2	1,014.7
6	One-time adjustment P2P3 Inventory Writeoffs	36.8				36.8
7	One-time adjustment P2P3 CIP Writeoffs	28.5				28.5
8	Regulatory Asset Amortization - PARTS Deferral Costs	3.0	25.0	95.0		123.0
9	Regulatory Asset Amortization - Nuclear Development Deferral & Capacity Refurbishment					
10	Regulatory Asset Amortization - Nuclear Liability Deferral				8.9	8.9
11	First Nations Past Grievances Provision			27.0		27.0
12	Adjustment Related to Duplicate Interest Deduction (Q1 2008)	23.7	27.5	25.3	2.5	79.0
	Adjustment Related to Financing Cost for Nuclear Liabilities				13.5	13.5
13	Lennox Impairment					
14	Other	34.5	18.0	26.0	10.4	88.9
15	Total Additions	566.9	780.0	987.9	225.2	2,559.9
	Deductions for Tax Purposes					
16	CCA	228.4	306.4	305.9	74.7	915.4
17	Cash Expenditures for Nuclear Waste & Decommissioning	39.8	108.0	103.0	30.7	281.4
18	Contributions to Nuclear Segregated Funds and Earnings	181.5	242.0	225.0	14.7	663.2
19	Pension Plan Contributions	148.4	207.0	211.0	49.7	616.1
20	OPEB/SPP Payments	28.5	55.0	57.0	15.9	156.4
21	Regulatory Asset Deduction - PARTS Deferred Costs	3.0	25.0	95.0		123.0
22	Regulatory Asset Amortization - Nuclear Development Deferral & Capacity Refurbishment Variance					
23	Regulatory Asset Amortization - Nuclear Liability Deferral				0.5	0.5
	Reversal of Bruce Regulatory Asset					
	SRED Qualifying Capital Expenditures				4.2	4.2
	SRED Investment Tax Credits Recognized in Reg. Earnings before Tax				7.1	7.1
24	Construction in Progress Interest Capitalized					
25	Other	2.9	(0.7)	29.3	2.9	34.4
26	Total Deductions	632.4	942.7	1,026.2	200.3	2,801.6
27	Net Income/(Loss) for tax purposes	(67.9)	(84.7)	(269.4)	30.1	(391.9)
	Deduct:					
	Charitable Donations				0.9	0.9
28	Taxable Income	(67.9)	(84.7)	(269.4)	29.2	(392.8)
	Net Timing Differences	**65.6**	**162.7**	**38.3**	**(24.9)**	**241.7**