EB-2010-0132

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 Hydro One Brampton Networks Inc. pursuant to the *Ontario Energy Board Act* for an Order or Orders approving just and reasonable rates for the distribution of electricity commencing January 1, 2011

FINAL ARGUMENT
ON BEHALF OF THE
SCHOOL ENERGY COALITION

January 18 , 2011

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0 GENERAL COMMENTS

0.1 *Introduction*

0.1.1 On June 30, 2010 Hydro One Brampton Networks Inc. filed an Application for new distribution rates, effective January 1, 2011. The process included extensive interrogatories, a technical conference, an unsuccessful ADR, and a short oral hearing.

0.1.2 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 have also benefited from the early filing of the Final Argument of Board Staff, and in certain parts of this argument we have simply agreed with their analysis, rather than repeat it.

0.1.5 As there is no Board-approved Issues List for this proceeding, we have organized our submissions under the general headings normal and usual for a distribution rate case, consistent with the filing guidelines and the Application itself.

0.2 *Summary of Submissions*

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

0.2.2 ***The Real Deficiency.*** While the result of this Application is a sufficiency of $315,748, SEC believes that when looking at the Application from a high level, the Board should view this as presenting an effective deficiency of about $17.1 million.

0.2.3 It appears to be common ground that the Applicant's revenues have increased, since 2006 Board-approved, by about $6.0 million, or 10.7%. On the other side, the Applicant's controllable costs on an annual basis have increased by about $23.1 million, or 41.5%, over the same period. This unusual situation – costs increasing at four times the rate of customer growth - has not, in our submission, been appropriately explained.

0.2.4 The reason why this situation still results in a sufficiency is not control of costs.

Rather, it appears to be the result of the Applicant's windfall saving of about $8.5 million (the Applicant says $6.8 million) through lower taxes, and an accounting change that reduces amortization by a net of about $9.0 million. It is these two changes (tax reductions that otherwise would benefit the ratepayers on rebasing, and an accounting change that defer taxes so that the ratepayers pay them in later years) that change a $17.1 million (27.4%) deficiency into a $0.3 million sufficiency.

0.2.5 ***Load and Revenue Forecasts.*** We propose that the CDM adjustment in the load forecast should be reduced from 64.0 GWh. to no more than 18.954 GWh.

0.2.6 We also note that there appear to be two adjustments required for Other Revenues, one relating to Miscellaneous Revenues, and one relating to rent from the former daycare space.

0.2.7 ***OM&A.*** The Application proposes an increase of 61.3% from the OM&A baked into rates to the OM&A for the Test Year. In our submission, this is far in excess of a reasonable amount, looked at from any perspective.

0.2.8 SEC approaches the OM&A analysis from both a top down and a bottom up basis. The top-down approach produces a Test Year OM&A budget of $18.7 million. The bottom-up approach, which focuses mainly on FTEs and therefore personnel costs, produces a Test Year OM&A budget of $19.7 million. These are still significant increases, but less than the massive increase in the Application. We recommend the higher of the two, $19.7 million.

0.2.9 To these base budgets, we propose to add $375,000, so that over four years the incremental OMERs costs of $1.5 million can be recovered by the Applicant.

0.2.10 ***Rate Base.*** Except for the adjustment to working capital, proposed and discussed by Energy Probe, with which we agree, we have no submissions on the normal capital expenditures or rate base.

0.2.11 With respect to the GEA spending, subject to some clarifications and specific concerns, we agree in principle with the rate adder and deferral account approach.

0.2.12 ***Long Term Debt.*** Unlike other parties, SEC does not believe that the 6.95% interest rate being paid to the regulated parent company, Hydro One Networks, is appropriate to be recovered from ratepayers. In our view, the appropriate cost of long term debt of the Applicant, the same as any of the other regulated operations of Hydro One, should be the weighted average cost of long term debt of Hydro One. That rate has recently been determined [in EB-2010-0002] to be 5.67% for 2011, and in our view that is the true cost of debt of the Applicant as well.

0.2.13 If a higher rate is chosen, the effect is to allow Hydro One Networks, a regulated utility, to make an additional profit of $1.8 million by lending to a subsidiary at a higher rate than its own cost of funds. This is not appropriate.

0.2.14 ***Account 1562.*** SEC believes that it is premature for this Board panel to make a determination on clearance of Account 1562 for the Applicant. The EB-2008-0381 proceeding is still ongoing, with a conclusion expected in the next few months. Until then, we believe it is inappropriate for individual Board panels to deal with the issue without the benefit of the guidance of the Board panel hearing the generic proceeding. In effect, it is unnecessary and inefficient to reinvent the wheel.

0.2.15 If the Board does decide to determine this question now, it is our view that the rules are quite clear. The interest clawback is a rule that existed then and, fair or unfair, the Board has already ruled that it cannot go back and reconsider the rules in place at the time. The regulatory assets rule is similar, and in fact the result being proposed by the Applicant appears to be a one-sided approach to that rule, i.e. they get the tax benefit of the regulatory assets, but not the related tax cost.

0.2.16 In the result, it is submitted that the correct amount to be repaid to ratepayers is $2,841,943. To accede to the Applicant's request, the Board would have to conclude that, after the Applicant has already recovered from ratepayers $7.2 million more for PILs than it actually paid in respect of the period, it should benefit from an additional recovery of $5.6 million. Using the result that is consistent with the EB-2008-0381 principles still means that the Applicant overcollects to the tune of $4.4 million ($7.2 million overcollection originally, less $2.8 million refund today), but that is at least better than their proposal of $12.8 million of excess recovery.

0.2.17 ***Cost Allocation and Rate Design.*** SEC generally agrees with the proposals on cost allocation, subject to Staff's proposal to change the Streetlighting revenue to cost ratio in two steps, which we consider equally justifiable.

0.2.18 With respect to rate design, it is submitted that the fixed charge for GS>50KW, already above the Board's recommended range, should not be increased, but should remain at the 2010 rate. An increase would only exacerbate an existing problem.

0.2.19 ***Effective Date.*** We believe that the Applicant should be allowed to align their rate year with their fiscal year in 2011. Further, because there will almost certainly be a sufficiency, the effective date of new rates should be January 1, 2011, with a one-time payment to ratepayers at the time of implementation, in order to deal with the sufficiency in the stub period.

1 SUFFICIENCY OR DEFICIENCY?

1.1 *The Application*

1.1.1 The total deficiency/sufficiency resulting from the Application evolved over the course of the proceeding. It appears to us that the final as-filed sufficiency is $315,748. This is the deficiency of $116,379 set out in Exhibit K1.1, adjusted by $432,127 [the last line of the same exhibit] to reflect the new ROE.

1.1.2 While there may be further changes resulting from changes agreed to by the Applicant (some of which are discussed later in this Final Argument), the only reliable starting point presently before the Board is the sufficiency of $315,748**.**

1.2 *The Real Deficiency*

1.2.1 SEC does not dispute that, if the Application is accepted as filed and subsequently modified, the above sufficiency arises.

1.2.2 However, the Board and ratepayers look at a deficiency not only as a result of calculations, but also as a measure of how efficiently the Applicant has been managing its distribution business. Distributors with a higher deficiency are, all other things being equal, experiencing greater cost increases, and that needs to be explored to see if those increases could be contained better. Similarly, distributors with a lower deficiency, or with a sufficiency, are, all other things being equal, managing their business in such a way that cost increases are lower.

1.2.3 In this case, it is submitted that the intuitive conclusion from the sufficiency – successful cost containment – is not correct in this case.

1.2.4 Instead, SEC looks at this situation quite differently. We see the situation as follows:

(a) Over the period since rates were last set (2006), revenues have increased by about $6 million (10.7%). Revenues in 2006 Board-approved were $56.4 million [SEC #34, Table 1], and revenues at current rates in the revised Application are $62.4 million [K1.1 - $62.8 million less $0.4 million ROE adjustment]. This increase in revenues appears to be in part the result of four years of IRM increases, and growth in customer numbers and load over the period.

(b) Over the same period, controllable expenses have increased by about $23.1 million (41.5%). This is the result of large increases in two areas:

(i) An increase in OM&A of just over $8.4 million, or 61.3% [same references]

(ii) And increase of about $14.7 million in revenue requirement associated with five years of capital spending, and thus now a substantially higher rate base. This has three components. Interest costs have increased by about $3.3 million, and ROE has increased by about $2.7 million [same references]. As well, amortization has increased by about $8.7 million. In the case of the latter, this is calculated as the decrease in K1.1 relative to SEC #34, Table 1, $0.3 million, and the adjustment made by the Applicant to amortization rates, $9.0 million [Tr.2:17-18].

(c) The result is that controllable expenses have increased by about $17.1 million more than revenues.

(d) The Applicant has dealt with that increase in two steps:

(i) First, it has a windfall gain of about $8.5 million from reduced income and capital taxes between those in 2006 and those forecast for 2011. This reduces the amount that the Applicant is seeking as a rate increase.

(ii) Second, it has proposed a change to its amortization rates, reducing revenue requirement by about $9.0 million.

(e) The result is that, despite unusually high increases in costs, the Applicant is able to come to the Board with a sufficiency, instead of with the $17.1 million deficiency (27.4%) that it otherwise would have shown.

1.2.5 Before dealing with the relevance of this fact in the Board's deliberations, we should comment on two components of the above calculation.

1.2.6 The Applicant has sought to minimize the impact of the reduction in taxes in JT1.17. If the Applicant's calculation is correct, the windfall gain in taxes is about $6.8 million ($8.8 million in JT1.17, escalated for a further year of IRM, less $2.1 in 2011 PILs provision). While SEC believes that it is more correct to use the gross 2006 PILs provision, and escalate it for IRM increases, the end result is similar regardless of the calculation. Whether the windfall from taxes is $8.5 million or $6.8 million, the result is still a substantial amount that would otherwise be returnable to ratepayers, but instead is being retained by the utility to fund increased spending.

1.2.7 With respect to the change in amortization, SEC does not disagree with the Depreciation Study, nor with the new amortization rates. The point we are making here relates to apples to apples comparisons. On a comparable basis, the cost of rate base has increased by $14.7 million. The fact that an accounting change reduces that doesn't change the absolute amount of the operationally-driven increase. The money was spent. It is just being recovered from ratepayers, on the current proposal, over a longer period of time.

1.3 *Relevance*

1.3.1 The Board may legitimately ask how this is relevant. The simple answer is that, in a strictly formal way, it is not.

1.3.2 However, the Board regularly reviews rate applications, not just at a level of individual line items, but also from an overall perspective. If an LDC comes in with an application that shows its annual costs increasing at a rate that is almost four times the rate of customer/load growth, the Board will want to have an explanation for that. It is not normal, and not what the Board normally expects from the entities it regulates.

1.3.3 This is not to say that there can't be circumstances where cost increases at that high a level might be justified. It happens. But, the Board quite rightly looks very closely at utilities who claim that they can't keep their cost increases to normal levels. The burden of proof, as they say, is high. The utility must show why their circumstances are so unusual that cost increases can't be contained.

1.3.4 For example, as we will note later in these submissions, the Applicant is proposing to increase its OM&A spending by 61.3% over five years, We have not seen any other LDCs that claim this big an increase, and in our view the Board should be looking at the Application in this case to see what factors are causing the Applicant's cost increases to be so high relative to their peers.

1.3.5 In their Argument in Chief, the Applicant emphasizes [p. 15] their low OM&A cost per customer relative to their peers. SEC acknowledges this fact. However, having a good record of operations in the past does not mean a free pass when the Applicant is seeking an effective deficiency of 27.4%. Good performance should not mean increased spending. Utilities that perform well should be encouraged to continue to perform well.

1.3.6 One thing that is interesting about the Argument in Chief is what is not said. The Argument in Chief talks at some length about the cost pressures the Applicant faces, and characterizes virtually all of them as similar to those of other LDCs. The one exception is the high growth in the City of Brampton, which of course also generates higher revenues, and which in any case is shared by a number of other LDCs.

1.3.7 It is submitted that the Argument in Chief does not, however, point to any way in which the cost pressures on the Applicant are materially different from those on other LDCs. The reason it does not is that the evidence would not support such a conclusion. Yes, the Applicant has cost pressures. They are pressures shared with many other LDCs.

1.3.8 It is submitted that the onus and burden are on the Applicant to show why their controllable costs have effectively increased by 41.5% over the same five years that growth has been something less than 10.7%. The Applicant does not appear to have made any attempt to do so.

1.3.9 In SEC's submission, the Board should view the Application in the context of that substantial difference, and the failure of the Applicant to explain it.

1.3.10 ***IFRS.*** We note that the Applicant will shortly be moving to IFRS, and as a result there will be a rate increase of 6.5-7.0% (based on the deficiency included in the original Application). While that does not impact on the Test Year, it is submitted that the Board should consider that context when looking at the current Application.

1.3.11 Just as the $9.0 million reduction in revenue requirement proposed for the amortization rate changes is only a change (deferral) in the timing of payment of costs by the ratepayers, the $4.0 million or more increase in revenue requirement that we know is coming for IFRS will also be a change (acceleration) in the timing of payment of costs by the ratepayers. And, just as the IFRS change must be looked at differently than a cost increase from higher controllable expenses, so in our submission the amortization change must be looked at differently than a cost decrease accomplished through lower controllable expenses.

2 LOAD AND REVENUE FORECASTS

2.1 *Customer Forecast*

2.1.1 While SEC has not had an advance view of the customer forecast submissions of Energy Probe and VECC, we are aware of the changes that will be proposed in those submissions. We agree with those changes, including the reduction of 5 customers in the GS>50KW class and the increase of 5 customers in the Intermediate class.

2.2 *Load Forecast*

2.2.1 There are a number of issues associated with the load forecast, but SEC will follow its general practice of leaving that issue to VECC and Energy Probe, with the exception of the CDM adjustment. On all of the other issues, we are aware of the positions that will be put forward by VECC and Energy Probe, and we have nothing useful to add given their expertise in this area.

2.2.2 With respect to the CDM adjustment, it appears to us that the reduction of 64.0 GWh [Ex. 3/2/2, p. 4] to reflect the expected impact of CDM on load in the Test Year, is calculated incorrectly.

2.2.3 There are two parts to this issue. First, to the extent that the 64.0 GWh. is intended to reflect the Applicant's OPA and new programs in the Test Year, the estimate is mathematically incorrect. Using the normal calculation method (sometimes called the Rule of 78) for matters of this sort, the use of 64.0 GWh. would imply total CDM savings over the four years 2011 to 2014 inclusive of 640 GWh (64 in 2011, 128 in 2012, 192 in 2013, and 256 in 2014, for a cumulative total of 640).

2.2.4 The CDM target for the Applicant over this same period is 189.54 GWh. Clearly if the 64.0 GWh. adjustment is intended to reflect the Applicant's efforts, through OPA programs and those the Applicant is proposing, the adjustment is much higher than it should be.

2.2.5 Second, the Applicant may legitimately say that the CDM effects in the Test Year will include not just the results of their efforts, but also price elasticity, the results of programs and communications by others that affect their ratepayers, and general changes in the public's view of CDM. While that is all true, that should in our submission be irrelevant.

2.2.6 The basic load forecast developed for the Test Year includes trends from previous years. Those years include substantial and increasing efforts by the Applicant and others to implement CDM. Absent any evidence to the contrary, the Board should in our submission assume that the trend analysis already captures the overall levels of

CDM in the Applicant's franchise area.

2.2.7 Based on this analysis, SEC believes that the appropriate adjustment for CDM in the Test Year should be no more than 18.954 GWh. This (somewhat aggressively) assumes equal program results in each of the four years (and thus a cumulative total of 189.54 GWh.), and assumes that all of those programs are 100% incremental to the trend established in third tranche and other spending in the historical period. Thus, this amount is probably on the high side, but in our view the best number available given the evidence before the Board in this proceeding.

2.3 ***Other Revenues***

2.3.1 SEC has submissions on two aspects of Other Revenues.

2.3.2 The Applicant has advised that they have re-allocated about $57,000 from Miscellaneous Revenues to Account Setup and Collection of Accounts. However, those latter two lines do not appear to show a resulting increase (other than the normal increases that one would expect). It would appear to us that this adjustment has not been made correctly, and Other Revenues should be increased by $57,000 accordingly.

2.3.3 The Applicant has also proposed about $365,000 capital spending on part of their space that was previously used as a daycare [Ex. 2/5/7, p., 8]. The space will not be used by the utility, but the original plan was to spend some capital, then obtain rental income from the space. A tenant has not been found, and the Applicant agrees that the capital spending will only proceed if a tenant is found [Tr.1:44-45].

2.3.4 Under these circumstances, it is submitted that either a provision for rental income should be included in Other Revenues, or the capital spending should be removed from the capital plan. It is not appropriate, in our view, to have one without the other.

3 OPERATING COSTS

3.1 *Overall Level of OM&A*

3.1.1 The Applicant is proposing that rates be adjusted to increase the amount for OM&A from the amount currently in rates, $13,748,003 [SEC #34, Table1] to $22,176,435 [K1.1], an increase of 61.3%. Even relative to 2006 actuals, the increase is 37.3%. Either way, the increase is in our submission substantially in excess of a reasonable level for a utility with the characteristics of the Applicant.

3.1.2 SEC will have some specific comments on line items, and more detailed comments on personnel costs (the biggest driver of these increases), in the sections below. However, we also believe it is useful to look at the overall budget as an envelope, to see what levels are reasonable.

3.1.3 In our submission, a reasonable range for annual compounded OM&A increases over any extended period for a utility such as the Applicant is 2% to 5%. At a 2% annual compounded increase from 2006 actual spending, the 2011 budget would be $17.8 million. At a 5% annual compounded increase from 2006 actuals, the 2011 budget would be $20.6 million. It is SEC's submission that this is the maximum reasonable range for a 2011 OM&A budget for the Applicant - $17.8 million to $20.6 million.

3.1.4 Within that range, it is more difficult to assess what a reasonable level would be. Some of the considerations could be the following:

(a) OM&A spending in 2010 was, at June 30th, about 2.1 % above 2009 [Tr.1:52]. This suggests that annual spending increases at the lower end of the 2-5% range might be appropriate.

(b) Average increases in OM&A for the years 2006 through 2009, the years actuals are available, are about 3.35% per year compounded [SEC #32]. This suggests something in the middle of the range.

(c) The Applicant has had a low OM&A per customer relative to its peers in the past, which sometimes means that there is underspending, and therefore pressure to increase spending to ensure all work is done properly. This suggests something a little higher in the range.

(d) The compounded annual growth rate (using revenues as a proxy) is about 1.9% (10.7% over five years), and the inflation rate over the same period has averaged a similar amount. Even if the two were additive, the result would be a 3.8% annual increase in OM&A.

3.1.5 The above analysis suggests that something in the 3% range, compounded annually for five years, would approximate a reasonable budget level in 2011, i.e. about $18.7 million.

3.1.6 Below we propose a reduction in personnel costs of about $1.7 million, and a reduction in other costs of about $0.8 million. That would net Test Year OM&A of about $19.7 million, or about 4.1% per year (22.0% over five years). (We have also included a recommendation to increase OMERs, but in our view that is outside of this top-down analysis.)

3.1.7 In our submission, that result, given that it is $1 million higher than the top-down approach would suggest, should be more than adequate as an OM&A budget for 2011. It is therefore submitted that the appropriate OM&A budget for the Test Year, excluding depreciation and PILs, is $19.7 million.

3.1.8 We note that this would still represent an increase in the OM&A component of rates of about $6.0 million or 43.8% over five years.

3.2 ***Specific Components of OM&A***

3.2.1 ***General.*** We will limit our submissions on specific OM&A components to the inclusion of MDM/R costs in the Test Year, and the proposal to defer announced OMERs increases. The primary focus of our review, aside from the top-down approach, is the FTE increases, dealt with in the next section.

3.2.2 ***MDM/R Costs.*** The Applicant has included $758,949 [Tr.1:54] in Test Year OM&A relating to MDM/R costs that are expected to be billed from IESO or some other entity.

3.2.3 In our submission, this issue, which will affect all distributors, is brought forward prematurely in this proceeding. No charges from IESO or anyone else to distributors have been approved by this Board (as they must be), and to the best of our knowledge no application has been filed or even prepared for this purpose. At some time in 2011 an application may be filed, but we would be surprised if approved rates for this item are in place much before the end of the year, given the current status.

3.2.4 If and when the Board approves rates for this service, many distributors will be affected, most of them in the middle of an IRM term. In our submission, the most efficient way to deal with this is to allow the Board to make a decision about the impact of these charges on all distributors at the time they are approved. This would promote consistency, and avoid the need to consider the issue in every cost of service proceeding (and perhaps special applications by other LDCs) until the matter is fully resolved.

3.2.5 It is therefore submitted that this amount should be removed from OM&A, with the understanding that some amount will probably be charged in the future, and the Board will at the time have to consider the appropriate accounting and ratesetting response to those charges.

3.2.6 ***OMERS Cost Increases.*** On the other side, the Applicant expects that there will be a total of about $1.5 million of additional payments to be made to OMERs over the next four years. We have read the submissions of Board Staff on this issue [p. 12-13] and we agree with their analysis, i.e. $375,000 should be added to annual OM&A to reflect this additional cost.

3.3 ***Human Resource Costs and Levels***

3.3.1 ***General.*** The biggest driver of the high OM&A increase appears to be the expansion of the workforce, particularly in 2011. The increase from 2006 actuals to 2011 budget appears to be 39 people, an increase of 20.3% over five years, and the increase in overall compensation appears to be $5.6 million, i.e. 33.3% [all Staff #20, p. 2]. 69% of this increase in compensation - $3.9 million - is allocated to OM&A.

3.3.2 In our submission, the increases in the workforce have not been justified, and the budget should reflect a more reasonable level. As we note below, the result is in our view a reduction in OM&A of just over $1.7 million. This should be allocated 100% to OM&A, as discussed further below.

3.3.3 ***Workforce.*** The Applicant's proposal to increase its FTEs by 39, of which 20 are listed for 2010 and 2011, has not been justified.

3.3.4 The Applicant seeks to justify the FTE increases by a chart [JT1.14] that shows the reason for each new position. That chart, which identifies 48 new positions (it goes back to 2005), includes 35 justified by increased workload, 4 as Replacements, 7 for New Programs, and 9 for Succession Planning, with the excess of 7 explained by some positions with more than one justification.

3.3.5 With respect to the New Programs, it is submitted that these are in all cases simply another name for increased workload. While it is true that Smart Meters, for example, are a "New Program", the reason for the additional staff is a claim that the program means increased workload.

3.3.6 With respect to the Replacements, the Applicant's witnesses in cross-examination ultimately had to admit [see, e.g. Tr.1:105-6] that these are positions that had been vacant for some time, and were being filled due to increases in workload. Since none of these positions are treated as downward adjustments in the JT1.14 table, logically of these positions must have been vacant since 2006, even though they are being filled four or five years later. In our submission, this is not a replacement. This describes a new position, and the only justification offered has been increased workload.

3.3.7 Finally, the Applicant admits that they do not have a succession plan [Tr. 2:3], yet every single one of the positions justified by succession planning is proposed to be filled in 2010 or 2011 [JT1.14]. It appears to us that the real reason for these new hires, to the extent that they are actually occurring (see below), was unearthed by Mr. Millar in cross-examination. The Applicant's witness Mr. Gribbon made clear that, while these individuals are hired for succession planning, they are still productive, because "Our volume of work continues to increase as our customer base grows and our calls increase, our fleet grows. We continually need more people." [Tr.1:133]

3.3.8 In our submission, the "succession" rationale, unsupported by any succession planning exercise, is merely another reason to add more personnel to meet the increasing workload.

3.3.9 All of this leads us to conclude that all of the 39 additional FTEs have been justified primarily because of increasing workload.

3.3.10 In our submission, a mature utility that has grown by about 10% over the last five years should not, unless there are extreme circumstances, need to increase personnel by more than 20%. While there may in some cases be new regulatory and other requirements (like smart meters), there should also be efficiencies gained, and normal productivity improvements due to economies of scale. We would normally expect FTEs to increase roughly with customer growth, or at a lesser rate.

3.3.11 ***Actual Hiring.*** This leads to the second concern we have with the FTE increases. It appears that at least some of the forecast hiring that should have happened so far has not in fact taken place.

3.3.12 SEC's cross-examination at Tr.2:6-7 is instructive in this regard. JT1.14 lists 14 positions to be filled in 2010. In a quick review of that forecast in December, the Board learned that at least seven of those 2010 positions had not been filled. While the witness stated that many of them were "in process", it was surprising to find that half of the year's hiring was not going to happen in the year.

3.3.13 In our submission, this is clear evidence that the forecast additions for 2010 and 2011 are overstated.

3.3.14 ***Appropriate FTEs***. Based on the above analysis, our conclusion is that the OM&A budget for the Test Year should be set on the assumption that the increase in FTEs from 2006 actual is no more than the customer growth in the same period. As a result, in our submission the maximum increase in FTEs should be 21, representing the highest possible customer growth number that could be applied.

3.3.15 Based on the average cost per employee of $96,695 [see Staff Argument, p. 9], this reduction of 18 FTEs would reduce total compensation in the Test Year by $1,740,510.

3.3.16 While some portion of this could reasonably be allocated to capital, it is also true that additional FTEs cause other costs to increase, over and above the actual compensation, such as space, equipment, support, training, etc. The normal uplift of compensation to fully-loaded costs is 40-60%. We propose that, rather than trying to calculate the loading for the Applicant, it may be simpler to allocate the entire adjustment in compensation budget to OM&A, thus effectively producing a similar result.

3.3.17 It is therefore submitted that OM&A should be reduced by $1,740,510, to reflect a more reasonable FTE level in the Test Year.

3.3.18 ***Compensation Levels.*** No additional submissions.

3.4 ***Income and Other Taxes***

3.4.1 We have had the opportunity to review the submissions of Energy Probe respect to taxes, and we adopt both the analysis and the conclusions in those submissions.

3.5 ***Depreciation Expense***

3.5.1 Although we have noted earlier that the change in amortization rates has an impact on the effective deficiency in this proceeding, we agree that the change is appropriate. While it means that ratepayers pay the same amounts on a deferred basis, plus an increased cost of capital, the new rates appear to us to be more rigorously determined than the old rates.

4 CAPITAL EXPENDITURES and RATE BASE

4.1 *Overall Amount of Rate Base*

4.1.1 With the exception of the comments below on the GEA spending, and the recalculation of working capital, SEC has no submissions on the proposed capital spending and rate base for this Applicant. The Applicant is a high growth utility, and it has followed a fairly consistent capital spending plan for a number of years. That does not appear to be changing in any material way for the Test Year.

4.2 *Green Energy Act Expenditures*

4.2.1 The current proposal with respect to the proposed GEA expenditures appears to be modeled on the smart meter regime originally used, i.e. [Tr. 2:28]:

(a) A rate adder of $163,967 per annum to recover the revenue requirement impact of the currently proposed spending.

(b) A deferral account to record the spending as incurred.

(c) No finding of prudence with respect to the spending until the deferral account is cleared.

(d) A determination by the Board in this proceeding as to the appropriateness of the direct benefits proposed [Tr. 1:26].

4.2.2 With respect to the direct benefits, we have reviewed the submissions of Board Staff and agree with their conclusions.

4.2.3 With respect to the proposal to create a deferral account, and the proposal to defer any prudence review, we agree with the Applicant.

4.2.4 With respect to the proposed rate adder, we have one concern. It would appear to us that the Applicant is proposing to recover 100% of these costs from ratepayers (i.e. a rate adder based on 100% direct benefits), and then to refund whatever is overcollected once the direct benefits percentage has been determined.

4.2.5 In our submission, this is inappropriate. The Board should, in our view, make a decision today about the breakdown between local and socialized costs (along the lines proposed by Board Staff), with the understanding that any such finding is provisional and will be finalized when the account is cleared. In the meantime, the rate adder should be based on the proportion that the Board believes will ultimately be borne by the local ratepayers.

4.3 *Working Capital*

4.3.1 SEC has reviewed a draft of the submissions of Energy Probe on the calculation of working capital, and believes that analysis correctly sets out how working capital should be recalculated consistent with Board policy and the facts established in this proceeding.

5 CAPITAL STRUCTURE AND COST OF CAPITAL

5.1 ***Capital Structure***

No additional submissions.

5.2 ***Return on Equity and Short Term Debt***

No additional submissions.

5.3 ***Long Term Debt***

5.3.1 The Applicant proposes a cost of long term debt of 6.95% representing its note to its parent, Hydro One Networks.

5.3.2 We have had a chance to review the submissions of Board Staff with respect to long term debt, and we are aware of the positions of VECC and Energy Probe. We do not take the same position.

5.3.3 In our submission, the question of the interest rate to be used for the Applicant's long term debt can be simplified, because the sole lender to the Applicant is Hydro One Networks Inc. The appropriate interest rate to be used is, it is submitted, the weighted average cost of long term debt of the lender, the parent company.

5.3.4 The essence of the Applicant's argument is that the current 6.95% note to the parent is back to back with a 2001 public debt issuance by the parent, some of which was "allocated" to the Applicant.

5.3.5 This is, in our view, not the correct way to look at it. Money is not fungible, and this debt issuance is not in any way a flow through. The debentures issued by the parent are required to be included in the weighted average cost of debt of the parent. In the recent Hydro One Transmission case (EB-2010-0002), that weighted average cost of long term debt for calendar 2011 was determined to be 5.67% [Page 48 of that Decision].

5.3.6 In our submission, the Applicant does not borrow independently of the parent Hydro One Networks, and as a result their cost of debt should be the same as the parent.

5.3.7 We note that, if this is not the case, the effect is that the parent Hydro One Networks, borrowing at a weighted average cost of 5.67%, is then re-lending to the Applicant at 6.95%, and making a profit on the way through. That profit, based on the $143 million of debt from 2001 issued at 6.95%, would be $1,830,400. In our submission it is not appropriate for a parent company that is a regulated entity, and has a regulated cost of long term debt, to earn a speculative profit by re-lending to a regulated subsidiary at a higher rate.

5.3.8 It is therefore submitted that the cost of debt of the Applicant that is recoverable from ratepayers should be reduced by 1.28% (6.95% minus 5.67%) multiplied by 56% of the rate base as finally determined. Based on the rate base as filed, that reduction would appear to us to be $1,974,864, but adjustments by the Board, for example to working capital, would reduce that amount.

6 DEFERRAL AND VARIANCE ACCOUNTS

6.1 *Amounts, Disposition and Continuation of Existing Deferral and Variance Accounts*

6.1.1 ***General.*** Our submissions on this issue, aside from Account 1562, are limited to LRAM/SSM. On that issue, we were provided with a draft of the submissions of VECC, and we concur with their analysis and their conclusions.

6.2 *Account 1562 – Deferred PILs*

6.2.1 ***Timing of Application.*** At the highest level, it is our view that this Board panel should not make a determination on the clearance of Account 1562 for this Applicant. Although in our analysis we conclude that the clearance would be a credit to ratepayers (see below), we believe that the request is premature.

6.2.2 The Board has established a generic Deferred PILs proceeding, EB-2008-0381, to deal with the common issues associated with 80+ LDCs that have balances in Account 1562 relating to the years 2001 to 2006. A lot of time and effort has gone into that process, which is in the final submissions phase right now. Completion of the process is likely within the next few months. The Applicant has been an active participant in that process, as has SEC.

6.2.3 Once the generic proceeding has concluded, individual Board panels will be in a position to hear applications by individual utilities to clear this account. Utilities will, we expect, have many proposals for why aspects of the generic proceeding that are unfavourable to them should not apply, and they are free to make those proposals. The individual Board panels hearing those cases will then have to deal with those proposals on their merits.

6.2.4 However, with the generic proceeding completed, the individual Board panels will be in a position to review the entire record of that proceeding, including the final Decision, and see what issues have already been considered, why they were resolved in particular ways, and how the various positions were considered by the Board in light of the overall context.

6.2.5 What the Applicant is asking of the Board in this case is to consider the same issues, in parallel, in effect reinventing the wheel. In our view, these issues are difficult enough, without having to go through them before multiple Board panels, with the potential waste of time and effort, and the high possibility that different Board panels would reach inconsistent conclusions.

6.2.6 It is therefore submitted that the Board should not make a determination on the Applicant's Account 1562 at this time. Whether the Board simply declines to make that determination because it is premature, or establishes a second phase of the proceeding to deal with that remaining issue later, both of which would be appropriate responses, in our view the Board should not make a determination without having the benefit of the completion of the EB-2008-0381 proceeding.

6.2.7 ***Interest Clawback.*** In the event that the Board does decide to determine clearance of this account at this time, the two main issues are the application of the interest clawback, and the treatment of regulatory assets.

6.2.8 With respect to the interest clawback, we have reviewed the analysis by Board Staff, and in general we agree with most of it.

6.2.9 However, our approach to this issue is much simpler. In our submission, the EB-2008-0381 Board panel has already made a general determination, after hearing extensive submissions from all parties, on the issue of principle that underlies the interest clawback issue.

6.2.10 In the Deferred PILs proceeding, there was a debate at the outset about whether the role of the Board now is to implement the rules that the Board had put in place in 2001 through 2006, or whether it is appropriate now for the Board, with hindsight, to determine the most fair and reasonable method of truing up PILs over that period.

6.2.11 Of course, those two extremes – follow the existing rules, good or bad, vs. make up new rules that produce the fair result – have between them many gradations. For example, there were many issues about which statements or implied statements by the Board in 2001-2006 were “rules”, and which were not. Or, what if a Board spreadsheet, for example, contained an obvious mathematical error, inconsistent with the general principles being implemented? Or – and this was very common – what if the rules contemplated certain types of transactions, but did not expressly deal with all variations on those transaction? These are but a few of the many nuances that arose between the “implement the rules” paradigm, and the “get the right answer” paradigm.

6.2.12 Although there were these many nuances, the Board did make a decision on the basic principle that must be applied. Contrary to the position taken by many parties (including SEC), but accepting the position of most utilities (including CLD and EDA) the Board determined that the paradigm to be employed is the “implement the rules” paradigm [Decision with Reasons, December 18, 2009]. To review those rules and “fix” them, the Board determined, would be retroactive ratemaking, and inappropriate.

6.2.13 A key quote from that Decision [p. 5-6] makes the Board’s view clear:

> *“The Board agrees that the appropriate approach is a review of the account in terms of whether the distributors applied the methodology appropriately as the methodology existed at the time.* ***The Board finds***

> ***that it would be inappropriate to now change the methodology which was used in the past.*** *This would only be appropriate if the Board had clearly signaled that the methodology itself would be subject to future revision on a retrospective basis. The Board made no such pronouncement. While the Board's methodology may not have been formally tested and adopted through a rates proceeding, the tools clearly were sanctioned by the Board and formed the basis on which distributors were expected to operate. It was reasonable to expect that any methodological changes would be prospective in their application." [emphasis added]*

6.2.14 In our submission, unless this Board panel declines to apply the same principle to the Applicant's case, it is determinative of the matter of the interest clawback. It is common ground that the interest clawback was included in the methodology of the Board for Account 1562 during 2001-2006 [the Applicant admits this at AIC p. 8]. The fact that the 2006 EDR Handbook comments on it with some doubt, if that is true as the Applicant alleges in its Argument in Chief, is completely irrelevant. The Board has considered whether it should go back and "fix" things like this. It has decided that it will not.

6.2.15 It is important to note that it was the ratepayers who sought to review the methodology for fairness, and it was the utilities who opposed that and won. The reason that fact is relevant here is seen in SEC #40. In section (e) of that response, it can be seen that in the period of Account 1562, the Applicant collected $39,660,297 from ratepayers to pay PILs (the "PILs proxy"). Taxes actually paid relating to the same period were $32,468,553, meaning that the Applicant collected $7,211,744 more in rates for PILs than it paid in taxes.

6.2.16 The ratepayers, of course, would have liked to go back to the methodology for that period, and adjust it to ensure that the true-up actually returned to ratepayers the amounts they overpaid in PILs proxy. The Board declined to allow that, as seen in the quote above.

6.2.17 Now, this Applicant argues that, having collected at the time $7.2 million more than it needed to, it should collect a further $5.6 million from ratepayers by retroactively adjusting the methodology that applied during that period. The ratepayers would not get the benefit of reviewing the fairness of the methodology from their point of view (because the Board has determined that they cannot), but the Applicant, already enjoying an over-recovery windfall, would get a further amount by doing exactly that – challenging the fairness of the methodology.

6.2.18 In our submission, the Applicant's argument on this is completely unsustainable, and flies in the face of both the threshold decision in EB-2008-0381, and common sense. The Board should reject it completely. Since the interest clawback was part of the methodology, the principle states that the clawback must apply. If the principle determined in EB-2008-0381 is not to be applied, then in our submission it should be open to the ratepayers to challenge other aspects of the methodology, with a view to getting a true-up mechanism that actually trues up the PILs proxy collected to the PILs paid.

6.2.19 ***Regulatory Assets.*** The question of the regulatory assets is a more complicated one, but in principle resolves to the same result.

6.2.20 The transitional costs incurred by LDCs during market opening were mostly deductible for tax purposes at the time. Some utilities took those deductions, and some did not. Some utilities, although deducting them for tax purposes, held them as regulatory assets on their balance sheets (i.e. they took the tax deduction, but no deduction for accounting purposes), while others treated them as expenses for account purposes at the time. Wherever tax deductions were taken during the period 2001-2006 for these expenditures, the actual tax liability was less than the PILs proxy, and a potential Account 1562 difference could have been created.

6.2.21 Once it became clear that transition costs would be recoverable by utilities, the Board had to deal with how to handle these various tax treatments. As Staff correctly points out in their submissions, the rule for Account 1562 was that if an Applicant took the tax deductions during the period 2001-2006, then on the Account 1562 calculation it would have to reduce its taxable income by a like amount, thus increasing the amount by which the PILs proxy could be greater than the tax paid.

6.2.22 The Applicant did not follow this methodology. Instead, it took the tax deductions but calculated Account 1562 as if the higher taxable income (without the deductions) was correct, and therefore as if the tax payable in those years was higher than it really was as well.

6.2.23 In our submission, this is not only inconsistent with the Board's methodology, but also asymmetrical in its treatment of the tax costs and benefits. We agree with Staff that it should not be permitted.

6.2.24 ***Conclusion.*** As a result of our analysis of these two issues, it is submitted that if the Board wishes to clear Account 1562 at this time, the correct amount to be refunded to ratepayers from Account 1562 is set out at page 57 of Staff Final Argument, i.e. $2,841,943.

6.3 New Accounts

6.3.1 ***LPP Settlement Account.*** It appears that the Applicant has withdrawn its request, given the EB-2010-0295 proceeding that is currently underway. Whether or not it has in fact been withdrawn, it is submitted that the account is premature.

6.3.2 ***IFRS Accounts.*** It is our understanding, based on the Applicant's Argument in Chief, that the request for these three accounts has been withdrawn, and therefore we have no submissions.

6.3.3 ***MDM/R Costs Account***. We agree with Staff at p. 40 of their Final Argument, where they note that the Board in the EB-2010-0209 decision denied creation of a deferral account for MDM/R costs. It is submitted that this Board panel should maintain consistency with that decision unless there is evidence that the current situation is materially different. It is not, and therefore, no deferral account is appropriate.

7 COST ALLOCATION

7.1 *General*

7.1.1 We agree that the proposals of the Applicant with respect to changes in revenue to cost ratios are appropriate and reasonable.

7.1.2 We note that Staff, in their Final Argument [page 35], have suggested that the movement of the Streetlighting class to the Board's RTC range should take place over two years rather than immediately. SEC believes that this is also a reasonable alternative to the proposal made by the Applicant. In our view, either the original proposal, or the Staff alternative, would produce an acceptable result**.**

8 RATE DESIGN

8.1 *Monthly Fixed Charges*

8.1.1 ***General.*** We have no comments on rate design, except with respect to the GS>50KW monthly fixed charge.

8.1.2 ***GS>50 KW Class.*** The Applicant proposes to increase the monthly fixed charge for GS>50KW, even though it is already above the maximum of the range.

8.1.3 It is our submission that the fixed charge ceiling for the GS>50KW class should be respected. The basic rule is that if any movement of the charge would cause it to move outside of the ceiling, it must stop at the ceiling. In the same way, a fixed charge that is already outside of the ceiling should not be made worse by an increase. While we realize that the regularization of fixed charges is a policy matter that may be considered in the future, at the very least it is, in our view, not appropriate for a utility to exacerbate an already bad situation by moving the fixed charge further away from the Board's recommended range.

8.1.4 Therefore, it is submitted that the fixed charge for GS>50KW should be left at the 2010 level, and any revenue shortfall should be made up in the volumetric charge for the class.

9 OTHER MATTERS

9.1 *Effective Date*

9.1.1 The Applicant is seeking an effective date of January 1, 2011. That raises two questions. First, should the Applicant be allowed to align their rate year with their fiscal year? Second, what should be the effective date of new rates arising out of the Board's decision, regardless of the ultimate rate year ordered?

9.1.2 On the question of alignment with the fiscal year, SEC is on record as saying that, in most cases, and subject to handling any transitional impacts, the fair result is to allow the LDCs to collect rates over the period to which they relate, i.e. their fiscal period. The existing legacy structure is, in our view, an anomaly that should be corrected if possible.

9.1.3 The instant situation appears to us to be the perfect one in which to do that, in that there can be no material adverse impact on ratepayers. There is at the very least a small sufficiency, so the immediate transitional cost of alignment is minimal. Further, the impact in the next three IRM years will also be small, assuming the IRM adjustment is small, meaning that the first time there can be any significant impact is in 2015. We therefore believe that this is the optimum situation for rate and fiscal year alignment.

9.1.4 The second point is more difficult. The Applicant did not file their Applicant early enough to expect rates in place by January 1, 2011. A more reasonable expectation would have been March 1, 2011, and if there was a deficiency it would not be reasonable for them to expect to recover the January and February components, since the late filing was within their own control.

9.1.5 The situation is different here, since there is likely a sufficiency, and the impacts are not symmetrical. If rates are deferred until March 1, 2011, then the Applicant will benefit from the late filing in the amount of the sufficiency otherwise applicable to January and February. It is not appropriate that they benefit from their own delay.

9.1.6 Therefore, our submission is that the effective date for new rates should be January 1, 2011. Assuming that the actual implementation date is later, the Board should in our view order a one-time payment of the sufficiency from January 1st to the date of implementation, allocated to customers on the basis of distribution revenues.

9.2 ***Costs***

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

All of which is respectfully submitted.

Jay Shepherd
Counsel for the School Energy Coalition