EB-2009-0096

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 Networks Inc. pursuant to the *Ontario Energy Board Act* for an Order or Orders approving just and reasonable rates for the delivery and distribution of electricity.

FINAL ARGUMENT
ON BEHALF OF THE
SCHOOL ENERGY COALITION

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0 GENERAL COMMENTS

0.1 *Introduction*

0.1.1 On July 13, 2009 Hydro One Networks Inc. filed an application for new distribution rates commencing January 1, 2010 and January 1, 2011. The application has been updated a number of times throughout the proceeding, most notably to increase the return on equity as a result of the Board's December 11, 2009 Report on the Cost of Capital.

0.1.2 The application as revised [J4.4] identifies a 2010 base revenue requirement of $1,194 million, resulting in a 14.1% average rate increase. The 2011 revenue requirement sought is $1,293 million, a further 11.6% average rate increase. For some customer groups, including schools, the rate increases proposed are considerably more.

0.1.3 This is the Final Argument in this matter on behalf of the School Energy Coalition. In this first section, we will discuss an overriding issue that we believe has come to the fore in this proceeding. The sections following are numbered to be consistent with the Board-approved Issues List.

0.1.4 In preparing this Final Argument, we have benefitted from a review of the very thorough and thoughtful Staff Submission dated February 1, 2010. That was most helpful, and having it in advance has simplified this argument. We also had an opportunity to review the final argument of GEC, filed on February 2, 2010, and a draft of the CME argument, circulated on February 4, 2010. These were both also quite helpful in developing these submissions.

0.2 *The Unique Position of Hydro One*

0.2.1 The Board will have been conscious throughout this proceeding of the unusual level of frustration that ratepayer groups are experiencing with Hydro One Networks. There is always a little tension between regulated entities and ratepayer groups when a matter gets to the oral hearing, but in this case it was clear that this goes well beyond the norm.

0.2.2 The Applicant has always maintained that they are unique, because of their size, their geographic coverage, their dual (transmission and distribution) responsibilities, and their direct reporting to the Minister of Energy. This is, we believe, reflected in the way the Applicant approaches the regulatory process.

0.2.3 In this period of potential rapid expansion of spending, we believe that the Board should consciously assess whether it is satisfied with the approach Hydro One takes to the regulatory process. If it is not satisfied, it should in our view take steps, as soon as possible, to cause Hydro One's relationship with the regulatory process to improve.

0.2.4 The symptoms of this "problem" (assuming, as we believe, that it is one) have been the subject of numerous comments by stakeholders over the last few years, and include, but are by no means limited to:

(a) An established and very public policy at Hydro One of **refusing to engage in Board-mandated ADR processes**, with the limited exception of willingness to allow intervenors to accept Hydro One's evidence on an issue unchallenged, and thus treat it as settled. Hydro One has stated in many public ways that it simply will not negotiate its applications, but will let the Board decide.

(b) Hydro One's **refusal to follow the 3rd Generation IRM process** of a rebasing year followed by three IRM years. The only IRM year it has "tried" was its 2009 capital module proposal. When that was not successful in, in effect, allowing them "cost of service lite", they turned to a multiple forward test year approach. This is an approach that the Board rejected in the 3rd Generation IRM process, and is particularly problematic this year. We will comment later on our specific recommendations for the Board in responding to this approach for 2011.

(c) The now too common response of Hydro One to Board directions and requirements, i.e. **declining to follow the Board's instructions**. We will discuss later some examples of this concern in this proceeding, but it goes beyond those examples. When the Board gives a direction to Hydro One to do something, it currently can have no assurance that Hydro One will comply with that direction.

(d) The several instances, including at least two in this proceeding, of Hydro One **asking a Board panel for something that has been asked and denied by a previous Board panel.** We are not referring to situations in which the circumstances have changed, or there was a lack of evidentiary basis which has been corrected. We are talking about what appears to be "forum shopping", i.e. asking for something repeatedly until the utility finds a Board panel that is sympathetic to the request.

(e) Hydro One's **use of stakeholdering not as a method of dialogu**e with its ratepayers, but rather as a method of excusing its unwillingness to follow Board directions, or as a method of supporting its own policies (as opposed to developing new ones). A good example is the density study, jettisoned despite a Board directive because Hydro One found that those of its stakeholders who opposed the study in the first place continued to oppose it, thus "justifying" a delay in doing what the Board had directed.

0.2.5 The theme that appears to run through these examples – and there are more that we're sure the Board can think of – is that of a utility that is uncomfortable with the limits that regulation places on their freedom**.** We are concerned, and we think the Board should be concerned, that its authority and policies are not being internalized by the province's largest distributor. Identifying the reasons for this should, we believe, be important to the Board.

0.2.6 We agree with Hydro One that they are unique, a "special case", but not for the reasons that they offer.

0.2.7 What we observe is that Hydro One is actually the only distributor of electricity in Ontario that has a pre-existing relationship with the Board. For every other distributor, their relationship prior to market opening was with Ontario Hydro, not the OEB. But for Hydro One, when it was still Ontario Hydro, there were two aspects of its relationship with the Board that may be relevant today:

(a) When Ontario Hydro came in for its annual review, it was not as a regulated entity, because the Board did not have power to either set rates or impose obligations on the utility. Rather, the Board's role was to make recommendations. Everyone who was involved then, fifteen years ago and more, can remember the reports that Ontario Hydro would give back to the Board, advising the Board of their decisions on whether to follow each Board recommendation, or not.

(b) With respect to electricity distribution, Ontario Hydro had the role that the Board has today, as the "regulator" setting electricity distribution rates for what were then the MEUs. Now, those same LDCs (80 of them instead of 360) are regulated by the Board, so the role has been transferred.

0.2.8 In our view, these pre-existing relationships with the Board (as unregulated entity, and as predecessor regulator) may be colouring the approach Hydro One is now taking to the Board's regulatory authority and responsibilities. This is a concern not for reasons of "respect" or anything like that, but rather because the Board has been given a statutory responsibility with respect to electricity distribution, and it can only meet that responsibility if distributors understand and accept their role and the nature of the relationship.

0.2.9 It is therefore submitted that the failure of Hydro One to fully accept the position of regulated distributor is a barrier to the Board's successful delivery of its legislated responsibilities.

0.2.10 What to do about this is not a simple matter. Sure, the Board could, in its decision, "lecture" Hydro One on its failure to do things that the Board has told it to do. The Board has done that in the past but, frankly, we have seen little evidence that the Applicant has internalized the message. What we will suggest, in these submissions, is that the Board make clear that there will be real, tangible consequences if Hydro One does not respond appropriately to Board directions and policies, and does not adopt a more constructive approach to the regulatory process.

0.2.11 So, for example, we will propose that, if the Applicant is directed to do a study, and elects not to do so, or to do only part, or it does not deliver on the spirit of the Board's direction, it will have its revenue requirement reduced by a predetermined amount. Call it a penalty, perhaps, but either way it is a message that the regulator's directions must be respected. The Applicant can, of course, file a Motion for Review citing changed circumstances, if it really feels it cannot do as directed. What it should not do is unilaterally decide to ignore a Board direction.

0.2.12 Similarly, we will propose that – particularly in this year in which the economic assumptions underpinning Hydro One's planning are so out of date – the Board expressly not approve any rates or revenue requirement for 2011. Hydro One will therefore have to choose to either come back in with updated information for 2011 cost of service rates, or accept the IRM formula that applies to every other utility in the province.

0.2.13 In this regard, we will also propose that Hydro One be allowed to recover in rates regulatory costs associated with one cost of service proceeding every four years. If they seek cost of service rates more often, the shareholder should pay the incremental cost of ignoring the Board's IRM process.

0.2.14 These are but two examples of our more general point. In our submission, the Board should in this proceeding send a clearer and more pointed message to the Applicant that it must change its attitude to the regulatory process. Hydro One should understand that, bigger and more complex though it is relative to other distributors, it remains a regulated electricity distributor, and any differences between how the Board treats Hydro One and how the Board treats the other 79 distributors will be the exception, not the rule.

0.2.15 If Enbridge and Union, both just as big and complex as Hydro One, can accept their regulated role, and by their actions assist the Board in meeting its responsibilities, we see no reason why the same cannot be expected of this Applicant.

1 ADMINISTRATION

1.1 *Response to Board Directions*

1.1.1 We have commented in Section 0.3 above on the general problem of Hydro One's persistent failure to respond appropriately to Board directions. Where specific prior directions are relevant to individual issues below, we have dealt with those directions in the context of those issues.

1.2 *Economic and Business Planning Assumptions*

1.2.1 The economic and business planning assumptions of the Applicant in this case are out of date. As a result there is a significant danger that the forecasts on which the revenue requirement requested is being based are fundamentally incorrect. That is particularly true with respect to 2011.

1.2.2 The Applicant has built this application on economic and business planning assumptions from the fall of 2008 [A-14-1, App. A]. In general, this is understandable, since the combination of the utility's internal planning cycle, and the regulatory process, build in a delay that cannot be avoided. In this case, however, there are three factors that make that unfortunate but understandable delay problematic:

(a) The fall of 2008 was a period of great economic and business volatility and uncertainty, in which most forecasters had considerable difficulty in projecting what would happen over the next 3-6 months, let alone a couple of years. No-one today would voluntarily go back and use forecasts from the fall of 2008 and expect them to be remotely accurate.

(b) Hydro One is presenting to the Board a utility whose business is not stable, but rather is in a state of significant change, in part due to major changes in electricity policy, but also due to their own approach to managing their business.

(c) The application attempts to forecast, not one forward test year, but two.

1.2.3 With respect to 2010, we see no way around the use of old and probably unreliable forecasts. It would have been of significant benefit to the Board if Hydro One, when asked to update some of its assumptions with more recent information [e.g. at H-3-3 and at Tr3:104], had elected to do so, but that did not happen. The Board is stuck with the assumptions provided, even if they are likely wrong. While we will propose some common sense adjustments to forecasted figures in other parts of these submissions, in general we see nothing the Board can do about the assumptions in this case. In a normal year, the assumptions would be fine. This year, they probably skew the revenue requirement in both predictable and unpredictable ways.

1.2.4 On the other hand, the Board can do something about the forecasts for 2011. What Hydro One has requested – a multiple forward test year approval – is contrary to the Board's stated policy on distribution ratemaking. Although it has been done before (in the Toronto Hydro case), it is not the Board's practice, and Hydro One has not, in our submission, provided any evidence to show why their situation is different from the normal situation to which the general 3rd Generation IRM policy applies.

1.2.5 But beyond that basic objection to the multiple forward test year approach, there is a particular problem because of the weakness of the economic and business assumptions. Simply put, the assumptions underlying the 2010 forecasts are obviously weak, and those underlying the 2011 forecasts are weaker still. In our submission, the result is that the forecasts for a 2011 test year are not sufficiently strong to form the basis of a revenue requirement determination by this Board.

1.2.6 We note that this is not just a case of a utility marching forward in a stable manner, carrying on the same business year after year and adjusting to small variations in customer and load growth, policy directions, etc. This is the case of a utility that, by its own evidence, is coping with massive policy and economic change. In that situation, it appears to us that the Board should approve the shortest period of rates necessary, which in this case is 2010 only.

1.2.7 The interesting result of such a decision is this. Hydro One is then put to a choice. It can accept the Board's IRM process for 2011, a rate increase of about 1% (plus perhaps an incremental capital module, which may be engaged by GEP spending), or it can apply for 2011 rates on a cost of service basis, but with more up to date and thus more defensible economic and business planning assumptions. Either situation is, in our submission, better than a 2011 test year based on a cost of service that has no solid foundation.

1.2.8 In passing, we should also note that, if the Board agrees, and approves only 2010 rates in this proceeding, a number of the more contentious forecasting debates are less problematic. Of considerable importance, for example, is the debate about the level of renewable generation connections Hydro One can expect in 2010 and 2011, a debate that deals with hundreds of millions of dollars of proposed spending. By approving only 2010, the Board can, as we suggest later, use a funding adder plus variance account approach, and by the time a decision on 2011 is required, the Board will be able to track the previous forecast and see whether it is as unreasonably high as some parties think.

1.2.9 It is therefore submitted that this Board should accept the economic and business planning assumptions for 2010, subject to our comments elsewhere in this final argument, but should not accept those assumptions for 2011, **and therefore should not approve rates for 2011.**

1.3 *Service Quality*

No submissions.

1.4 *Implementation Date*

1.4.1 SEC notes that on January 21, 2010 the Board issued a letter to stakeholders announcing a consultative process (EB-2009-0423) to "review the need for and the implications of a potential alignment of the rate year with the fiscal year for electricity distributors."

1.4.2 The letter notes that in a recent decision with respect to Enersource (EB-2009-0193), the Board did not approve the distributor's application to change its rate year. Instead, the Board indicated that the implications of such a change needed to be examined fully in a Board policy context and therefore that the Board would initiate a consultation in this matter in the near future. That consultation has now commenced. We supported that generic approach in the Enersource proceeding, and we continue to support it.

1.4.3 Given the consultation in process, SEC submits that the accelerated implementation sought in this application be rejected, as the Board will be dealing with the matter in a generic context. It is, in our view, inappropriate for this Board panel to establish a new policy when the Board is already considering that in another proceeding. Further, to the extent that Hydro One is a special case for effective date purposes (for example, because other utilities rely on some of their rates), the Board's handling of their request must in any case depend on what the rules will be for other distributors going forward.

1.4.4 We note that, due to the current status of the calendar, Hydro One has accepted that a January 1, 2010 implementation date is no longer possible, and has withdrawn that proposal. However, Hydro One would still like the Board to order that 2011 rates be implemented as of January 1, 2011.

1.4.5 For the reasons we have set out in section 1.2 above, we do not believe the Board should be approving 2011 distribution rates for Hydro One at this time. In the event that the Board elects to do so, in our view it is not appropriate for this panel to set the effective date at January 1^{st}. Rather, the effective date should be May 1, 2011, subject to any change in the Board's policy with respect to rate changes arising out of the current consultation in EB-2009-0423.

1.5 *Overall Increase in Revenue Requirement.*

1.5.1 Electricity rates are increasing at unprecedented levels: 25% over two years for the direct rate increase alone [Ex. J4.4]. In addition to that staggering increase, ratepayers will have to pay Hydro One's share of the socialized costs of the GEP (the cost of which may eclipse the distribution rate increase), plus HST increases, commodity cost increases, special charges, and many other amounts.

1.5.2 These increases are the result of a combination of factors:

(a) The ever increasing cost of servicing Hydro One's existing distribution system. Despite continuous investments in the system with a view of reducing costs, it appears in fact that costs only ever increase, and at an increasing rate. In fact, unlike almost all other electricity distributors in the province, Hydro One has repeatedly eschewed the Board's IRM process, which provides customers of *other* electricity distributors in the province with rate stability by ensuring rates increase at a rate of inflation less productivity. Instead, Hydro One has filed back to back cost of service rate applications seeking double digit rate increases, just two years after asking for a large increase in 2008.

(b) The impact of government policy decisions to alter the electricity grid to accommodate renewable generation and achieve other important goals;

(c) The Board's decision to increase the return on equity for electricity distributors. That decision alone represents a permanent 4.4% distribution rate increase for this and every other electricity distributor in the province.

1.5.3 These increases could not come at a worse time for Ontario's economy. Hydro One's service territory covers a big chunk of the province and therefore the effects of this application will be felt throughout the province. It will be felt in households struggling to get by as the recession has slashed their incomes. It will be felt by manufacturers barely managing to stay in business despite a high dollar, foreign competition and a weakened U.S. export market. And it will be felt by institutional customers such as schools, which will also be struggling with frozen or reduced budgets as reduced tax revenues force reductions in, or at least tougher limits on, funding levels.

1.5.4 These increases in the cost of delivered electricity raise three issues in this proceeding:

(a) To what extent, if any, should either the Board or Hydro One management impose an austerity program on Hydro One in order to keep rate increases down and thus protect ratepayers?

(b) What is the Board’s role in reviewing significant new GEGEA spending, and how should that role be integrated with the Board’s mandates to promote renewable generation and protect ratepayers with respect to the price of electricity?

(c) How, if at all, should the Board change how it communicates the rate and energy cost increases it approves, so that those increases are better understood by the public?

1.5.5 ***Austerity Measures.*** The Board sometimes has utilities appear before it seeking a revenue requirement in which austerity has already been imposed. Many local distribution companies are resolutely "local" in their thinking and their corporate culture, likely because of their recent history as arms of city government. In their day to day management decisions now they still strive to ensure their actions do not negatively impact the communities they serve, and in which they usually reside.

1.5.6 Hydro One does not have that history, and certainly does not appear to be willing or able to impose internal discipline in order to limit the negative impacts of their actions on their ratepayers. At pages 4 and 5 of the Staff Submissions, Staff provide useful examples of ways in which the Applicant has not paid sufficient (or even "any") attention to balancing their internal operating pressures against the ability to pay of their customers.

1.5.7 The most striking example of this is the admission by Mr. Struthers that he didn't read the letters of comment of some 150 or more of his customers [Tr3:91], expressing their concerns about increasing rates. How does a company serve its customers if it doesn't listen to them?

1.5.8 We expect that other intervenors will provide more detailed analyses of the Hydro One approach to rate increases and customer impacts. In our view, Hydro One cannot be relied on to impose austerity measures internally, because they have a history of failing to do so, including this year. If they were in a competitive business, they would have to listen to their customers, and they would have to control their costs, or they would lose sales and profits would dry up. In this situation, they clearly do not listen to their customers, and as we have noted earlier, often don't listen to this Board, which speaks on behalf of their customers.

1.5.9 It is very tempting, given the totality of the current circumstances, to ask the Board to impose overall austerity measures on Hydro One. If there was ever a time when such a step would be justified, this is it, and certainly in its role as proxy for the competitive market, the Board could cap rate increases in a economic downturn without there being any legitimate complaints.

1.5.10 We do not propose that, as tempting as it is. Instead, we believe that the Board can, through tough scrutiny of the components of this application, ameliorate the proposed rate increases sufficiently to avoid the use of an arbitrary overall cap. We do ask that the Board, in considering each of the components of the revenue requirement, keep the "austerity" goal in mind, and allow budgets of only necessary spending, not the additional spending that the applicant would like but can do without.

1.5.11 **GEGEA Spending.** Part of the increased spending – and overall increases in customer impacts from all sources – will come about as a result of GEGEA. Hydro One may debate how much that impact is (they believe it is a more significant driver in 2010 than perhaps it is), but clearly it is a major factor.

1.5.12 We discuss the Board's role in this change in energy policy briefly in Section 9 below. There will be parties who want the Board to put the brakes on renewable energy spending, acting as a source of "sober second thought" relating to this government policy. We disagree.

1.5.13 It will come as no surprise that SEC is in any case in strong support of GEGEA and its goals, despite the additional short and medium term costs that will arise in its implementation. We believe the Board also supports this policy. However, in our view neither of these expressions of support matters, because the policy decision underlying GEGEA is not ours to make – or the Board's – and the government, which does have that responsibility and right, has already made it.

1.5.14 The key to understanding the Board's role in GEGEA policy is acceptance that the direction has been set with clarity, and neither the Board nor the parties before it have the right to change that direction or impede progress to get there. In fact, the Board has a positive duty to do everything it can to support and drive success in achievement of the GEGEA goals.

1.5.15 Once that basic truth is accepted, it becomes clear that the Board's role is to make sure that the plans of the utilities designed to achieve GEGEA goals optimize the balance of speed and quality of implementation with economic efficiency in doing so. The Board's job, in other words, is to ensure that the ratepayers get the most bang for their buck in the GEGEA implementation process. "Faster", "better" and "cheaper" are the Board's responsibility. "Whether" is not.

1.5.16 In our view, this is not really different from many other aspects of the Board's regulatory mandate. Safety is an important concern in the construction and operation of the electricity distribution system. The Board never concludes that achieving an acceptable level of safety is "too expensive". What the Board determines is the best way to achieve that level at the lowest possible cost. Reliability is another example, one that is perhaps less binary than safety. The Board regularly assesses whether an incremental change in reliability is worth the additional cost to achieve it. There is never a question of whether reliability is a in and of itself goal that must be achieved. Of course it is. There is only the question of how to maximize reliability at a manageable cost.

1.5.17 But the Board does have right and responsibility to:

(a) Insist that the distributor prioritize its investments so as to mitigate the impact on ratepayers. That may mean reducing spending in areas not related to renewable energy investment in order to make room to spend more connecting renewables.

(b) With respect to renewable energy investments, only compensate the company for costs that it actually incurs. As stated below, some of the forecasts the company has developed assume more than the maximum possible cost.

(c) Provide transparent and thorough reporting to the public of the results of its decisions on GEGEA spending, so that the public can fully understand both the costs and the benefits of this government policy.

1.5.18 We will comment later on the size of the capital program Hydro One is proposing, and the uncertainty of much of its GEP spending. In our submission, the Board can provide substantial protection to the ratepayers by controlling the growth of Hydro One's capital spending overall, and managing the uncertainty of renewable connections in this early period of FIT. This allows the Board to protect the ratepayers while at the same time enthusiastically supporting the government's historic shift to renewable generation in Ontario.

1.5.19 ***Communications, Reporting and Transparency***. We have had an opportunity to review a draft of the extensive and thoughtful submissions of CME on the need to improve how electricity cost increases are communicated to the public. CME proposes a new, comprehensive reporting framework that would ensure, at any given point in time, that all items that cause increases in the cost of delivered electricity are reported in an integrated and transparent way.

1.5.20 We cannot say at this point that we agree with all of the details of the CME position, or even all of the arguments in support of that position. Also, in general we are probably more willing than some other ratepayer groups to accept short and medium term rate increases with a view to achieving long terms benefits for society and the economy. This is in keeping with the long term view that school boards take, while acknowledging that short and medium term rate increases are just as difficult to handle for school boards as other customers, maybe even more so (because we are largely on a fixed income).

1.5.21 But those caveats aside, we strongly agree with the basic thrust of the CME submission, that it is time for comprehensive reporting. We particularly agree with the following statements of CME (taken from the draft we saw):

(a) "The Board's price protection objective under section 1, paragraph 1 of the OEB Act cannot be achieved without the adoption of an integrated approach to total price and bill impact analysis."

(b) "A bill analysis of 30% of the total bill, while holding other elements constant, is not a "total bill" analysis. It is a "partial bill" analysis."

(c) "The Board should require the utilities to present a total price and bill impact analysis of their spending plans over the duration of the five year planning horizon that each utility uses."

(d) "There is a critical need for a transparent mechanism that provides a current estimate and prospective forecast, on a rolling five year basis, of all elements of the total price and bill received by electricity consumers."

1.5.22 This is not just about the public knowing what is going on, and what is coming in the next five years. That is important, and there is a need for more transparency in communications from the Board and the utilities to the public.

1.5.23 But in addition, and arguably more important, there is a need for the Board to have information on the real total bill impacts when it is making decisions. It is one thing to approve a $1,000 increase in a $10,000 monthly bill**.** It is quite another thing to approve an increase of $1,000, on top of other increases of $2,000, so that the consumer will have to bear $3,000 per month more than today. If the latter situation – the true situation - puts that customer out of business, it doesn't really matter that the underlying costs supporting that $1,000 increase were justified. It is still a bad result. The Board needs to know the result, with more clarity than it does now, before it makes a decision to pile more increases on top of those that are already there, or coming.

1.5.24 Thus, we are in substantial agreement with the principles CME is putting forward in this regard, and believe that the Board's current policy of reporting "total bill" impacts should be corrected so that true total bill impacts are the ones being calculated and promulgated.

1.5.25 We are not, however, ready to accept the specific methodology and proposal CME has put forward. Instead, it is our view that the Board should seek to develop a method that delivers the "transparent mechanism" sought by CME, test it internally to see how it can work, and subject it to a consultation process to get input from stakeholders from all points of view. The CME approach may be a good jumping off point for that study and analysis.

2 LOAD AND REVENUE FORECAST

2.1 *Methodology and CDM*

2.1.1 The applicant is proposing a drop in load of 4.3% from 2008 to 2010, which when adjusted for increasing numbers of customers implies a drop in volume per customer of about 5.5%. Part of the reason for this is the economic downturn, but a major factor is also CDM, of which 1,325 Gwhrs. is assumed for 2010.

2.1.2 This is one of several examples where the applicant in this case was directed by the Board in EB-2007-0681 to do something, and failed to do so. In this case, the direction was to find a more rigorous way to include CDM in the load forecast. Hydro One initially expected to file the study during this proceeding [H-1-11], but it did not do so. The result is that Hydro One now proposes to go a further two years without a properly prepared load forecast.

2.1.3 This is also an example of an area in which the outdated economic and business planning assumptions used by Hydro One have a substantial impact on the deficiency for both 2010 and 2011, and therefore the proposed rate increases.

2.1.4 In the absence of the work the Board told Hydro One to do, and in the absence of any other evidence to support any CDM number or economic downturn impact for 2010, the Board is in a difficult situation. It clearly cannot accept the unsubstantiated load forecast offered in evidence by Hydro One. On the other hand, it has no other basis on which to forecast load. Without a load forecast, there are no rates. It is a conundrum.

2.1.5 In our submission, the Board should respond to this difficult situation as follows:

(a) Require Hydro One to file, <u>before</u> its next cost of service application, a comprehensive proposal to include CDM in load forecasting (including how to include an LRAM as well). As we note later, this was already supposed to be done, so the cost of this work was already included in 2008 rates. It should not be recovered again in 2010 or any other year.

(b) Only approve 2010 rates, so that the increasing uncertainty surrounding the 2011 forecast is avoided. Hydro One can seek cost of service rates for that year, and file updated information in support of the load forecast, or rely on IRM and seek cost of service rates based on better information in a subsequent year.

(c) Increase the 2010 load forecast by the amount of the apparent overstatement of CDM in 2010, which appears to us to be at least 500 Gwhrs.

(d) To protect both the ratepayers and the utility from the weakness of the load forecast when it comes to CDM, impose a symmetrical LRAM on the applicant for the 2010 test year. If the CDM is higher, then the utility will be able to recover its revenue shortfall. If the CDM is lower, the utility will have to return excess revenues collected. Stellar success with CDM will not hurt the utility's bottom line, but on the other hand failure will not result in over-recovery from the ratepayers. The LRAM should follow a conventional structure, subject to adjustment at the time of disposition when the Board has before it the CDM/forecast study with additional information on LRAM calculation in that context.

2.1.6 With particular reference to (d) above, we agree with the submissions of GEC to the effect that, absent an LRAM, the inclusion of substantial CDM in the load forecast implicitly gives a reward to Hydro One if CDM programs – their own or those of OPA or others – fail to produce the intended results.

2.2 ***External Revenues***

No submissions.

3 OPERATIONS, MAINTENANCE AND ADMINISTRATION COSTS

3.1 *Overall OM&A Budget*

3.1.1 ***2010 SDOCC Budget – Overall Level.*** For reasons set out in greater detail below, SEC submits that the 2010 budget for Sustaining, Development, Operations and Customer Care ('SDOCC') OM&A be reduced by $18.1 million in 2010.

3.1.2 Hydro One's SDOCC OM&A is proposed to increase by 14.6% between 2008 and 2010, and 24.0% between 2006 and 2010. These are surprising increases for the parts of a utility's operations that are the most likely to be stable year to year.

3.1.3 Hydro One attributes the increases in the test years primarily to: increased vegetation management expenditures, new expenditures to inspect and test oil-filled equipment to meet requirements set out by new PCB regulations, and increases in Development expenditures related to the *Green Economy and Green Energy Act* ['GEGEA']. [see Exhibit C1-2-1, pg. 2]

3.1.4 SEC understands that there are key cost drivers placing upward pressures on Hydro One's operating expenditures. SEC submits, however, that companies in a competitive environment facing key cost drivers in certain areas would work to ensure that other areas of spending are either held constant or held to minimal year over increases. Hydro One has done none of that.

3.1.5 We looked at Hydro One's 2010 SDOCC expenditures excluding expenditures identified as the main cost drivers (vegetation management, PCB Regulations, and GEGEA-related spending). What we found is an 8.3% increase over 2009, even excluding the factors that are said to really drive up costs.

3.1.6 SEC believes that a more reasonable approach would be to hold the remaining SDOCC OM&A (excluding the three special cases) to a year over year increase, over 2009, of 2%. This results in a reduction of 2010 test year OM&A of $18.1 million.

3.1.7 SEC believes that in an era when the customers are being asked to absorb significant cost increase as a result of key cost drivers, keeping cost increases in other areas to approximately the rate of inflation is a reasonable cost containment measure.

3.1.8 Furthermore, as stated below in the discussion regarding the Green Energy Plan itself, the forecasts used to develop the planned direct expenditures for the Green Energy Plan are less than certain. Therefore, there is considerable uncertainty even in part of the key cost drivers set out above which, for the purposes of this analysis, we have maintained at their forecast level.

3.1.9 ***Specific SDOCC Areas.*** In addition, some of the forecasted spending in areas included the Adjusted SDOCC OM&A are based on exaggerated or arbitrary assumptions made on the part of Hydro One.

3.1.10 For example, spending for Trouble Calls, part of the Sustaining OM&A budget, is projected to be $65.3 million in 2010. HON claims that this is less than the 2008 actual.

3.1.11 The Trouble Call budget, however, includes an allowance for storm related costs that are not capitalized. In 2008, the company experienced unusually strong storm activity; actual storm-related expenditures were $12.7 million, compared to a forecast of $8.0 million in 2010. Net of the uncapitalized storm damage costs, the Trouble Call budget in fact goes from $56.8 million in 2008 to $57.3 million in 2010. This would seem OK, but for two key facts.

3.1.12 The forecast is based on a forecast of 49,900 trouble calls in 2010. That is 1.3% higher than the average number of trouble calls experienced between 2004 and 2009 (1.7% higher if we remove the unusually high number in 2008) [H-1-19].

3.1.13 Hydro One continues to forecast increases in the number of trouble calls despite the fact that beginning in 2006 the company began a large escalation in its vegetation management budget. In 2007 vegetation management spending jumped 30% over 2006, increased again in 2009, and by 2011 will be 62% higher than it was in 2006. [See section 3.2 below].

3.1.14 One of the primary benefits of increased vegetation management spending is to reduce tree contact and therefore the number of trouble calls and related Trouble Call spending [see, for example, C1-2-2, pg. 35]. In fact, during cross-examination Mr. Gee stated that Hydro One found that there are 60% fewer outages on feeders that had been cleared in the last three years versus those that had been cleared longer than seven years [Tr5:56, lines 20-24]. If the level of accomplishment increases in a given year or series of years, therefore, one would expect there to be a higher number of feeders that have been cleared within three years, relative to previous years. SEC submits that that should translate into fewer outages, even if the company has not gone through an entire cycle of increased vegetation management activity. Mr. Gee also agreed during cross-examination that, for a feeder that is cleared, you "would start to see marginal benefits" from the fact that the company is getting to more vegetation in a particular year. [Tr5:130-131]

3.1.15 During cross-examination, the Hydro One witnesses said that the trouble call forecast was determined using a weighted average with adjustments for known events. One of the "known events" mentioned was the emerald ash borer problem. [Tr5:131-133]. However, it appears that no adjustment was made to take into account the impact of the large increases in vegetation management accomplishment.

3.1.16 Other areas that are seeing large increases between 2008 and 2011 are:

(a) a $1.6 million (25%) increase in 'Miscellaneous Services' "as a result of increases in Health and Safety programs to support the company's strategic safety goals." [Ex. C1-2-2, pg. 26];

(b) a $3.6 million (51%) increase between 2008 and 2010 in Customer Care: Other Field Support costs due to "an increase in field collections and investigation work related to receivables management." [C1-2-5, pg. 9]. During cross-examination, Mr. Adams said that this increase was due to increased arrears situations, with the result that "the amount of activity is increasing out to the field both for special investigations that may be warranted to work with the customer to investigate problems." [Tr5:141] Despite these efforts, however, Hydro One is also projecting that bad debt expenses will continue to increase, from $15.5 million in 2008 to $17.1 million in 2010 [Ex. C1-2-5].

(c) Hydro One is requesting funding for Development OM&A: Data Collection, Engineering and Technical Studies, in the amount of $6.8 million in 2010.[C1-2-3]

(d) Hydro One is requesting an increase in funding in the amount of $3.8 million in 2011 (vs. 2008) to address equipment defects [C1-2-2, pg. 20 and J6.2], which will see the company address 25,000 defects in 2011 versus 18,500 in 2010.

3.1.17 In SEC's submission, the above examples demonstrate a number of areas where the company's requested spending is based on exaggerated assumptions and/or areas where a lower level of spending would be preferable given the size of the overall rate increase facing customers.

3.1.18 In addition to the above, SEC believes that some of the GEGEA-related cost increases are inflated. For example, Hydro One has stated that its Customer Care costs will increase by $3.3 million in 2010 (and $4.4 million in 2011) in order to service renewable generation customers. [Ex. H-10-34]. This forecast, and other OM&A items related to renewable energy development, is largely based on Hydro One's assumptions about the amount of renewable energy projects that will come on line during the test years. As is discussed in greater detail below, SEC believes these assumptions are unrealistic.

3.1.19 ***Regulatory Costs***. One other area of particular concern is regulatory costs. The Board developed a 3rd Generation IRM process of one rebasing year followed by three IRM years in part as a way of streamlining the regulatory process and reducing its cost. Hydro One appears to have decided to reject that process, and come in for cost of service for every year.

3.1.20 It is true that the 3rd Generation IRM process allows a utility to decide that it wants to come in on a cost of service basis more often than every four years. However, such a decision comes at a cost, and in our view the ratepayers should not be required to bear an additional cost solely arising out of Hydro One's rejection of a Board efficiency initiative.

3.1.21 In our submission, 2010 should be an IRM year for Hydro One. The cost of an IRM application would likely not exceed $100,000, even for a complex utility like Hydro One. By contrast, the cost of this application is likely well in excess of $1 million just in out of pocket costs, and probably twice that or more when incremental internal costs are added in.

3.1.22 We have not been able to ascertain from the evidence the full cost of this proceeding, but it would appear to us that it is at least $2 million. Subject to any further information that Hydro One points out in reply, in our submission $2 million of 2010 regulatory costs should be treated as not recoverable from ratepayers. Hydro One will spend them, but they should come out of the shareholder's part, not the ratepayers.

3.1.23 ***Conclusion.*** On SDOCC OM&A in our submission the budget should be reduced by at least $18.1 million to reflect the overall percentage envelope we believe is appropriate. That level is justified by the many examples of proposed spending that appear to be excessive, particularly in a period of austerity, some of which examples we have provided above.

3.1.24 ***Benchmarking.*** We feel it is important to bring one other metric to the Board's attention. Hydro One is proposing an OM&A cost per customer in the 2010 year of $459.50 per customer. This is more than double that of many large and complex Ontario utilities, and exceeds the current OM&A cost per customer of all but one or two Ontario LDCs. For many electricity distributors, a target of $200 to $250 per customer is that norm, and they get concerned when the level exceeds $300. Veridian, for example, whose service territory has similarities to the in-town component of the Hydro One area, has filed for 2010 rates on a cost of service basis (EB-2009-0140) with an OM&A cost per customer of $197.85 [4-2-1, p. 4 in that application].

3.1.25 In our submission, when the Board is considering the many cost increases proposed by this utility, and determining what is justified, the fact that Hydro One is consistently the highest cost electricity distributor in the province should be a material factor.

3.2 ***Vegetation Management***

3.2.1 Hydro One proposed to increase its Vegetation Management substantially in 2008 over 2006, from $89.1 million to $119.4 million. Now Hydro One proposes a further increase, to $133.2 million in 2010. This represents a four year increase of 49.5%. We have two comments on this budget.

3.2.2 ***Cycle Length.*** Hydro One is proposing to shorten the trimming cycle from eight years to seven. We note that in EB-2007-0681 Hydro One proposed to shorten the trimming cycle to eight years, using a phase in over some years. At present, Hydro One is not yet in a position to measure the benefits of that shortened cycle, and now it wants to shorten it even further.

3.2.3 In our submission, Hydro One should complete the change to the eight year cycle, then go through a period of two to four years in which it measures the impacts of that shortened cycle. If the benefits then measured prove sufficiently attractive, consideration should then be given to moving to an even shorter cycle.

3.2.4 ***Lack of Benefits.*** This leads to our second key point. One shortens the trimming cycle to obtain benefits either in increased reliability or reduced long-term costs. While there may be other less important factors, those are the primary drivers for such a move.

3.2.5 In this proceeding, Hydro One has provided no evidence that it has a reliability problem that would be solved or materially improved by a shorter trimming cycle.

3.2.6 As to cost reductions, we have already commented earlier on the lack of impact of the increased vegetation management spending on Trouble Calls. We have also not seen an increase in the expected life of assets affected by vegetation, nor the most obvious impact, a reduced unit cost of trimming itself because it is done more often.

3.2.7 In four years, from 2006 to 2010, Hydro One proposes to add almost 50% to this budget area, a total of $44 million a year increase, without any evidence that the increased effort provides benefits to the ratepayers.

3.2.8 It is submitted that the increase in the vegetation management budget should be rejected in its entirety. Hydro One should be directed to keep within the existing budget, and come back to the Board when it can demonstrate through empirical data that increased spending to date has been a good investment for ratepayers, and further increases will also be a good investment.

3.3 ***Shared Services and Other O&M***

3.3.1 In addition to the allocation between the Transmission and Distribution businesses, discussed in Section 3.4, SEC has issues with Hydro One's projected Shared Services costs. As with the examples cited above under general OM&A, there are areas where, in SEC's view, the large projected increases in spending appear to be based on generous assumptions.

3.3.2 For example, Hydro One is projecting a $4.5 million increase - 33% - in its Human

Resources spending between 2008 and 2010 [C1-2-7, pg. 2]. During cross-examination, SEC asked for a breakdown of the increase in spending. The answer came in the form of an undertaking response [Ex. J7.7]. The list of work provided in the response (for example, $2.2 million for "recruitment support related line of business staff hiring", "succession planning for HR Operations", "developing and managing training programs", and "compensation and benefits support work for new staff") appears to be a summary of the type of work the Human Resources function does generally.

3.3.3 Similarly, in the Corporate Communications & Services category, HON is projecting a $4.2 million increase (50%) between 2008 and 2010 [C1-2-7, pg. 2 and H-1-41]. Most of the increase is due to projected costs of First Nations and Metis Relations: $3.4 million in 2010 and $3.5 million in 2011. During cross-examination the Hydro One witnesses were asked several times how this forecast was determined. Was there, for example, an assumption as to the number of consultations and the cost of each? The witnesses could not provide an answer, and eventually stated that the figure was "an assumption based on the work program" and that an external consultant had provided advice on how to set up the department. [Tr7:71-74] The company, therefore, has not been able to provide a concrete basis upon which its First Nations consultations budget was determined.

3.3.4 In our view, the Board should reduce approved Shared Services costs by at least $5 million in 2010 to reflect the extent to which these cost categories are unsupported in the evidence.

3.4 ***Allocations of Shared Services***

3.4.1 SEC believes that Hydro One's Shared Services costs are further over-stated by $14.8 million due to allocation problems.

3.4.2 During cross-examination, SEC introduced an exhibit [Ex. K7.3] comparing total Shared Services Costs for 2010 from the Hydro One Transmission application [EB-2008-0272] and this application. In the transmission application, the total Shared Services costs allocated to Hydro One Distribution in 2010 were 74.5% [row 4 of Ex. K7.3]. In this application, the total charged to Distribution is 79.4%.

3.4.3 Exhibit K7.3 shows that the amount of Shared Services Cost plus Customer Care costs charged to the Distribution business is $12 million higher than would be the case if the same percentage charged to Distribution in the Transmission was used in this case.

3.4.4 During cross-examination, the Hydro One witnesses confirmed that the numbers used in exhibit K7.3 are correct [Tr7:63-64].

3.4.5 The Hydro One witnesses' position, however, was that the change resulted from an update to the Black and Veatch cost allocation study so that it is based on the most recent information [Tr7:64, lines 21-28].

3.4.6 That may be, but since we are not also updating the Transmission revenue requirement to take into account the fact that the percent charged to Transmission has now decreased, it is unfair to "update" the percentage charged to Distribution in this application. As we note in the calculation below, this results in over-recovery on a combined basis.

3.4.7 Hydro One admitted as much in cross-examination:

> "*It is true that we did an allocation study update, certainly in the case of the asset management time study which forms part of the Black & Veatch study.*
>
> *We did undertake and an update to it and we did find that there were shifting in the allocation ratios towards distribution.*
>
> *Now we have included that new information into this application. In retrospect, we realized that this may have caused some confusion and we are considering that, in future applications, where we have an overlap in years between the transmission and distribution applications, 2010 in this case, that we would hold off the implementation of any updates to allocations or time studies to only the year that is not common. In this case, 2011*." [Tr7:65, line 26-66, line 6]

3.4.8 To highlight the unfairness of the change in the methodology, consider that despite the fact that the total 2010 spending, as between the Transmission and Distribution applications, has decreased by approximately $10 million, the amount charged to Distribution in 2010 has <u>increased</u> by $4.3 million.

3.4.9 Put another way: the Transmission portion of the Shared Services costs already included in Transmission's 2010 revenue requirement equals $66.4 million. If we were to add that to the amount that Hydro One seeks to charge to Distribution for 2010 in this application, $198.4 million, we get $264.8 million. That is the total amount that Hydro One would recover in 2010 for both Transmission and Distribution combined if the current evidence is accepted. But that figure is $14.8 million more than Hydro One plans to spend in 2010.

3.4.10 In sum, SEC submits that the change in allocation of Shared Services Costs as between the Tranmission and Distribution applications results in an over-payment to Hydro One and should not be allowed. As set out in Exhibit K7.3, the difference is $12.1 million. As calculated by comparing the totals to be recovered in Transmission and Distribution to the overall budget, as we have done above, the difference is $14.8 million. SEC submits that Hydro One Distribution's Shared Services 2010 costs should be reduced by that amount.

3.5 ***Human Resources Costs***

3.5.1 ***Board Concerns.*** In the 2006 Distribution rate decision as well as in the 2007 Transmission rate decision, the Board panel expressed concern about Hydro One's level of compensation and instructed the company to do something about it.

3.5.2 In the 2007 Transmission application, the Board summarized the direction given to the company during the 2006 distribution rate proceeding, as follows:

- In future rate cases it expects Hydro One to identify what steps the company has taken or will take to reduce labour rates;

- The contrast between the compensation structure of Hydro One and some other utilities is of concern; and

- In future rate cases it expects Hydro One to demonstrate that lower compensation costs per employee have been achieved or to have concrete initiatives in place to bring compensation costs more in line with other utilities.

[EB-2006-0501, p. 29]

3.5.3 ***Benchmarking.*** In the 2009 Transmission decision, the Board again examined Hydro One's compensation levels and, with the benefit of a benchmarking study, found that they were too high.

3.5.4 That benchmarking study, prepared by Mercer and Oliver Wyman, found that Hydro One's compensation, in particular that related to PWU-affiliated positions, is above the industry average. On a weighted average basis, the difference between PWU wages and comparators was 21%. A number of positions, however, exhibited far greater disparities between comparator groups: total compensation for regional maintainers is 27-29% above the benchmark median; lines supervisors are 43% above the benchmark median.

3.5.5 During the Transmission proceeding Hydro One, as well as two of its unions who had intervened in the proceeding, PWU and SEP, made various arguments to the effect that Hydro One's labour costs were not uncompetitive and that no disallowance was necessary.

3.5.6 The arguments were that a) despite the fact that actual wage rates had not been reduced, Hydro One had made significant gains in collective bargaining that reduced overall labour costs; and b) Hydro One's wage progression since 1999 compared favourably to two other of Ontario Hydro's successor companies, Bruce Power and Ontario Power Generation.

3.5.7 In this proceeding, Hydro One has made similar arguments. Hydro One says, for example, that it "asks the Board to consider the history of gains made through collective bargaining when assessing the prudency of the collective agreements [with PWU and the Society]." [C1-3-2, pg. 12]. It then says that "a more useful comparison would be the compensation wage scales for similar PWU and Society classifications at Ontario Hydro successor companies." [ibid., pg. 13]. It then points to a table, similar to a table that was in evidence in the Transmission proceeding [J7.6], comparing various PWU pay rates with similar rates at OPG and Bruce Power.

3.5.8 As was pointed out during the cross-examination of Panel 4, all of these arguments were heard by the Board in the Transmission proceeding [see Tr7: 54-58].

3.5.9 In fact, we see from the Board's decision in the Transmission proceeding that the Board took those factors into consideration in arriving at the $4 million disallowance. For example, the Board said in its decision:

> "*In determining the appropriate disallowance, the Board has also considered that Hydro One has demonstrated effort and progress in managing the collective agreements that were established by the predecessor company. However, it is worth noting that the Board places little weight on the company's submission in its final argument that its average annual increase per employee has remained very low over its recent history*."
>
> [EB-2008-0272, Decision with Reasons, pg. 30; Exhibit K7.4 in this proceeding]

3.5.10 When asked about the apparent similarities between the arguments made in the last case and the arguments in this case, the Hydro One witness replied as follows:

> *"MR. DeVELLIS: Okay. So my question, it appears that all of these factors were already before the Board in the transmission decision, and the result of that was still a $4 million disallowance?*

> *MR. MCDONELL: No, I wouldn't totally agree with that for a couple of reasons.*
>
> *First of all, this chart we're now looking at is a broader version of what we had in the transmission case.*
>
> *And we also took the -- we took this opportunity in this filing to show more comparisons, but we also took the opportunity in our prefiled evidence to show another very important factor, and that is Bruce and OPG, and as a matter of fact the other successor companies, are very relevant comparators to Hydro One in terms of being able to recruit staff, and also be able to retain our current staff, which was not part of the argument made in the transmission case.*" [Tr7:58]

3.5.11 In SEC's submission, all that Hydro One has provided in this case that is different from the Transmission cases are a handful of additional job classifications to compare to OPG and Bruce Power. The substance of the argument, however, remains the same. In SEC's submission there has been no substantive change since the Transmission decision and the result in this case should be the same.

3.5.12 As mentioned above, the Board in the Transmission decision disallowed $4 million in OM&A to account for the fact that it viewed Hydro One's compensation to be excessive relative to other utilities. In an interrogatory, Hydro One was asked what the equivalent figure would be in this proceeding, given the Distribution business' share of total compensation as well as the projected increase in the work program for 2010. HON replied that the equivalent figure would be $9 million. [see Exhibit H-10-40(b)(iv), and Tr7:60] SEC believes that that, for the reasons set out in the Transmission decision, that amount should be disallowed from Hydro One's distribution OM&A.

3.5.13 ***Overtime.*** SEC also believes that Hydro One's overtime budget for 2010 is over-stated. Overtime costs are proposed to increase by 30% between 2008 and 2010 [C1-3-2, pg. 9], but there doesn't appear to be any reason for that increase.

3.5.14 The work program, of course, is increasing, and that is reflected by the fact that base wages increase by 55% over the same period. Hydro One also claims, however, that the overtime cost increase is due to the increase in the work program [H-1-72].

3.5.15 Yet Hydro One's own evidence demonstrates that overtime is driven by unplanned events. Therefore, increases in the work program should not lead to concomitant increases in over-time.

3.5.16 In fact, in response to an interrogatory Hydro One states that "overtime is driven by the essential nature of Hydro One's business. Factors that result in overtime include storm restoration, trouble calls, system outages and off peak time, geography and major line construction projects." [H-1-72] All but one of those items are unplanned events. Hydro One is not forecasting large increases in unplanned events.

3.5.17 During cross-examination Hydro One witnesses agreed that, while some overtime would occur even on planned work, it "would be the exception rather than the rule." [Tr7:76] The witnesses could not explain the increase in overtime other than to point to the increased work program.

3.5.18 It is useful to note that 2010 is not the first time that Hydro One has substantially increased its work program. The same occurred between 2006 and 2008. During that period, base wages increased from $368 million to $464 million, a 26% increase [C1-3-2, pg. 9]. Overtime during that same period, however, increased by just 1.9%.

3.5.19 In our submission, the 30% planned increase in overtime has not been justified by the evidence, and it should be reduced to the level of around 2% increase that seems typical of its past.

3.5.20 ***Headcounts.*** The one other area that we feel needs to be addressed is the drastically increasing headcounts at Hydro One, year after year. A good example is found in J8.4, which shows a proposal to increase "Head Office/GTA" headcount by 47.1% over the three years 2008 through 2011. This is during a period in which customer count is not likely to go up by more than 4% over the same three years. This is after a 2008 application [EB-2006-0681] in which the utility proposed a 33.5% headcount increase from 2006 to 2008.

3.5.21 There is no delicate way to put this. Government-owned monopolies become bloated with too many people, and unsustainable costs, because of a <u>failure of oversight</u>. Sometimes that oversight is through government departments, as with some Crown agencies, and sometimes that oversight is via an independent regulator, as with Ontario LDCs. If Hydro One is allowed to continually increase its staffing levels despite small increases in the customers it serves, that will not be a failure of Hydro One. That will be a failure of its regulator.

3.5.22 In our submission, it is time to put a stop to this. We all saw what happened to Ontario Hydro in the 80s, when it grew past a sustainable level, and needed more and more work to keep its people busy. We are still paying the accumulated stranded debt that failure of government oversight caused. This Board is in a position to prevent that from happening again, but the signs are there.

3.5.23 We therefore submit that this Board should deny increases in headcount that exceed the increases in customer count. This will send a clear message to Hydro One that there will be tougher scrutiny of its staffing increases. At the same time, the Board should require Hydro One to provide, in any future rate case in which it has staffing increases that are not driven by customer increases, a complete justification of those new positions, including not only a cost benefit analysis, but also a comparison between hiring in-house and contracting out.

3.6 *Depreciation Expense*

No submissions.

3.7 *Capital and Property Taxes*

No submissions.

3.8 *Income Taxes*

No submissions.

3.9 *Loss Reduction Efforts*

No submissions.

4 CAPITAL EXPENDITURES AND RATE BASE

4.1 *Rate Base Amounts*

No submissions in addition to those in section 4.2.

4.2 *Capital Expenditures Budget*

4.2.1 ***Building a Construction Company***. In 1985, observers of the Ontario electricity sector noted that Ontario Hydro had built the biggest construction company in Canada. This was generally justified by the massive generation and transmission projects either in progress or planned in this time frame. The tens of thousands of employees Ontario Hydro had at that time were needed because of those projects, many of which of course ended up costing more than they should.

4.2.2 We see signs of the same pattern emerging in the current Hydro One, and it gives us great concern. We have commented in section 3.5 above on the rapidly escalating staffing levels, far in excess of what could possibly be needed given the underlying fundamentals of the business.

4.2.3 Capital spending plans are the other side of that coin. Hydro One expects that it spent $450.5 million on capital projects in 2009, but it proposes to spend a total of $716.3 million in 2010, and $839.6 million in 2011. For the 2010 year, this is a one year increase of 59.0%, and further expansion is planned for the following year. These are only spending on the distribution side. We know that the transmission side will also have a massive capital spending plan when it files its application for rates in March.

4.2.4 It is all very well to say "GEGEA made me do it", and justify both the huge spending increase and the huge staffing increase on that basis. In our submission, this is not acceptable, and will, if unchecked, lead to a new government-owned construction company, once more looking for more and more projects for its many employees to build.

4.2.5 ***Prioritization.*** Instead of this unchecked race to increase spending, which it would appear to us will be difficult for Hydro One to digest in any case, we believe that this Board should require Hydro One to actively prioritize its projects on its existing system, and its GEGEA projects, within an overall envelope that is reasonable given its current resources. That envelope, in our submission, should be no more than $600 million, which presupposes a distribution capital expenditures budget of about $460 million. This would be a 2.1% increase over 2009 for distribution rates, but still a 33.2% increase in workplan.

4.2.6 ***Enterprise Impacts.*** Further, in our submission Hydro One should be actively discouraged from spending its increased capital dollars on new internal staff. This creates a larger and larger internal workforce that needs to be paid and kept busy.

4.2.7 Instead, Hydro One should be required to manage initial large increases in capital spending through outsourcing/contracting out of the work. Only if, after two or more years, it is clear that the increase in capital spending is permanent, should Hydro One consider adding to its full-time complement to handle the workload. In this way, the danger of increasing the ongoing size of Hydro One is controlled, and increases in its enterprise size are only allowed when there is a proven underlying change in the work to serve its responsibilities.

4.3 ***Shared Services and Other Capital***

No additional submissions.

4.4 ***Allocation of Shared Services and Other Capital***

No additional submissions.

4.5 ***Working Capital***

No additional submissions.

4.6 ***Asset Condition Assessment***

No additional submissions.

4.7 ***System Loss Expenditures***

No additional submissions.

5 CAPITAL STRUCTURE AND COST OF CAPITAL

5.1 *Capital Structure and Rate of Return on Equity*

5.1.1 The Board is aware that SEC and other ratepayer groups do not feel that the ROE established in the Board's December 11, 2009 Report on the Cost of Capital is appropriate, nor is it based on proper evidence**.** It is submitted that the onus lies on Hydro One to file evidence supporting its claimed 2010 return on equity of 9.75%, and it has failed to do so although given the opportunity. The Board's Report was not based on properly tested evidence, so it cannot be relied on for that purpose. Therefore, it is our view that there is no evidentiary basis for an increase in rates based on changing the ROE from the current level to 9.75%.

5.1.2 That having been said, we accept that this Board panel has essentially rejected that argument in its decision on the scope of the cost of capital issue. While we continue to believe that as a matter of law that our argument above is correct, there is no point in pursuing it further in this proceeding. Therefore, our submissions on return on equity are limited to two points.

5.1.3 ***Flotation Costs.*** First, it is clear that Hydro One has no flotation costs for equity. It does have such costs for debt it raises on the public markets, but it includes those flotation costs in the cost of debt already. With respect to flotation costs for equity, it is submitted that the 50 basis points allowance for flotation costs included in the Board's Cost of Capital Report is not applicable to Hydro One. It is, it is submitted, not appropriate for the Board to provide a regulated utility with recovery from ratepayers for a cost the Board knows will not be incurred.

5.1.4 ***2011 ROE***. We have separately proposed that the Board should not approve rates for 2011, since the economic and business assumptions on which they are based are insufficiently robust to be relied on. In the event that the Board agrees with us, the issue of 2011 ROE is moot.

5.1.5 However, in the event that the Board decides to approve rates for 2011, in our submission those rates should not include any change in ROE from 2010 levels. It is submitted that the applicant has not provided sufficient evidence for the Board to properly forecast the ROE that would be calculated based on the Cost of Capital Report. It is also not appropriate to leave it to an actual calculation at the time, unless all other aspects of rates for 2011 are also adjusted for updated economic and capital market assumptions. Therefore, if 2011 ROE cannot be forecast on the evidence before the Board, and it cannot be adjusted later in isolation, it must remain the same. This is, in fact, what the Board does when a utility's rates are set using IRM. The same should apply here.

5.1.6 We note that our proposal that the Board set only 2010 rates solves this well. If Hydro

One elects to use IRM in 2011, then it retains the same ROE and other components of cost of capital implicit in its existing rates. If Hydro One elects to file for cost of service for 2011, then the Board will have up to date information, and will be able to set the proper ROE, as well as the proper cost of debt and other aspects of revenue requirement.

5.2 *Debt Costs*

5.2.1 ***Long Term Debt.*** We have two problems with the forecast cost of long term debt.

5.2.2 First, we note that the long term debt issued in 2009 had lower average costs than is built into the forecast. Thus, for 2010 the cost of long term debt will be 0.044% lower than the forecast amount [J4.6]. Since this is a forecast error on which there is now better information, in our submission the cost of long term debt should simply be lowered by this amount. The result should be a revenue requirement reduction of about $1.26 million.

5.2.3 Second, we are concerned that Hydro One has not adjusted its long term debt costs for the impact of improved interest coverage and other ratios arising out of the Cost of Capital Report. There is no evidence before the Board on this point, but it is Finance 101 that higher levels of return on equity produce lower interest costs due to improved ratios. This can be gleaned by a simple reading of any DBRS report.

5.2.4 On this second point, we are concerned that the lack of evidence may result in Hydro One over-recovering interest on long term debt. A simple and expedient solution would be to reduce the weighted average cost of long term debt by a factor estimating this impact, perhaps ten to fifteen basis points. That would be arbitrary, but the $3 to $5 million reduction in long term debt costs is not likely to be far wrong.

5.2.5 The more precise alternative would be to create an asymmetrical variance account for the weighted average interest rate on long term debt. If the weighted average interest rate on Hydro One debt (new and embedded) turns out to be less in 2010 than the currently forecast 5.673%, the difference in interest cost would be credited to the variance account for later disposition to the ratepayers. We do not prefer this approach, because getting it right is too complicated given the small amounts involved, but it is the more correct solution if the arbitrary adjustment we have proposed is not accepted by the Board.

5.2.6 ***Short Term Debt.*** Hydro One notes [J10.7] that its actual short term debt rate in 2009 was 0.96% in a period in which the average prime rate was about 2.32%. In 2010, Hydro One is expecting [see J4.6] a average short term debt rate of 1.19%, in a period in which the average prime rate was forecast to be 2.59%. Thus, the actual cost of short term debt was, and in fact still is, expected to increase roughly in line with the prime rate.

5.2.7 But Hydro One has instead argued that updating its short term debt rate would require using the Board's Cost of Capital Report, which results in a 1.934%. This is one of the reasons it proposes to update return on equity, but not the cost of debt (short or long term debt).

5.2.8 With respect, we do not read the Board's Cost of Capital Report as requiring Board panels knowingly to ignore the evidence before them, and in the face of contrary evidence to order recovery from ratepayers of an amount for interest on short term debt that exceeds the forecast amount.

5.2.9 Instead, it is our submission that if the utility has more recent information that materially alters a fact or forecast before the Board in this proceeding, it is obligated to bring it forward. In the case of short term debt, it does not. The short term debt rate it currently expects to incur is 1.19%, the amount that is built into the proposed rates. In this context, the Cost of Capital Report is simply irrelevant.

6 DEFERRAL AND VARIANCE ACCOUNTS

6.1 *Disposition and Continuance of Existing Deferral and Variance Accounts*

No submissions.

6.2 *New Deferral and Variance Accounts*

6.2.1 ***Lost Revenue Adjustment Mechanism.*** GEC has been trying for some years to achieve an LRAM for Hydro One. In the last proceeding, EB-2007-0681, Hydro One was ordered to study how to do appropriate measurement so that an LRAM can be implemented easily. It failed to file that study.

6.2.2 However, in our view the need for an LRAM has been established, and the much greater CDM forecasts now being proposed make its implementation more urgent, not to replace utility revenue, but to the protect the ratepayers from over-recovery of CDM revenue losses in rates.

6.2.3 ***Pension Costs.*** This account is said to be an extension of an account already approved in EB-2007-0681[H-7-99]. However, under cross-examination from SEC [Tr9:65-7], Mr. Fraser from Hydro One admitted that there is in fact one major change to this account. There was a revaluation of the pension assets as of December 31, 2009, and the impact of that new valuation is to be included in the account in 2010. The witness agreed that the amount involved could be "significant", even a "massive change" [Tr9:66].

6.2.4 Given the size of the stock market collapse in 2008 and 2009, and other impacts on asset values, we agree that this new inclusion in the account could be a big one. As the witness pointed out, while technically it could have been included in the account as previously described, it would not have been because there was no valuation. Now that there is, it results in a pretty big change.

6.2.5 We have two submissions on this. First, this big a change in how a variance account will in fact work (even if not a technical change), should be disclosed to the Board in the prefiled evidence and highlighted for its materiality. The last thing the Board wants is that an intervenor has to dig this out at the very end of the proceeding, in cross-examination in an oral hearing.

6.2.6 Second, we do not agree that this change to the account is appropriate. We could be talking about a very sizeable sum, and this Board has no idea what it will be made up of, or how big it will be. In our view, it is not appropriate to order that it be dumped into a variance account without further information.

6.2.7 In that regard, we note that this is precisely the kind of situation in which the new IFRS rules are likely to require different treatment of the change in value relative to Canadian GAAP.

6.2.8 Therefore, we propose that rather than approve this account now, the Board advise Hydro One that, when it has the new valuation of its pension fund, it should make an application to the Board detailing the potential impacts, and how it proposes to deal with them from a regulatory point of view. This should include things like IFRS impacts, options from a pension funding point of view, etc. The Board can then, with proper information before it, make reasoned decisions about how to address what could be a very substantial amount. This could include charging the new shortfall to a variance account, but it could also include immediate recovery methods, ordering a new valuation for December 2010, or any of a broad number of other options.

6.2.9 ***OEB Costs.*** SEC agrees with Board Staff's submission that two of the accounts proposed by Hydro One should be rejected; namely, the OEB Cost Differential Account, and the Impact for Changes in IFRS Account. Both accounts have been rejected in previous proceedings and Hydro One has offered no reason why this Board panel should find differently.

6.2.10 With respect to the OEB Cost Differential Account, SEC submits, frankly, that Hydro One has been disingenuous in its presentation of this account. In the pre-filed evidence, Hydro One proposes that this account track "the difference between the annual OEB Cost Assessments, intervenor cost awards, and costs associated with the OEB-initiated studies and the amount for these expenditures approved by the OEB." [F1-1-2, pg. 1] In an interrogatory, Hydro One was directed to the Board's decision in EB-2007-0681, which was Hydro One's previous distribution rate case prior to this one, in which the Board found that it did "not consider it reasonable in this case to exempt Hydro One from the Board's current policy not to authorize an OEB cost variance account to distributors." [H-1-118(a)] Hydro One was to confirm whether the account it is seeking in this proceeding is similar in nature to the account it was seeking in EB-2007-0681. Hydro One replied that it is. [see also Tr9:62]

6.2.11 But then in a follow-up question, Hydro One was asked, if it is the same account, "what is the regulatory precedent for the collection of <u>each of the identified costs</u> proposed to be included in this deferral account." (emphasis added). Hydro One replied, somewhat cryptically:

> "*Subsequent to the above noted Distribution decision, the Board Decision in EB-2008-0272 Section 8.2 Disposition and Continuation of Existing Accounts, the Board finding on page 56*." [H-1-118(b)]

6.2.12 That section of EB-2008-0272, however, refers to the *disposition* of an account that already existed - Account 1508, OEB Cost Assessment Differential - and which only refers to Cost Assessments. In cross-examination, the Hydro One witnesses admitted that the EB-2008-0272 decision only refers to one element of the three elements that Hydro One proposed to be included in the current proposed account [Tr9:61-62].

6.2.13 The response to H-1-118(b), however, clearly was meant to leave the impression that the decision in EB-2008-0272 is a precedent for all of the elements proposed to be tracked by the current proposed account. In SEC's submission, it is unfortunate that these types of distortions have to be uncovered in cross-examination.

6.2.14 ***IFRS Impact Account.*** SEC also agrees with Board Staff that Hydro One's proposed IFRS Account is similar to the one considered and rejected by the Board in EB-2008-0408 and that therefore the account should not be approved in this proceeding.

6.2.15 In passing, we note an irony here. Hydro One argues that it should have the IFRS Impact Account, even though a Board policy proceeding rejected that type of account. Hydro One also wants other Board policies not to apply to them, such as the 3rd Generation IRM, or LRAM, etc. We could list a dozen. On the other hand, when a favourable policy comes along, like the Board's Cost of Capital Report, Hydro One is quick to seek the benefit of the policy, and quick to reject any idea that it must show that the policy is appropriate. The benefit of that additional ROE, provided by a policy, appears to be seen as a matter of entitlement. Other policies, those that are less convenient for Hydro One, appear to be seen as more optional.

6.2.16 Hydro One, in considering the updating of their evidence, were vociferous in their opposition to "cherry-picking". The passing irony is that, in this application, Hydro One seems quite willing to engage in cherry-picking: of Board policies, Board directions, and anything else that they don't agree with.

7 COST ALLOCATION AND RATE DESIGN

7.1 *Cost Allocation*

7.1.1 ***Density Study.*** We had originally planned a lengthy analysis here of the evidence of Mr. Todd and Dr. Woo relating to density or urban/rural rates, and the cross-examinations of both witnesses. But what transpired was not fully expected. The witnesses appeared to agree that there is an existing lack of data, and the current rates do not have a proper empirical foundation. (Everyone understands that the existing density based rate class has no empirical basis: see Tr9:53.) The two witnesses also appeared to agree that exploring a more prosaic urban/rural distinction rather than strictly density-based rates was both more common and worth further review. With one exception, there was little disagreement between them

7.1.2 What they appear to differ on most clearly is whether investigation of the underlying data, using direct information as proposed by Mr. Todd (on which Dr. Woo agreed), or using proxy information as proposed by Dr. Woo, would be of assistance in determining the optimum rate class divisions and structure. Dr. Woo's approach is to gather the data (which he says is not a costly exercise), and let the data help reveal the possible rate classifications that most closely follow cost causality. Mr. Todd's explicitly rejects the ability of data gathering to assist in developing rate classifications, and says that in any case it is too costly.

7.1.3 With respect, Mr. Todd is simply wrong here. This Board does not establish rate classes based on zero information, and it doesn't expect its regulated entities to do so either. Rate classes must have an empirical basis. There may be a judgment call as to the level of empiricism that can or should be achieved for a given cost, but simply rejecting additional information because rate classes are not informed by data implies that rate classes have no basis whatsoever – they are simply arbitrary. We do not believe that to be the case.

7.1.4 ***The Board's Direction.*** This is another example of a clear direction from this Board that was not followed by Hydro One. Told in clear terms in EB-2007-0681 to do a study of the relationship between density and cost of service, Hydro One did not do so, and admits that they did not. What they did instead is report to stakeholders, many of whom opposed the study in the first place, that they did not want to do it, and they were going to ask the Board for "further guidance". When "a majority" of the stakeholders – i.e. excluding SEC and CME, who had taken the lead in seeking this further information – continued to agree that the study is not needed, Hydro One treated this as justification for its non-compliance with the Board's directive.

7.1.5 We have commented earlier on a regulated entity simply ignoring a Board direction, and we reiterate that the regulatory process cannot function properly if regulated entities do not accept the Board's authority.

7.1.6 But in our view this goes beyond the matter of respecting the Board's directions. In EB-2007-0681 Hydro One proposed harmonization of rates between its legacy and acquired customers. The acquired customers, which include a substantial proportion of the schools in the Hydro One franchise area, reside or operate mainly in small towns throughout southern Ontario. They were previously served by local MEUs, but their municipal owners sold then to Hydro One. Their rates reflected the cost of typical small town utilities, like many that still exist in the province today (Veridian, for example, is an accumulation of such utilities).

7.1.7 In the proposed harmonization, rates for those in the acquired towns were expected to jump up rapidly, so much so that even imposing a 10% total bill limit, it was expected to take four years for many of them to be fully harmonized [Tr9:45]. In fact, with underlying increases in costs, it now looks like it will take five years or more for them to be fully harmonized [Tr9:45-6].

7.1.8 By way of example, that would mean a school with an overall electricity bill of, say, $50,000 per year in 2007 may, by 2012, have a bill of $75,000. Ah, but that's wrong. That is only the impact of the distribution rate changes. The changes from the many other pressures on the cost of delivered electricity (i.e. the other 70% of the bill) are also substantial. Even if those only average 5% of total bill per year, the result is that this hypothetical school will have seen its total cost of delivered electricity double in the five years from 2007 to 2012.

7.1.9 If that hypothetical school was undercontributing in the first place, so be it. The problem is that, on the evidence before this Board, it cannot – and Hydro One has admitted this – conclude that the school was undercontributing in 2007. It is being forced into large bill increases because it has arbitrarily been assigned to a rate class that arguably does not reflect the costs to serve it.

7.1.10 We say "arguably" because in fact no-one knows. Through extensive cross-examination and debate in EB-2007-0681, it became clear that Hydro One does not have any information on the differences in cost to serve those in the towns, and those in the rural areas. The Board (in our minds holding its figurative nose) allowed Hydro One to proceed with the harmonization. However, it also ordered the production of a study so that at the next cost of service case the Board panel would have hard evidence of cost differentials between "town" and "country" customers.

7.1.11 Thus, this is not just about compliance with Board directions. That by itself is an important consideration. But this is also about large rate increases that are not justified by evidence that those increases are reflective of cost to serve.

7.1.12 In our submission, the Board in EB-2007-0681 realized that harmonization can only be delayed so long, and it had been delayed once already for Hydro One. On the other hand, the Board recognized the flimsy evidentiary record before it, and so ordered that the evidence be supplemented as quickly as possible.

7.1.13 Meanwhile, in 2008 and 2009 those residents of the acquired towns, including schools, small businesses, and others, have been forced to bear 10% total bill increases for two years. Had the applicant done as directed, those large increases could be revisited in this proceeding, with hard evidence filling in the many gaps in the previous record.

7.1.14 Instead, Hydro One has not filed the new evidence, thus apparently dooming the town residents to 10% total bill increases for at least two, and maybe three more years.

7.1.15 Further, Hydro One now argues that the density and cost allocation study should not be done until the harmonization plan is complete. That is, whether it is right or wrong, in the vernacular "let's finish doing the damage before we think about repairing it".

7.1.16 Our argument here is about simple fairness. This is not caviling about whether a distribution rate increase should be 3.0% or 3.5%. This is about customers suffering the maximum allowable bill increase for four or five years in a row, not because they are undercontributing, but because they were assigned to a new rate class without any supporting evidence.

7.1.17 ***Recommendations on Density and Urban/Rural Rates***. In this situation, it is our submission that the fair result is the following:

(a) Hydro One should be directed to complete a proper study of the relationship between density and cost of service as soon as possible. While the Board is reluctant to order consultation with intervenors (such as SEC and CME) in such a study, it would probably be useful to provide a gentle reminder that a study done co-operatively is more likely to cover all of the bases, and achieve greater regulatory efficiency, than a study done in an adversarial manner by a utility still seeking to justify its original position. This is particularly useful given that the SEC expert witness, Dr. Woo, clearly has the expertise and experience to add value to any work Hydro One is doing in this area (and has worked with Ontario Hydro before).

(b) Until Hydro One tables the study it was required to table, and the Board has a chance to review it and determine what changes in rates, if any, are required, the harmonization process should stop. Those ratepayers who are enduring 10% total bill increases year after year, from distribution rate increases alone, and probably 20% per year in total, should get a reprieve from the harmonization increases until the Board has had an opportunity to review the evidence it should have had in this proceeding. Not only is this fair to those ratepayers (especially if the evidence would have given them relief had it been before the Board in this proceeding), but

it will serve as a clear message to Hydro One that it cannot avoid a direction of the Board through delay, until the point becomes moot.

(c) The cost of the study should not be added to OM&A for 2010. The cost of the study was, by necessary implication, included in the revenue requirement for 2008, when the study should have been done. Hydro One should not be able to recover that amount again by having it included in this year's rates.

7.1.18 It is submitted that the ratepayers in the acquired towns are entitled to the protection of this Board**.** Where, as here, a utility fails to treat them fairly, despite being directed to do so by this Board, this Board should take steps such as those we have recommended to rectify the situation.

7.1.19 ***Hopper Foundry.*** SEC is on record as supporting appropriate relief for Hopper Foundry, who are in the life and death struggle they describe in their evidence primarily because they structured their business operations around a government and Ontario Hydro goal (reducing on-peak demand), and now are finding the rug pulled out from under them. We have not changed our view.

7.1.20 In our view, sometimes simple is best. Here, the simple solution is to grandfather Hopper Foundry's special rate until they no longer need it, or until the Board's cost allocation and rate design initiatives come to their logical conclusion, and the impact on customers such as Hopper Foundry has been considered in those initiatives.

7.1.21 While we believe that some of the other solutions have potential, they remain temporary fixes, and they still remove the basic electricity cost assumption that the government and Ontario Hydro induced Hopper Foundry to make, now to their detriment.

7.1.22 We therefore urge the Board to grandfather the existing rate structure of Hopper Foundry.

7.1.23 ***Other Areas.*** Aside from these specific areas, we have no submissions on cost allocation.

7.2 ***Revenue to Cost Ratios***

No submissions.

7.3 ***Fixed/Variable Splits***

No submissions.

7.4 ***Rate Impact Mitigation Plan and Customer Bill Impacts***

See our submissions under Issue 1.5 above.

7.5 ***Retail Transmission Service Rates***

No submissions.

7.6 ***Proposed Rate Rider #6***

No submissions.

7.7 ***Distribution Loss Factors***

No submissions.

8 SMART METERS

8.1 ***All Issues 8.1 through 8.4***

No submissions.

9 GREEN ENERGY PLAN

9.1 *Compliance with Guidelines and Objectives*

No submissions.

9.2 *GEP in Context of Capital and OM&A Budgets*

9.2.1 The Hydro One witnesses agreed that the total distribution capital expenditures in 2010 and 2011, including expenditures for which the company expects to receive funding from external sources, are $716.3 million in 2010 and $839.6 million in 2011. [Tr1:35]

9.2.2 These figures represent a nearly 100% increase in Distribution capital spending from 2008 to 2011.

9.2.3 In SEC's submission, there is a considerable degree of uncertainty regarding the amount and location of capital spending relating to the Green Energy Plan. In the pre-filed evidence, Hydro One itself states that "forecasting the actual number and type of projects is challenging". The forecast number of projects, and their location, is based on Hydro One's experience under the RESOP program. That program, of course, has now been supplanted by the Feed-in Tariff ("FIT") program. Again Hydro One admits that the experience under the FIT program may be different: "It is recognized that the number and type of generation connection applications may change significantly once the GEGEA and all related regulations and programs, such as the FIT program, are implemented." [D1-3-3, pg. 11].

9.2.4 Furthermore, in cross-examination, the Hydro One witnesses emphasized the differences between the RESOP program and the FIT program. Mr. Graham, for example, stated that using the "RESOP experience in term so going forward as analogous to FIT is not appropriate." [Tr1:108].

9.2.5 The Green Energy Plan is under-pinned by an assumption that 3,500MW of renewable energy will be on-line by 2011 and an additional 3,500MW by 2014, for a total of 7,000MW. [A-14-2, pg. 2; H-13-14]. During cross-examination, however, Hydro One's witnesses indicated that 1,280MW is expected by the end of 2010. [Tr1:50]. Even that would appear to us to be very high.

9.2.6 It seems highly unlikely that the 3,500 MW will be installed by the end of 2011. In response to an undertaking, Hydro One provided information from the OPA regarding uptake of the FIT program. That information shows that the applications submitted during the initial launch period total 2,369 MW by the end of 2015, with applications totaling 1,634MW projecting to be in-service by the end of 2011 [Ex. J1.6].

9.2.7 The figures do not include capacity from outstanding RESOP applications. Hydro One claims, in a preamble to the response to undertaking J1.6, that the total from outstanding RESOP projects is 527MW. In arriving at that figure, however, Hydro One assumed that any project that has not officially rescinded its Connection Impact Assessment will be proceeding under RESOP and has not re-applied under FIT. In SEC's submission, given that the FIT program was designed specifically to provide greater incentives to generators, that seems highly unlikely.

9.2.8 In any event, even if the RESOP and FIT programs are added together, we still only get 2,161 MW of capacity by the end of 2011 [1,634MW of FIT projects plus 527MW of RESOP projects- see Ex. J1.6].

9.2.9 It should be noted, however, that the figures provided by the OPA regarding the FIT applications are the best case scenario if every application is accepted and every application is in-service by the date the applicant specifies in the application. We know from Hydro One's experience under RESOP that only a fraction of the Connection Impact Assessments requested eventually result in in-service projects.

9.2.10 SEC accepts that the results will be better under FIT given the more stringent security requirements, but nonetheless SEC submits that allowance should be made for the fact that a great many of the applications received will not be completed. In the first place, the applicants may not meet the OPA's Economic Connection Test. In the second place, some of the projects may not be able to obtain the financing they need to be completed.

9.2.11 In support of its position that almost all generators that apply for a Connection Impact Assessment under the FIT program will proceed to connection, Hydro One cites the fact that the FIT program requires applicants to provide "significant financial security deposits". [H-10-14]

9.2.12 Those requirements, however, should be placed on context of the total cost of development. The initial Application Security that applicants must submit, for example, is between $5,000 and $10,000/MW ("community" and Aboriginal projects qualify for a lower Application Security requirement). That compares to an approximate total development cost of $1.5 million/MW, and so for most projects will represent less than seven-tenths of a percent of project cost.

9.2.13 Finally, if the projects have not done so already, they will then have to obtain a Renewable Energy Approval from the Ministry of the Environment.

9.2.14 By contrast, Hydro One in its Plan has assumed not only the maximum, and more, number of MW's in-service, but has also assumed that it will spend the maximum, and more, on connecting each MW.

9.2.15 For example: Hydro One states that, consistent with the Distribution System Code requirements, it intends to cover up to $90,000/MW in Expansion Costs for generator connections [H-2-2-]. Yet Hydro One's forecast for Expansion projects is $695 million, or $99,285 per MW. Hydro One explained in cross-examination that the reason is that it is planning on spending more than $90,000 per MW for seven of its stations [Tr2:53-54]. Nonetheless, this example shows that Hydro One's forecast is based on spending the maximum amount, and more, for each connection.

9.2.16 So not only are the number of connections overly optimistic, Hydro One is further protecting itself by forecasting that it will spend the maximum possible amount, and more, for each connection.

9.2.17 During cross-examination, Mr. Graham, when asked to explain the reason for Hydro One's objection to a deferral account, said that the plan involves a great deal of expenditure and the company has to have assurance of recovery of the costs recovery so that it can provide assurances to the capital markets that it will have revenues to cover the costs. [Tr1:53] That is a fair point. However, what SEC is suggesting is not that Hydro One not receive funding for the projects, but rather, that Hydro One only receive funding for projects that are actually completed in the test years.

9.2.18 Given the questions raised above regarding the accuracy of Hydro One's forecasts, SEC believes it is necessary to have a variance account in order to protect ratepayers.

9.3 ***Direct Benefits***

9.3.1 The Board has asked parties to provide submissions on how the direct benefits issue should be dealt with by Hydro One, given that it is already starting to spend on renewable connection activities.

9.3.2 In our view, the Board is in the process of developing a policy for determining direct benefits. When the Board makes a decision on that policy, it should be applied to Hydro One in the same manner as all other utilities. Until then, Hydro One should use the existing approved deferral accounts for its spending, with the understanding that it will be able to apply for clearance soon after the approval of the Board’s direct benefits policy if the deferral account balances get too great.

9.4 ***Expenditures Beyond the Test Year***

9.4.1 We agree with Staff that this issue is no longer engaged for years beyond 2011.

9.4.2 For 2011, we believe that the applicant has not provided a plan that is sufficiently detailed and backed by evidence to allow for any approvals. Once the Board has further developed its policies on Green Energy Plans (for example, EB-2009-0397 and

EB-2009-0349, among others), Hydro One will be in a better position to file a 2011 plan that meets the Board's requirements.

9.5 ***Approval Criteria and Board's Role***

9.5.1 We have discussed earlier in these submissions our view of what the Board should be looking for in considering Green Energy Plans. In short, we believe that the Board should be asking whether the GEP before it is the most cost-effective way of maximizing the delivery of GEGEA goals for this distributor.

9.5.2 This likely involves a number of obvious questions: Would spending more produce incrementally better delivery of those goals? Is it possible to achieve the same level of success with more efficient spending? Are the targets in the plan realistic, and is there a mechanism to ensure that the ratepayers do not bear costs that are not ultimately incurred? Etc.

9.5.3 The reason these questions look familiar is that the Board regularly asks questions of this type in assessing whether spending to meet other goals has been optimized. Earlier in these submissions there is a discussion about the proposed increases in vegetation management spending. Hydro One is proposing sizeable increases in this category. This Board has to review those increases, and ask whether the benefits of the increased work outweigh the cost of doing it.

9.5.4 While we recognize that this kind of optimization exercise is not a trivial task, we also point out that it is precisely what the Board does in many areas. In this case, it is not in our view useful to reinvent the wheel. The Legislature assigned certain GEGEA responsibilities to the Board because those are exactly the things for which the Board has developed a specialized ability. The Board should accept that its role in Green Energy Plans is what it already does best in other aspects of energy regulation.

10 OTHER MATTERS

10.1 *Costs*

10.1.1 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. We note in particular the extensive co-operation between intervenors to minimize duplication and maximize our assistance to the Board.

All of which is respectfully submitted.

Jay Shepherd and John De Vellis
Counsel for the School Energy Coalition