Jay Shepherd
Professional Corporation
2300 Yonge Street,
Suite 806
Toronto, Ontario M4P 1E4

BY RESS and EMAIL

October 8, 2010
Our File No. 20090278

Ontario Energy Board
2300 Yonge Street
27th Floor
Toronto, Ontario
M4P 1E4

Attn: Kirsten Walli, Board Secretary

Dear Ms. Walli:

Re: EB-2009-0278 – Algoma Power 2010/11 Rates

We are counsel for the School Energy Coalition. Pursuant to Procedural Order #3, these are SEC's submissions with respect to the IFRS and Extraordinary Events issues.

IFRS Deferral Account

1. The Applicant is seeking a deferral account to reflect changes in the rules or interpretation of IFRS between today and future years. They are concerned that there is still considerable uncertainty, and there may be changes in the accounting rules that they cannot presently predict.

2. Board Staff filed a very helpful argument on October 7th, correctly pointing out that while the Applicant refers to this as a variance account, it is actually a deferral account. A variance account would arise if they were filing on the basis of IFRS, and there were changes to IFRS. That is not the case here.

3. In our submission, it is this difference that is central to the issue. A variance account needs a baseline. The Board considered, in EB-2008-0408, a proposal to allow a variance account to reflect differences in accounting treatment between CGAAP and IFRS, and rejected that proposal. Thus, if the Applicant asked for a variance account between CGAAP and IFRS, the Board could be expected to continue to reject it. Instead, it is cast as a deferral account related to new "costs" (accounting entries newly treated as current costs) associated with

Tel: (416) 483-3300 Cell: (416) 804-2767 Fax: (416) 483-3305
jay.shepherd@canadianenergylawyers.com
www.canadianenergylawyers.com

IFRS. Casting it as a deferral account does not change what it is, the very same variance account that the Board rejected already.

4. The Applicant, had they filed their Application on an IFRS basis, could then have sought a variance account to record revenue requirement impacts of changes to the IFRS rules. That is feasible, because the Board would have a baseline to start with, and only IFRS variability would be recorded in the account. Whether or not such an account would be appropriate is a matter than could be debated, but what is clear is that this issue does not arise in this case. The Applicant did not file on the basis of IFRS.

5. The Applicant refers to the variance account allowed to Hydro One Networks in EB-2009-0096. Hydro One also filed on the basis of CGAAP, but appeared to take the position that under the current IFRS, it was essentially the same as CGAAP. On that basis, the Board accepted the proposal to approve a variance account, which on the record in that proceeding appears to be an account recording variances within IFRS, not variances between IFRS and CGAAP.

6. We are a little concerned that the Hydro One variance account, which appears to have IFRS as the baseline, may not actually be doing that. The reason is that Hydro One did not argue that IFRS and CGAAP created similar accounting results. Rather, they appear to have argued that IFRS and CGAAP created similar "reported cash flows" [see page 59 of the EB-2009-0096 Decision]. Our understanding is that accounting treatment has no impact on reported cash flows anyway, so this may be nothing more than a tautology.

7. If it is not, and what Hydro One was intending to say in that proceeding is that their rates would be the same, because the puts and takes in IFRS would balance out, the Applicant here still has a problem. It has led no evidence that CGAAP and IFRS produce the same revenue requirement. In fact, the clearest indication of the substantial difference between the two accounting systems is found in the application for 2011 rates of Hydro One Brampton (EB-2010-0132), where that difference is shown to be potentially substantial.

8. Therefore, even if the Board considers the EB-2009-0096 to be an appropriate precedent for other distributors, Algoma has not provided evidence on an IFRS baseline that would be necessary to record variances in the IFRS rules and interpretations. Without that baseline, there cannot be a variance from it.

9. For the above reasons, in our submission the account relating to IFRS should not be approved.

Extraordinary Event Costs Account 1572

10. The Applicant is seeking recovery of $395,695 [Tr.1:32] plus interest for costs associated with an "extraordinary event", described as the separation of the distribution business from the generation business as required by section 71 of the Act. The Applicant has made a point of saying that these are extraordinary event costs, not transition costs [Tr.1:20], but that if they are characterized as transition costs, they should be recoverable on that basis as

well [Tr.1:21]. The costs have been recorded in Account 1572 pending the outcome of this proceeding.

11. In our submission, these costs are not recoverable from ratepayers on the first basis. We believe the cause of the costs does not qualify as an extraordinary event, but rather as a transition cost. On that basis, most of the costs are not recoverable under the Board's normal rules.

12. On the first point, the "extraordinary event" proposed by the Applicant is the requirement to separate their distribution business from their generation business under the Act. In our submission, this kind of "event" does not come within the category of event for which the "extraordinary event" account was created.

13. Extraordinary events are intended to reflect unexpected things that happen to the utility that result in the expenditure of additional costs. An ice storm grips their franchise area. A tornado touches down at one of their substations. A street riot results in substantial damage to their system. In the most extreme edge of the concept, some part of their system experiences a common cause failure (for example, the Toronto contact voltage situation).

14. While these are different types of occurrences, the one thing they have in common is that they are unexpected, and management cannot be expected to foresee the costs and build them into the budget.

15. In this case, the Applicant and its predecessor have known for some years that distribution would have to be separated from generation, and in no way was it unexpected. They were in a situation where the requirement to operate their regulated activities separately from their unregulated activities, a requirement shared with other Ontario utilities, was deferred for a finite period of time.

16. In fact, it appears that they were already taking the appropriate steps well before this "event" in 2009. For example, the operation of the generation business was entirely separate from the operation of the distribution business by May 2002 [Tr.1:47], and it was only separation of legal ownership of the generation assets from the distribution assets that was still required to be done in 2009.

17. In our view, the appropriate characterization of this is as a transition cost. In the same way that municipally owned distributors had to separate their operations from the municipality into a new corporation, so too the Applicant and its predecessor had to separate their distribution operations from their generation business, and put distribution into its own separate corporation. The tasks involved in doing so were a subset of the tasks involved in the transition of the munis. There were incorporation and legal transfers, and many other things like that. On the other hand, because the distribution business was running as a business already, the Applicant did not have to develop a new billing system, or any of that category of transition costs.

18. Once it is clear that these are in their essence transition costs (whatever they are actually called), the Board's Accounting Procedures Handbook makes clear what should be

recoverable, and what is not. The Board's commentary for Article 480 in the Handbook makes clear the categories of costs that can be claimed [p. 5], and those that cannot be claimed [p. 6].

19. In our submission, only the categories of "IMO/IESO requirements" and "Regulatory Costs" are applicable to make any costs recoverable. In both cases, there were registration and license fees included in the $3,665 total [SEC #31]. The Board does not know how much that was, because there were other fees also included in that total, and the breakdown is not know. However, the amount is small, so in our view the whole of the fees component of the claim should be allowed in full.

20. The same is not true of the legal ($269,200 – Tr.1:35), consulting ($66,390 – SEC #31), and internal ($56,400 – SEC #31) costs. Some of those costs are not qualifying transition costs, and some of them are not incremental to the normal budget of the utility.

21. In the case of legal, the evidence is that some portion of that amount was for the incorporation of the new distribution company, and the transfer of the assets from the predecessor to that company. The witness Mr. Lavoie agreed that there was a "big pile" [Tr.1:38] of legal documents, but then estimated that of the $269,200 legal bill about $40,000 was for the asset transfer activities [Tr.1:39]. Given that he admitted that there was no breakdown in the legal bill, and he had no access to the lawyers dockets, and he had no direct knowledge of what the asset transfers would cost, in our submission that estimate is unpersuasive. It strains credulity to think that a Toronto law firm acting for the Applicant would effect transfers of the complexity and volume required for a transaction of this magnitude, including all related opinions, etc., would bill only $40,000 for that work.

22. But the Board is faced with a dilemma. The Applicant has not provided evidence to support the qualifying component of the legal costs, and in fact refused to provide related evidence (the transfer documents) when asked to do so [SEC #31]. In our submission the Applicant's failure to file supporting evidence cannot be the basis for allowing a claim that clearly includes ineligible components.

23. On the legal, we therefore submit that at least half of it should be disallowed as being related to non-qualifying activities.

24. That leaves $122,830 of consulting and internal costs associated with "separation of engineering records" [SEC #31].

25. It turns out that the bulk of the "engineering records" have nothing to do with engineering at all, but are title documents associated with easements, etc., i.e. legal records [Tr.1:36]. It also turns out that this separation, part of the separation of the distribution and generation businesses, had nothing to do with generation. These records were all either transmission or distribution records [Tr. 1:34]. Further, it turns out that only $14,000 of the consulting costs had anything to do with the records [Tr. 1:36 – most of the rest was a surveyor firm for conveyancing to complete the asset transfers], and of the internal costs only some unspecified amount of overtime and backfill – on which the Applicant has provided no evidence – was incremental. The rest was not [Tr. 1:45].

26. Based on the facts in evidence, it is our submission that an insufficient foundation has been laid for the recovery of this category of costs. It looks like much of it is not incremental anyway, the main thrust had nothing to do with separating the distribution and generation businesses, and in any case the separation of records looks like it was entirely about supporting the asset transfers to the Applicant.

27. In passing, we note that the statement in SEC #31 "As set out in the response to (c) below, the costs being claimed pertain to business reengineering, and would therefore fall into the second category of costs" is not supported by any evidence. When asked about this [Tr.1:40], Mr. King first tried to say that this did not refer to what the Applicant did, but what other utilities did, but when faced with the actual wording [Tr.1:41], withdrew that comment and did not offer any support for the "business reengineering" claim. It appears to be simply wrong.

28. One other comment is appropriate in this regard. The Applicant and its predecessors operated generation, transmission and distribution. Both the legal ownership, and the management/operations, of generation and transmission were separated from distribution, but not at the same time. The legal ownership of transmission was separated in 2008, but management/operations of transmission was separated in 2009. The management/operations of generation was separated in 2002, but the legal ownership of generation was separated in 2009. Thus, the transactions taking place in 2009 were not simply a matter of separating distribution and generation. The transactions required separation of distribution and generation legally (hence the high legal fees), and separationg of distribution and transmission operationally.

29. The above analysis leads us to conclude that the <u>most</u> the Board should consider allowing the Applicant to recover, if anything, is half of the legal ($134,600), plus all of the fees ($3,665) for a total of $138,265.

All of which is respectfully submitted.

.

Yours very truly,
JAY SHEPHERD P. C.

Jay Shepherd

cc: Wayne McNally, SEC (email)
Interested parties (email)