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October 8, 2010

VIA MAIL and E-MAIL

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge St.
Toronto, ON
M4P 1E4

Dear Ms. Walli:

Re: Vulnerable Energy Consumers Coalition (VECC)
Final Submissions – Part I: EB-2009-0278
Algoma Power Hydro Inc. – 2010/2011 Electricity Distribution Rate Application

Please find enclosed Part I of the Vulnerable Energy Consumers Coalition's (VECC) submissions in the above noted proceeding. In accordance with Board Procedural Order #3, Part II will be filed on October 14, 2010.

Thank you.

Yours truly,

Michael Buonaguro
Counsel for VECC

cc: Algoma Power Inc.

EB-2009-0278

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 Algoma Power Inc. pursuant to section 78 of the *Ontario Energy Board Act* for an Order or Orders approving just and reasonable rates for electricity distribution to be effective May 1, 2010.

FINAL SUBMISSIONS
(Part I)

On Behalf of The

VULNERABLE ENERGY CONSUMERS COALITION (VECC)

October 8, 2010

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Vulnerable Energy Consumers Coalition (VECC)

Final Argument

1 The Application

1.1 Algoma Power Inc. ("Algoma" "the Applicant," or "the Utility") filed an application ("the Application") with the Ontario Energy Board ("the Board" or "the OEB") on June 1, 2010 and amended on June 7, 2010, under section 78 of the Ontario Energy Board Act, 1998, for electricity distribution rates to be effective July 1, 2010 and January 1, 2011. Following a round of interrogatories and a technical conference, a settlement conference was held on August 24 and August 25, 2010. The Settlement Proposal (dated September 10, 2010) was filed by the parties indicating that all but three issues were resolved.

1.2 The three unresolved issues were:

A. What is the appropriate method of calculating the average rate adjustments of other distributors in order to calculate the rate increase for the customers of API, and the remaining amount that is payable under RRRP? ("RRRP Adjustment");
B. Should API's proposal to recover amounts in Account 1572 Extraordinary Event Costs be approved? ("Extraordinary Event Costs") and;
C. Should API's proposal to establish a new IFRS Deferral Account be approved? ("IFRS Deferral Account")

1.3 Upon review, the Board indicated concerns regarding the Proposal and a revised version was filed on September 17, 2010, with the same three unsettled issues. On September 22, the Board issued Procedural Order #3 indicating that on September 29th it would review the Revised Proposal and conduct an oral hearing regarding unresolved Issue B. It also indicated that final submission would be made in writing and that for Issue B and C these submissions were due on October 8, 2010. Submissions on Issue A were to be submitted by October 14, 2010.

1.4 Set out below are VECC's final submission on Issues B and C.

2 Extraordinary Event Costs

2.1 In its Application Algoma sought recovery of $412,759 (including interest) which represented costs incurred by Great Lakes Power Distribution (GLPD) in acquiring the distribution assets from Great Lakes Power Limited (GLPL)[1]. While the costs were recorded in Account #1525, Algoma has indicated that they are more properly referred to as Account #172 – Extraordinary Event costs. Algoma claims that the need to separate the distribution business was not within management's control but arose from statutory requirements and the expiry of its Section 71 exemption. It also notes that the costs incurred represent more than 0.5% of Algoma's revenue requirement and are therefore material[2].

Corporate Reorganization Timeline

2.2 Prior to the passage of Bill 35 in 1998, Great Lakes Power Limited (GLPL) operated an integrated generation, transmission and distribution business[3]. Section 71 of the OEB Act, 1998 (part of Bill 35) stated that "a transmitter or a distributor, other than a public utility commission or municipal corporation, shall not, except through an affiliate or affiliates, carry on any business other than transmitting or distributing electricity". However under Section (4) of OR 161/99, GPGL was exempt from Section71 until December 31, 2008 and, as a result, was permitted to carry on the activities of transmission and distribution, together with generation in the same corporation until such date[4].

2.3 Efforts were made by GLPL to separate it operations as they related to generation as much as possible during the market opening timeframe and by May 2002 the operating side of the generation business had been physically and financially separated. Similarly, the transmission and distribution aspects of the business were financially separated but operationally cohabitated within the same management structure. However, from a corporate structure legal-entity

[1] Exhibit 9/Tab 2/Schedule 2, page 1
[2] Exhibit 9/Tab 2/Schedule 2, pages 1-3
[3] September 29, 2010n Transcript, page 20
[4] Exhibit 9/Tab 2/Schedule 2, page 1

perspective GLPL retained ownership of generation as well as transmission and distribution[5].

2.4 In 2007, GLPL applied to the Board for leave to sell its transmission system to Great Lakes Power Transmission (GLPT). Approval was granted in December 2008. However, while the assets were transferred to GLPT, the operation of the transmission system remained with GLPL (along with generation and distribution).

2.5 Finally, in March 2009 an Application was made to the Board to do the following:

- GLPL applied to sell its distribution assets to Great Lake Power Distribution (GLPD) and to have its distribution licence cancelled,
- GLPD applied for a distribution licence,
- GLPT applied for a licence amendment to operate (as well as own) transmission assets, and
- GLPL applied to have its transmission licence cancelled.

Board approval was received in May 2009 and the asset transfer/operation separation was completed in July of 2009. Effective this date, the transmission, distribution and generation activities were carried on in separate stand alone entities[6].

Extraordinary Event Costs Request

2.6 The costs requested relate to the March 2009 Application and the activities associated with establishing “distribution” as separate business. The original Application sought the recovery of $410,695 plus interest. However, at the start of the oral proceeding, this request was reduced to $365,395 in order to exclude $15,000 that were deemed to be transmission-related costs associated with the Application[7]. The requested costs consist of[8]:

- Legal Costs ($269,200) – associated with discussions/applications made with

[5] September 29, 2010, Transcript page 47
[6] Board Decision, EB-2009-0072/EB-2009-0073/EB-2009-0075 and September 29, 2010 Transcript, pages 47-48
[7] September 29, 2010 Transcript, pages 9-10.
[8] VECC #30 a)

the Ministry of Energy, OEB and IESO[9].

- Consultants ($66,390) – 3rd party costs associated with the separation of records as between transmission and distribution[10].
- Internal Costs ($56,440) – staff costs associated with the separation of records as between transmission and distribution[11].
- Administrative ($3,665) – for registration fees with the Ministry of Finance and the IESO.

VECC's Submissions

2.7 Algoma's claim of an extraordinary event is predicated on the view that, with the pending expiration of the legislative exemption, GLPL was required to reorganize in order to comply with Section 71 of the OEB Act. As result, the activities undertaken and the costs incurred were beyond management's control[12].

2.8 VECC has three fundamental issues with Alogma's claim and its characterization as an extraordinary event whose costs are recoverable from rate payers.

2.9 First, Algoma claims that the costs incurred are not equivalent to the transition costs incurred by the municipal corporations who were required to reorganize and incorporate a separate distribution company and that what they are claiming is <u>not</u> analogous to the transition costs related to the corporate re-organization undertaken by municipal corporations[13]. VECC disagrees.

2.10 For both GLPL and the Municipal Corporations the need to re-organize was driven by the new legislation. For GLPL it was the need to comply with Section 71 of the OEB Act. For Municipal Corporations it was the need to comply with Section 142 of the Electricity Act. In the case of the a Municipal Corporation it was so that the generation, transmission and distribution of electricity would be separate from the

[9] September 29, 2010 Transcript, page 32
[10] September 29, 2010, Transcript, page 36
[11] September 29, 2010, Transcript, page 36
[12] Exhibit 9/Tab 2/Schedule 2, page 2 and September 29, 2010 Transcript, page 7,lines 21 to page 8, line 28
[13] September 29, 2010 Transcript, pages 20, lines 1-14 and page 29,line 23 to page 30, line 7

its other responsibilities. In the case of GLPL it was to unbundle and appropriately separate generation, transmission and distribution through corporate reorganization[14]. In VECC's view, the requirements were fundamentally the same – set up separate businesses as result of the legislation related to market restructuring.

2.11 In its RP-1999-0034 Decision[15] regarding transitional costs the Board found that they should be classified into two categories. The first category is costs related to corporate reorganization (i.e., setting up the separate company). The second related to business re-engineering costs of the incorporated company to conform with the new business orientation and requirements. The Board concluded that the costs associated with the first category should be the responsibility of the shareholder; while the business re-engineering costs would be recoverable from rate payers.

2.12 It is VECC's submission that, apart from the Administrative Costs, the costs claimed by Algoma fall into the first category as they are directly related with separating out distribution and setting it up as a separate business. VECC also notes that, taken on their own, the Administrative Costs would fall well below the Board's materiality threshold and therefore not be eligible for recovery.

2.13 VECC's second fundamental issue is that a substantial portion of the costs ($122,830) are associated with the separation of transmission and distribution records[16]. In VECC's submission compliance with Section 71 of the OEB Act does not require that transmission and distribution be separated. Section 71 requires that a distributor or a transmitter not carry out any activity other than transmission or distribution. It does not say that a transmitter can do nothing but transmission and a distributor can do nothing but distribution. Indeed, while Algoma's counsel argued[17] that the reorganization was due to a need to separate transmission and

[14] September 29, 2010 Transcript, page 30, .lines 2-7
[15] Page 31
[16] September 29, 2010 Transcript, page 34
[17] September 29, 2010 Transcript, page 21

distribution, the Algoma staff who were actually involved clearly indicated[18] that "this compliance was directly related to generation and distribution occurring in the same business".

2.14 Further support of VECC's view can be found in the omnibus Application made by GLPL, et. al. in March 2009 which characterized the requirements of Section 71 and the exemption as follows[19]:

> "Pursuant to Section 5(4) of Ontario Regulation 161/99, GLPL was exempt until December 31, 2008 from Section 71 of the OEB Act and was permitted to carry on the activities of transmission and distribution together with generation within the same corporation. In light of the expiry of the exemptions, GLPL has moved to become compliant with the OEB Act."
>
> "The goal is to isolate GLPL's generation business from transmission and distribution. As a result, GLPL also requests that GLPL's transmission and distribution licences be cancelled at the time the applicable commercial transaction is closed. GLPTLP requests that its licence be amended to be a licence to both own and operate the transmission facilities."

2.15 Also, as raised by VECC's counsel during the oral proceeding[20], Hydro One Networks currently operates both transmission and distribution in the same company. Furthermore, despite the comments of Algoma's counsel, VECC is unaware of any specific section of the Electricity Act that suggests this organization is an exception to Section 71 of the OEB Act.

2.16 Based on the view that separation of transmission and distribution is not required under the OEB Act, it is VECC's submission that the separation of GLPL's transmission and distribution businesses was a decision made by GLPL's management and within its control. Therefore, VECC submits that the $122,830 cost of separating the transmission and distribution engineering records does not qualify as an extraordinary event (nor transition costs) and is not recoverable from rate payers. VECC notes that this position is independent of whether or not the Board determines that the balance of the costs associated with claim – which can

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[18] September 29, 2010 Transcript, page 24
[19] EB-2009-0072, Exhibit A/Tab 1/Schedule 3, pages 4 and 7

be viewed as costs associated with separating distribution from generation – are legitimately recoverable from rate payers.

2.17 VECC's third issue is with respect to the internal costs ($56,440) claimed by Algoma as part of the cost of separating the transmission and distribution records. Algoma acknowledges that only a portion of these costs are for overtime or backfilling of existing staff and therefore incremental. However, Algoma was unable to identify this portion of the costs requested.[21] Since only the incremental costs associated with an extraordinary event (i.e., those clearly outside the base upon which rates were derived[22]) are recoverable from rate payers and Algoma is unable to identify these costs, VECC submits that none of the internal costs claimed should be considered as eligible for recovery.

2.18 Finally, in its opening comments[23] Algoma noted that the costs it is requesting are identical in nature to the costs requested by GLPT in its recent rate case and which were accepted as part of a settlement agreement. VECC notes that this "acceptance" was part of a comprehensive settlement agreement[24]. Furthermore, the Settlement Agreement itself specifically noted[25] that:

> "Numerous compromises were made by the Parties with respect to various matters to arrive at this comprehensive Settlement Agreement. The distinct issues addressed in this proposal are intricately interrelated",

As a result, VECC submits that the terms of the GLPT Settlement Agreement as they pertain to one specific item do not represent a precedent for determining the outcome of Algoma's current Application.

2.19 Algoma proposes that the Extraordinary Event costs be allocated to customer classes based on customer numbers and recovered over a 2.5 year period[26]. As noted above, it is VECC's submission that none of these costs should be recovered from rate payers. However, should the Board decide to permit Algoma

[20] September 29, 2010 Transcript, page 21
[21] September 29, 2010, pages 15-17
[22] EB-2007-0673, Supplemental Report of the Board, Appendix B, page VIII
[23] September 29, 2010 Transcript, page 7
[24] September 29, 2010 Transcript, page 31
[25] EB-2009-0408, Settlement Agreement May 17, 2009, page 6

to recover some/all of the requested costs, it is VECC's view that the recovery should not be undertaken in the manner proposed by Algoma.

2.20 If the Board determines some or all of the costs incurred to re-organize GLPL are legitimately recoverable from rate payers, then VECC submits the appropriate way to recover them is on a pro-rata basis using distribution revenues by class as the allocator. The need to re-organize was not driven by customers and customer count is not an appropriate allocator. Rather, if the Board decides it is a legitimate distribution business expense then it should be allocated on same basis as the overall costs of the business are allocated to customers, i.e., using distribution revenues.

3 IFRS Deferral Account

3.1 In its June 2010 Application Algoma requested approval of an IFRS Deferral Account to capture the aggregate impact on the 2011 revenue requirement resulting from any changes to the existing IFRS standards and changes in the interpretation and implementation of such standards[27].

3.2 The need for this account was based on the expectation, at the time of the Application, that utilities would be required to implement IFRS for 2011 whereas Algoma had based its Application on CGAAP and not IFRS accounting principles[28]. In supporting its request, Algoma also noted that such an account had been approved for Hydro One Networks – Distribution in its recent 2010/2011 rate case[29].

3.3 It is VECC's submission that the Board should not approval Algoma's request for an IFRS Deferral Account. In its EB-2008-0408 Report on IFRS the Board stated (page 28):

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[26] Exhibit 9/Tab 1/Schedule 1, page 1
[27] Exhibit 9/Tab 1/Schedule 5, page 1 and SEC #30 b)
[28] OEB Staff #6
[29] OEB Staff #42 c)

> "The Board is of the view that the cost consequences of changes in accounting for rate base and operating costs may be sought to be included in revenue requirement in a similar fashion to cost consequences arising from other events. Recovery from customers of such costs would be subject to testing for accuracy and prudence, as well as rate mitigation mechanisms as necessary. Accordingly, the Board will not establish a deferral account to record increases or decreases in costs resulting from the accounting changes. Distributors under an IRM have options to address unexpected and material cost increases if necessary."

3.4 In the case of Hydro One Networks the Board noted[30] that Hydro One Networks considered the revenue requirement it proposed for 2011 to be consistent with IFRS standards as they were currently understood. The purpose of the deferral account (in Hydro One Networks' case) was to capture any subsequent changes in the IFRS standards. As result, Hydro One Networks application was consistent with the OEB's IFRS Report in that the cost consequence of moving to IFRS (as it was then understood) were incorporated in the proposed revenue requirement.

3.5 In VECC's view, Algoma's case is significantly different in that its Application is based on CGAAP and there is no representation from the Utility that the proposed revenue requirement is consistent with IFRS standards (as they were understood). Given the difference in circumstances, VECC submits the Hydro One Networks approval can not be viewed as a precedent.

3.6 Also, subsequent to the Application, the AcSB issued an Exposure Draft in July 2010 proposing that qualifying entities with rate-regulated activities be permitted, but not required, to continue applying the existing accounting standards for an additional two years (i.e., until 2013). Algoma has indicated that, if the Exposure Draft is approved, it will defer the adoption of IFRS until 2013[31]. It is VECC understanding that in September of this year the AcSB redeliberated its July proposal and determined that for rate regulated entities the implementation of IFRS could be delayed until January 1, 2012[32].

3.7 As result, Algoma is currently not required to adopt IFRS for 2011 and has

[30] OEB Decision, EB-2009-0096, pages 59-60
[31] OEB Staff #8 a)
[32] http://www.acsbcanada.org/decision-summaries/2010/item42260.aspx

indicated that it will not do so. This means that the requested account is not required for 2011.

3.8 Given that granting the deferral account would be inconsistent with the Board's EB-2008-0408 Report and is not required for the test years[33], VECC submits that the Board should not approve Algoma's request.

All of which is respectfully submitted this 8th day of October April 2010

[33] Technical Conference Transcript, August 24, 2010, pages 61-62