VIA RESS

October 26, 2009

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319, 27th Floor
2300 Yonge Street
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Hydro One Networks Inc. (HONI) Changes to Transmission Rates
Supplementary Evidence: Projects D7 and D8
Board File No. EB-2008-0272

Pursuant to Procedural Order No. 7 dated October 20, 2009, attached please find AMPCO's final submission in the above proceeding.

Please contact me if you require additional information or have any questions.

Sincerely yours,

ORIGINAL SIGNED

Adam White

President
Association of Major Power Consumers in Ontario

Copies to: Hydro One Networks Inc.
Intervenors (email)

Association of Major Power Consumers in Ontario
www.ampco.org

372 Bay Street, Suite 1702
Toronto, Ontario M5H 2W9

P. 416-260-0280
F. 416-260-0442

Hydro One Network Inc. (Hydro One) 2009/2010 Electricity Transmission Rates
Final Submission of Association of Major Power Consumers in Ontario (AMPCO)
Supplementary Evidence: Capital Projects D7 and D8

Introduction

In accordance with the Decision with Reasons in EB-2008-0272, Hydro One returned to the Board On September 4, 2009 with additional evidence in support of its request for approval of capital projects D7 and D8. The additional evidence provided was voluminous and largely technical in nature and included supporting material from the Independent Electricity System Operator (IESO) and the Ontario Power Authority (OPA).

AMPCO has reviewed the evidence, as well as the submission by Board staff.

Requirement for a Business Case

AMPCO notes the submission by Board Staff on this application, particularly with respect to the evidentiary obligation of Hydro One for Category 2 projects. Namely, Board filing guidelines require a quantitative cost/benefit analysis, which Hydro One has declined to provide. In addition to its filing guidelines, the Board has also provided specific and clear direction to Hydro One on this matter previously:

"For discretionary projects, the Board expects Hydro One to quantify the reliability and other benefits of the projects"[1].

Board staff has also submitted that, because projects D7 and D8 are not specifically generation connection facilities, they do not fall within the immediate scope of the directives from the Minister and government objectives with respect to the connection of renewable generation, and hence ought to be justified in a manner similar to other category 2 projects.

[1] EB-2006-0501, Decision with Reasons, Aug 16, 2007, p. 45

AMPCO concurs with Board staff's assessment in this regard. Government directives may establish specific projects as non-discretionary, especially when encouragement of such projects may be seen as falling within the Board's obligations under Schedule D of the Green Energy and Green Economy Act. At the same time, the Board's obligation to protect the interests of consumers could be undermined if such directives were interpreted so broadly as to provide justification for not meeting filing guidelines for projects outside the immediate scope of the directives.

Hydro One has stated four types of benefits for the D7 and D8 projects:

1. Relief of congestion/increase of capacity on the North-South tie.
2. Improved reliability for customers north of New Liskeard
3. Avoidance of generation rejection in the north, should the North-South tie become overloaded and IESO use of generation constraints prove insufficient to limit excess southbound flows.
4. Reductions in system losses.

All of these benefits should be susceptible to quantification. Indeed, congestion reduction and reliability improvement benefits were evaluated in project D5 (Cherrywood 500 kV unbundling)[2]. The value of energy loss reduction is also readily estimated. The value of avoiding generation rejection in the North may be less readily determined, since it has not happened to date[3], but a statistical estimate should be possible.

AMPCO submits that the Board should require Hydro One to provide a quantified cost/benefit analysis for projects D7 and D8, consistent with the Board's filing guidelines and with the direction provided to Hydro One in EB-2006-0501.

[2] Hydro One Application EB-2008-0272, Exhibit D1/Tab3/Sch 3/page 15, lines 9-19

[3] Ex I/Tab 10S/Sch 15

In-Service Dates

AMPCO's concern with the absence of a cost/benefit analysis is not simply with the quantum of costs and benefits, but also whether Hydro One's proposal maximizes the present value of these projects. The latter concern is related to the planning and proposed in service dates for these projects.

It is accepted that, if transmission connection facilities are not in place when needed to serve a new load or generation customer, the result is likely to be a stranded customer asset. The resulting unproductive period could potentially negate the original business case for the customer's investment.

The converse is also true. Transmission assets that are put in place before they are used and useful are also stranded assets, since the lack of useful work (e.g., managing an increase in energy supply or demand) while they await the completion of the customer project can negate the business case that provided their original justification.

AMPCO is concerned that Hydro One is proposing to complete these projects and place them in service significantly before they will become used and useful, creating a premature and unnecessary burden on ratepayers.

Concern with allowing these projects to be placed in service early comes from an examination of the evidence provided by Hydro One and indirectly by the OPA.

Hydro One's evidence is summarized in its response to Board Staff interrogatory # 92 where reference is made to 517 MW of hydroelectric generation procured under the Minister's Hydroelectric Energy Supply Agreements (HESA) directive and some 762 MW of renewable generation projects that are in service now or committed.[4] Hydro one

[4] Exhibit I/Tab1S/Sch 92/Page 2-3

continues, stating: "Over 1250 MW of **new** renewable resources would cause southbound flows on the North South Interface to greatly exceed its present operating capability of 1400MW" [5] (emphasis added).

The lists of these two project groups are provided in Hydro One's evidence and are reproduced here for convenience[6]:

Table 1
Capacity and Expected In-Service Date of HESA Facilities as of May 2008

Site	Capacity (MW)	Expected In-Service Date
Lac Seul	12	2008
Hound Chute	10	2009
Upper Mattagami	35	2009-2010
Lower Mattagami	450	2011-2013
Source: OPA		

[5] Ibid, page 3

[6] Exhibit C/Tab 1/Schedule 1

Table 4
Committed and Other Near-Term Generation Projects in Northern Ontario as of Today

Site	Type	Capacity (MW)
In-Service and Committed Resources (Note 2)		
RES I Umbata Falls	Hydro	23
CHP Algoma	Gas	63
In-Service RESOP	Various	5
Committed RESOP	Various	177
RES II Island Falls	Hydro	20
Biomass northwest	Biomass	(Note 1)
RES III Greenwich Windfarm	Wind	99
Total Committed		**387**
Other Resources		
Cameron Falls	Hydro	4
Namewaminikan - 8 km & 12.8 km	Hydro	10
Alexander	Hydro	1
Mattagami Lake Dam	Hydro	6
Pine Portage	Hydro	4
Biomass Atikokan	Biomass	200
Thunder Bay Biomass	Biomass	150
Total Other Resources		**375**
Total by 2013		**762**

Source: OPA
Note 1: This site was included separate from the RESOP potential in the May 20, 2008 letter, but has since been contracted for through RESOP and is included in the committed RESOP site in this Table.
Note 2: Not all in-service resources are included in this Table. Only the resources that were included in May 20, 2008 letter that have since come into service are included in this Table.

With respect to the need for projects D7 and D8, two aspects of Hydro One's claim need to be examined. The first is whether the quantity of "new" renewable resources is in fact 1250 MW as Hydro One claims.

AMPCO asked Hydro One to elaborate on Table 1, to identify both probable in-service dates for the HESA projects and the actual incremental capacity that would be achieved. The results are reproduced below, as Hydro One provided in its response[7]:

[7] Ex I/Tab 10S/Sch 12

Project	Existing (pre-project) Capacity (MW)	Incremental Capacity (MW)	Planned Capacity (MW)	Planned or Actual In-Service Date
Lac Seul (Note 1)	0	12	12	In-Service
Hound Chute	4	6	10	2010
Upper Mattagami	19	16	35	2010
Sub-Total	23	34	57	
Lower Mattagami	486	450	936	2014
Total	509	484	993	

Note 1: Lac Seul Generation Station is adjacent to Ear Falls Generation Station. The capacity of Lac Seul is incremental to the capacity of Ear Falls.

The total incremental capacity for the HESA projects is 484 MW, not 517 MW as claimed in Hydro One in its response to Board Staff interrogatory #92.

Of the 484 MW of incremental HESA capacity, 450 MW or slightly less than 93% are contributed by the Lower Mattagami project, which is not scheduled to be placed in service until 2014.

In its evidence, Hydro One has stated that the Lower Mattagami project may be restricted if the SVCs at Kirkland Lake TS are not in place[8]. However, since the Lower Mattagami project will not be in service until 2014, this condition cannot exist until that time.

There are similar issues with the projects listed in Table 4.

Of the 762 MW of projects listed, 350 MW or approximately 46% of the listed capacity is for generation from burning biomass fuels at Atikokan GS and Thunder Bay GS. Ontario Power

[8] Supplement to EB-2008-0272, Ex B/Tab 1/Sch 1/Page 3, lines 7-13

Generation (OPG) has set in-service dates for these projects for 2012[9], which means they will not affect North-South flows before then.

Moreover, the biomass projects do not add net generation in Northern Ontario. They simply reduce the amount of generation capacity that will be lost at Atikokan GS and Thunder Bay GS when these stations no longer burn coal. These units were rated for a total of approximately 200 MW (Atikokan) + 306 MW (Thunder Bay) = 506 MW prior to coal phase-out. Hydro One argues that, since coal phase-out would have reduced output from these units to zero, the replacement of coal with biomass constitutes an increment in planned generation[10]. This may be true from the perspective of a planner dealing with shifting project plans, but it remains true that these plants will together produce less output after conversion than before.

After biomass conversions of coal plants, the next largest discrete project listed in Table 4 is the Greenwich Wind Farm at 99 MW. When in service, this wind farm will have a maximum output of 99 MW. However, the schedule for in-service is 4th quarter of 2011[11], which means it can have no impact on North-South flows before then.

Reliability Considerations

While it is not a core driver for Project D7, Hydro One and the OPA have noted that, absent the SVCs at Porcupine and Kirkland Lake, reliability for customers north of New Liskeard

[9] http://www.opg.com/power/fossil/biomass.asp

[10] Ex I/Tab 1S/Sch 96

[11] Ex I/Tab 6S/Sch 73/ para a) of response

would be impacted whenever there is a single circuit contingency on the 500 kV line from Porcupine TS to Hamner TS[12].

This situation has been in place for several years now, and the customers of concern have had their part of the system "islanded" three times over the 1995-2008 period[13]. It was not clear from the evidence or interrogatory responses that the islanding events resulted in actual loss of service. While this may be a significant amount of unreliability to attribute to problems on the transmission grid, it is a relatively modest contribution compared to customer unreliability from other causes, especially the distribution system. In its evidence in EB-2009-0096, Hydro One identified its current system average interruption frequency index (SAIFI) for all causes to be approximately 4 outages per year, or 4 x 14 = 56 over a 14 year period, equal to that for the 3 islanding events. Loss of supply events across the entire Hydro One distribution system account for about 6 % of SAIFI, consistent with the historical frequency of islanding in this area.[14]

In sum, the reliability concerns with respect to a 500 kV contingency north of Sudbury are not urgent, at least until the Lower Mattagami project is in service in 2014.

Summary

The evidence that has been provided by Hydro One in support of projects D7 and D8 does not meet the Board's filing guidelines for category 2 capital projects. On this basis, the Board should not approve these projects at this time.

[12] Supplemental to EB-2008-0272, Ex B1/ Tab1/ Sch 1/ Page 2, line 27 to page 3, line 5

[13] Ex I/ Tab 6S/ Sch 71

[14] Hydro One Application EB-2009-0096, Ex A/Tab 4/Sch 1, pages 18-20

In AMPCO's view, the larger issue that needs to be addressed in this application is the degree to which a government directive can support an argument to categorize projects related to the directed project as non-discretionary and therefore less susceptible to Board review. AMPCO respectfully submits that customers and Ontario as a whole will be best served if the Board adopts a strict and narrow interpretation of government directives and thus requires all applications for projects that are not specifically covered by such directives to meet the Board's filing guidelines.

The consequences of not approving these projects for placement in service in 2010 will be minimal, as the large majority of the incremental generation capacity that has been stated as justification for these projects will not enter service until the period Q4 2011- 2014.

Relief Sought

AMPCO requests that the Board not approve projects D7 and D8 for placement in service and rate base for 2010 and direct Hydro One to re-apply for approval of these projects in its next rate application in accordance with Board filing guidelines for category 2 projects, should it continue to believe they are needed.

Costs

AMPCO submits that it participated responsibly in this proceeding. AMPCO respectfully requests that it be awarded 100% of its reasonably incurred costs of participating in this proceeding.

ALL OF WHICH IS RESPECTFULLY submitted this 26th October, 2009.