November 2, 1010

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.
Change to Electricity Transmission Revenue Requirement and Rates
Submission of AMPCO's Final Argument
Board File No. EB-2010-0002

Attached please find AMPCO's final submissions on the above proceeding. This document has been submitted through RESS and two copies will be sent to the Board.

Please do not hesitate to contact me if you have any questions or require further information.

Sincerely yours,

(ORIGINAL SIGNED BY)

Adam White
Association of Major Power Consumers in Ontario

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

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EB-2010-0002

ONTARIO ENERGY BOARD

IN THE MATTER OF THE ONTARIO ENERGY BOARD ACT 1998, S.O. 1998, C.15, SCHEDULE B;

AND

IN THE MATTER OF A REVIEW OF AN APPLICATION FILED BY HYDRO ONE NETWORKS INC. ("HYDRO ONE") FOR AN ORDER OR ORDERS APPROVING A TRANSMISSION REVENUE REQUIREMENT AND RATES AND OTHER CHARGES FOR THE TRANSMISSION OF ELECTRICITY FOR 2011 AND 2012 (THE "APPLICATION")

WRITTEN SUBMISSIONS OF AMPCO

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NOVEMBER 2, 2010

AMPCO ARGUMENT
Submissions to the Ontario Energy Board
OEB File No. EB-2010-0002
Association of Major Power Consumers in Ontario
November 2, 2010

I. Introduction

1. AMPCO has included herein submissions on the following issues:

A. 8.1 Is It Appropriate to implement “AMPCO’s High 5 Proposal” in place of the status quo charge determinant for network service?

B. 9.2 Are Hydro One’s accelerated cost recovery proposals for the Bruce-to-Milton Line and for Green Energy Projects appropriate?

C. 9.1 Are the OM&A and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

D. 4.2 Are the proposed 2011 and 2012 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

E. 6.1 Are the proposed amounts, disposition and continuance of Hydro One’s existing Deferral Variance accounts appropriate?

F. 1.1 Has Hydro One responded appropriately to all relevant Board directions from previous proceedings?

2. Under each issue AMPCO will request a decision of the Board.

A. Issue 8.1 Is It Appropriate to implement “AMPCO’s High 5 Proposal” in place of the status quo charge determinant for network service?

The AMPCO Proposal

3. AMPCO is proposing that a customer’s monthly transmission demand charges be determined on the basis of the average of that customer’s coincident peak demand

on the highest hour on each of the 5 highest peak days of demand in Ontario in the previous 12-month period.

4. AMPCO submits that the fixed monthly network charge should be calculated for each customer based on that customer's demand during the hour of peak demand during the 5 highest peak days of the previous year. This proposal has been called the "High 5 Proposal". Under this proposal a customer's Network Charge remains the same for each month of the year, but a customer would have an incentive to shift usage away from likely peaks in order to reduce the charge applicable for the following year.

5. AMPCO's proposal is consistent with two basic principles of public utility economics:

   (i) that capacity prices should be borne by consumers on the basis of their contribution to peak demand; and

   (ii) that minimizing inefficiency is best achieved by raising prices in inverse proportion to demand elasticities.

6. AMPCO submits that this new rate design should commence July 1, 2012 and be based on electricity usage for the previous 12-month period; i.e., July 2011 to July 1, 2012.

7. AMPCO also proposes that, to the extent possible, the network charge determinant be aligned with the Global Adjustment charge determinant.

History

8. The current Network Charge Determinant is arrived at by calculating a monthly average of total costs allocated to the network assets divided by customers' forecast demand during monthly system peaks.

9. The Network Charge Determinant currently is based on the greater of a customer's monthly coincident peak or 85% of his non-coincident peak demand during working weekdays.

10. AMPCO first proposed that the Network Charge Determinant be altered in EB-2006-0501. The AMPCO proposal then was to remove the existing 85% monthly non-coincident peak demand factor. In addition, AMPCO proposed basing the network charge on demand in the peak months of the year, since peak system demands are only important five or six times a year and it is difficult for customers to be constantly demand responsive. AMPCO argued that changing the charge determinants would improve incentives for those customers that can shift their consumption to avoid peak periods, benefiting all customers by reducing demand on the system during times of peak prices and improving resource utilization.

11. The Board did not accept AMPCO's rate design proposal.

12. In EB-2008-0272 AMPCO proposed the "High 5 Proposal" for the first time. It was supported by quantitative analysis and the expert testimony of Dr. Anindya Sen from the University of Waterloo.

13. In this case, the Board did not reject the AMPCO proposal:

> The Board finds that, overall, AMPCO's proposal has merit. System peak is a significant cost driver in the electricity commodity market and also is of relevance for transmission system planning.

The Board agreed, however, with some intervenors who argued that more study was needed:

> The Board does not accept that AMPCO's quantitative analysis represents a convincing assessment of the likely benefits of the rate design proposal. First, the econometric analysis measured the demand response between periods of time that were relatively close together, whereas AMPCO applied those results to estimate the impact of changes in demand for a

> transmission shadow price, which is an implied price, not a directly observed price. Second, the transmission shadow price represents a saving that can only be realized in the year following the year in which the load shifting takes place. Third, the estimated load shifting is in turn used to estimate the impact on commodity prices.
>
> The Board finds that the evidence supports a conclusion that the proposed rate design would lead to some level of load shifting and some consequent impact on commodity prices. However, the Board has limited confidence that the level of load shifting or the level of net commodity savings is as high as AMPCO has estimated.
>
> While the Board accepts that not all customers would respond the same way as Gerdau Ameristeel, the fact that at least some would respond by load shifting leads the Board to conclude that the proposal should be given further consideration. What is uncertain is the magnitude of the shift, the benefits of the shift, and the resulting impact on other customers.

OEB Decision with Reasons (EB-2008-0272), Pages 68-69

14. The Board directed Hydro One, "to come forward at its next application with (1) further analysis of AMPCO's proposal; and (2) a suitable proposal for implementation for the Board's consideration in the event the Board decides to change the charge determinant.", providing specific direction to Hydro One to follow through on the following expectations of the Board:

> In its further analysis, Hydro One should address the various criticisms which have been made about the AMPCO's analysis (and its expert's analysis) and should attempt to conduct some sensitivity analysis around the potential impacts on commodity prices.
>
> The Board also expects Hydro One to provide a comprehensive analysis of the transmission rate impacts for customers as well as an assessment of any potential adverse impacts on local conditions due to load shifting as described by VECC. Hydro One should also consult with the OPA and the IESO as to any interactions with other demand response programs.

OEB Decision with Reasons (EB-2008-0272), Pages 69-70

15. After unsuccessfully trying to sever the issue from the hearing, Hydro One filed on July 6, 2010 the report of Power Advisory which had been selected to complete the High 5 Charge Determinant Study as directed by the Board.

The Scope of Hydro One's Response to the Board's Direction

16. Hydro One delegated to Power Advisory LLC its responsibility for complying with the direction of the Board:

> "The issues, costs and benefits associated with adopting the High 5 Proposal are fully documented in the attached consultant's report."

Exhibit H1, Tab 3, Schedule 1, Page 4, lines 4-5

17. Power Advisory LLC described its scope of work as follows:

> (1) Provide a comprehensive impact analysis of the likely and potential effects, costs and benefits of implementing the High 5 rate design evaluating:
> - Level of load shift;
> - Transmission cost shifts;
> - Magnitude of impact on commodity cost;
> - Impact on transmission connected customers; who pays and who benefits?;
> - Localized transmission system impacts; and
> - What other potential positive or negative consequences or side effects
> - might such a rate structure result in.
>
> (2) Further analysis of the effect of the AMPCO proposal on long term network investment requirements;
> (3) Review and analyze the various criticisms which have been made about AMPCO's analysis (and its expert's analysis); and
> (4) Identify ways to monitor such a program (i.e. AMPCO's proposal) and measure its effect on commodity prices.

Exhibit H1, Tab 3, Schedule 1,Page 1

18. Power Advisory LLC did not deal with the implementation of the "High 5 Proposal".

Exhibit I, Tab 9, Schedule 23, Page 1, Part a

19. Power Advisory confirmed that its analysis did not consider a number of likely and potential effects, costs and benefits of the High 5 rate design:

> Power Advisory did not perform any quantitative analysis of the effect of the AMPCO proposal on the Ontario electricity market in total, relative to the status quo.
>
> Exhibit I, Tab 9, Schedule 25, Page 1
>
> Power Advisory didn't estimate the economic value to Ontario ratepayers of avoiding additional peaking generation.
>
> Exhibit I, Tab 9, Schedule 26, Page 1, Part a
>
> Power Advisory didn't estimate the magnitude of the reduction in market revenues to generators.
>
> Exhibit I, Tab 9, Schedule 27, Page 1, Part a

AMPCO's Evidence in EB-2010-0002

20. AMPCO submits that Hydro One via Power Advisory LLC did not respond meaningfully to the Board's direction in EB-2008-0272. Instead, Power Advisory LLC merely took every opportunity to criticise the methodology used by Dr. Sen in the report he submitted concerning the "High 5 Proposal".

21. As a result, and in order to further its submission to the Board that the "High 5 Proposal" should be adopted in Ontario, AMPCO submitted Exhibit M, Tab 1. Its purpose was to provide a methodology for analysing the "High 5 Proposal", an analysis not done by Power Advisory LLC, and for Dr. Sen to reassert his position in response to the Power Advisory LLC criticism.

22. The conclusion reached by AMPCO was that industrial customers which reduce demand during peak times would benefit directly from the “High 5 Proposal” by paying lower transmission network charges even though they would bear all the costs associated with ongoing demand management. By placing the risk on customers of anticipating and responding appropriately to actual and absolute critical peak, the “High 5 Proposal” would reward those customers who would participate and only to the extent that they succeed in reducing their demand during critical peaks.

Exhibit M, Tab 1, Page 14

23. AMPCO also submits, however, that the benefits of the “High 5 Proposal” and the industrial demand response which it will induce will be enjoyed by all customers in the form of lower prices, reduced system losses, and lower overall electricity costs.

Exhibit M, Tab 1, Page 14

24. AMPCO also submits that to the extent that these electricity efficiencies are realized by customers, the change will lead to higher industrial productivity, economic growth, higher investment and employment, lower inflation and increased tax revenues to government.

Exhibit M, Tab 1, Page 14

25. The research undertaken by Dr. Sen echoes this position. He says the following:

> “[we] obtain remarkably consistent findings across different estimation methodology. Most industries…respond in varying degrees to contemporaneous changes in price. What is even more robust are the effects of lagged prices. Specifically an increased in lagged prices is significantly associated with higher current consumption - offering evidence that industrials do shift consumption across time in order to exploit the benefits of lower prices during off peak hours.”

Exhibit M, Tab 1, Attachment 1, Page 22

26. Dr. Sen goes on to conclude as follows:

> "[we] also find that lower market demand is associated with a decline in the HOEP. In tandem, these findings offer support to the notion that policies which incurred efficient demand management by industrials will result in positive spill-overs to all consumers."

Exhibit M, Tab 1, Attachment 1, Page 22

27. AMPCO submits that Power Advisory LLC does not disagree with these conclusions; but, rather than deal with them directly they take issue with certain aspects of the methodology relied on by Dr. Sen for similar conclusions in the report he submitted in EB-2008-0272.

Exhibit H, Tab 3, Schedule 1, Page 37

28. Power Advisory LLC on behalf of Hydro One in response to interrogatories and Mitchell Rothman in cross-examination, the specifics of which will be set out below, acknowledge that some of their methological concerns were not based on scientific evidence; some were based on the fact that there was information not available to AMPCO and Dr. Sen when their reports were prepared and some were adequately responded to by Dr. Sen in his submission for this hearing.

The Power Advisory LLC Criticism of AMPCO's Analysis - The Model Was Not Properly Specified

29. Dr. Sen's submission in EB-2008-0272 was for the following purpose.

> [t]o evaluate empirically whether firms, on average, shift their demand for electricity to periods of lower prices (non-peak hours) in response to high prices during hours of peak consumption (peak hours).

EB-2008-0272, Exhibit H, Tab 1, Attachment 1, Page 2, paragraph 6

> [t]o evaluate whether average demand during off-peak hours is higher when average prices during peak hours are high, controlling for prices during the off-peak time period. Therefore, we are attempting to evaluate whether firms actually shift electricity demand from hours in which prices are high (peak demand) to hours where prices are lower (off-peak demand). If such shifting does occur, we would expect an increase in peak prices to be significantly associated with more consumption during off peak hours.

EB-2008-0272, Exhibit H, Tab 1, Attachment 1, Page 2, paragraph 11

30. Dr. Sen's submission in EB-2010-0002 was for the following purpose:

> The fundamental premise in the above analysis is that industrials respond to Real Time Pricing (RTP) and are able to shift consumption to periods of lower prices. In order to investigate the existence of such behaviour, it is necessary to estimate overall demand price elasticities for the industrial sector, as well as changes in prices resulting from movements in overall demand—which itself is due to shifts in consumption by industrials during peak and off peak periods. The relevant research questions are: (1) do industrial consumers shift consumption from peak to off peak hours? and (2) is the Hourly Ontario Electricity Price (HOEP) impacted by these changes in consumption?

Exhibit M, Tab 1, Attachment 1, Page 4

31. Specifically, the following improvements were made to the econometric analyses. First, additional right hand side variables that could also affect trends in electricity demand by industrials independent of the HOEP – such as the daily U.S. – Canada exchange rate, the month specific unemployment rate, indicators for the weekend (or a public holiday) were added. The motivation was to ensure that the estimate of the effect of price on industrial demand was not biased by the omission of these variables. The results conformed with Dr. Sen's earlier submission and were even more robust and statistically significant.

32. Power Advisory LLC discusses at length why the proper elasticities that should have been calculated are the elasticities of substitution: the change in the ratio of on-peak to off-peak in response to a change in the ratio of on-peak to off-peak prices:

> For the analysis of the AMPCO High 5 proposal, the appropriate elasticity is therefore the elasticity of substitution between peak and off-peak electricity. It is not appropriate to use own-price elasticities, because they only measure the change in electricity [demand] that occurs with price change, not the reallocation of electricity usage to different times. Own-price elasticities allow all production conditions to change, including the firm's level of output.
>
> Exhibit H, Tab 3, Schedule 1, Attachment 1, Page 36

> The econometric equations, ..., are also subject to criticism. Even setting aside the relatively low explanatory power of the industry-specific equations, greater effort should be devoted to addressing potential econometric model.
>
> Exhibit H, Tab 3, Schedule 1, Attachment 1, Page 19

> More broadly, the development of this econometric equation does not start with any model of the system to be estimated and therefore has no theoretical basis for the specification of the variables.
>
> Exhibit I, Tab 9, Schedule 34

33. Even under cross-examination, Mr. Rothman maintains that the correct specification is a production function.

> In this new report, Dr. Sen has talked about specifying a production function, but then says, because of the available data, he essentially doesn't use the production function that he specified. He uses a relatively more simple form of his equation, and, therefore, he still hasn't done the -- constrained the problem in the same way that the -- the elasticity substitution estimates do.

> The production function remains a problem, because it is unconstrained, and the estimators remain not robust enough, I think, to be used as point estimators.
>
> Transcript Volume 8, Page 4

34. In place of the methodology employed by AMPCO, Power Advisory LLC proposes the following:

> Estimation of the elasticity of substitution starts with a model which places the appropriate restrictions on the equations. Once such a model is specified, econometric analysis of the firm's behaviour as prices change allows an empirical estimation of the elasticity of substitution. A model that is often used for such estimations is to assume a production function with inputs that include electricity at various times as separate inputs. Then the firm is viewed as choosing an optimal level of expenditures on electricity which it allocates to the different electricity products.
>
> Exhibit H, Tab 3, Schedule 1, Attachment 1, Page 36

> For industrial customers, electricity is a factor of production. The amount of electricity a customer uses depends on the technical and price relationships between electricity and the other factors of production; in other words, on the production function.
>
> Exhibit 1, Tab 9, Schedule 51

35. AMPCO posed an interrogatory to Hydro One in respect of how a firm production function can be used to estimate aggregate industry responses to changes in relative prices and received the following response:

> The responses to changes in relative prices are estimated from the empirical results of econometric estimation of the demand equations derived from the production functions of the firms.
>
> Exhibit 1, Tab 9, Schedule 52, Page 2, Part d

36. AMPCO also requested, by way of interrogatory, data, or appropriate references to a source of publicly available data, that would enable a firm production function to be estimated, so that it could estimate the elasticities of substitution recommended

by Power Advisory LLC. Power Advisory responded that it has no such data and that no such data is available:

> Power Advisory has no such data. Such studies have generally not used publicly available data but rather have had access to individual customer data.
>
> Exhibit I, Tab 9, Schedule 52, Page 2, Part c

> And, remember, we did not do any elasticity estimates. The elasticity estimates that are in this table 10 are all taken from an elasticity estimate made in the early '90s. And the reason, quite legitimate reason, that AMPCO can't do elasticities of substitution, as they point out in their report, is that really to do an estimate of elasticity of substitution, you need individual firm data. Now, in the early '90s, those estimates were made by analysts within Ontario Hydro, and they had individual firm data. You can't get it anymore, for good reasons. And so AMPCO is doing own-price elasticities.
>
> Transcript Volume 7, Page 182, lines 15-25

37. In his testimony, Dr. Sen explained why he did not estimate a production function:

> I did not use those specific functional forms, but for two good reasons.
>
> One reason is that you need individual-level data, either at the level of the firm or the household, to estimate the specific functions. So, for example, not only do you need data on electricity consumption of a firm or a household, you also need data on how they allocate their expenditure on other types of energy consumption, as well as in terms of the consumption of other goods. Without such information, you simply cannot estimate these functions. So that is the first reason why I did not use such functions.
>
> What I did do is I used well-established demand specification that is well-suited for the use of these aggregate data.
>
> But perhaps more importantly, even if I did have such individual level data, I would not have used this methodology. The reason being

> is that when you use these specific methodologies, which have been outlined in the PAG report, what happens is that you get a relationship, which is the response of the ratio of demand to the ratio of price. So for example, how the ratio of on-peak demand to off-peak demand changes to corresponding shocks in the ratio of off-peak to on-peak prices. So the point being is that what you do get is an idea of the change in relative demand to a change in relative prices.
>
> But the objective of my study was a bit different. What I wanted to understand was the effect of a change in contemporary price, as well as a change of a lag price on contemporary demand. So in doing so, you have a very clear separation of the magnitude of these effects.
>
> You cannot obtain such a separation of magnitude of effects if you used the methodologies which have been put forward by PAG.
>
> Transcript Volume 10, Pages 25-26

38. AMPCO submits that Power Advisory LLC is incorrect in its assumption that a production function can be estimated using aggregated data such as is publicly available in Ontario and on which AMPCO must rely.

39. AMPCO submits, as well, that Leontief or Constant Elasticity of Substitution (CES) functional forms are relevant and appropriate only when data is available at the level of the household or firm and not aggregated. This is a critical flaw in the Power Advisory LLC criticism of Dr. Sen's analysis.

40. AMPCO submits that the methodology used by Dr. Sen, as described above, to understand the effect of the change in contemporary price, as well as a change in lag price on contemporary demand was appropriate.

41. In summary, the revised AMPCO study makes the following contributions; it presents consistent findings across Feasible Generalized Least Squares (FGLS) and Instrumental Variables (IV) estimates. Some industrials reduce their demand in

response to higher prices. Specifically, our results suggest that a 10% rise in the HOEP is significantly associated with a 0.3-0.7% drop in industrial demand. Perhaps more importantly, coefficient estimates of lagged electricity prices are statistically significant for most industries – implying that even in the absence of any strong regulatory incentive. Further, the marginal effect of electricity load on the HOEP during peak hours for summer months exceeds the impacts of corresponding effects of demand during off peak hours.

Exhibit M, Tab 1, Attachment 1, Pages 4-5

42. These estimates are remarkably robust irrespective of which year (2005 – 2008) on which the estimation is based. In tandem, these results suggest that network charge determinants, which give industrials an incentive to shift demand from on-peak to off-peak time periods, would result in considerable benefits to all consumers. This is reflected in the data which demonstrates considerable load shifting by some industrials in response to the rather limited regulatory incentive that currently exists. As a result, AMPCO is confident that a policy that yields clearer and a greater marginal incentive for firms to reduce consumption during peak hours will elicit a corresponding reaction from large industrials that constitute a significant portion of total electricity demand in Ontario.

The Estimates Are Not Reliable

43. The Power Advisory LLC report repeats a number of criticisms made by intervenors and Hydro One of Dr. Sen's report in EB-2008-0272:

> VECC provided several other comments on Dr. Sen's analysis. Most critically, VECC suggests that the demand equation may not be properly specified and may be subject to bias as the price elasticity coefficient would change, a result of not including important explanatory variables. HONI raises a technical econometric concern, namely that the two independent price variables, the on-peak and off-peak prices are not independent.

Exhibit H, Tab 1, Schedule 3, Attachment 1, Page 15

44. The specific criticisms are set out in the Power Advisory LLC report:

> Even if we were to accept Dr. Sen's approach as valid, several of its aspects call into question the robustness and degree of statistical bias of these elasticity estimates. Many of these points were made by other participants in EB-2008-0272, as we detailed in Section 2.2.3 of this report. These results are questionable for several reasons:
>
> - The omission of explanatory variables can in part explain the relatively low observed R2, as Dr. Sen agreed.
> - It also can lead to bias in the estimated coefficients if the included variables are positively correlated with the omitted variables and therefore pick up some of their effect.
> - There is multicollinearity because the independent variables are correlated with each other, but Dr. Sen did not report the degree of correlation. Multicollinearity can make the coefficient estimates suspect in relation to each other. As Dr. Sen said at the hearing, multicollinearity makes it very hard to disentangle the effect of lagged from current prices. In response to an information request from VECC, AMPCO agreed that there is multicollinearity but said that it had been dealt with appropriately by clustering. However, clustering does not address the main problem of the consequent unreliability of the coefficient estimates due to the multicollinearity.
> - Dr. Sen's estimated coefficients are not robust under different estimation time frames and different specification of the independent variables.

Exhibit H, Tab 1, Schedule 3, Attachment 1, Pages 38-39

45. AMPCO submits that Dr. Sen's report in EB-2010-0002 addresses these concerns:

> Sen (2009) contains some analyses designed to address the above questions. However, this paper adds to Sen (2009) through the use of additional data from 2008 as well as new information on total industrial demand and demand by electricity generators, distributors, and transmitters. Further, the empirical estimates have been redone using Feasible Generalized Least Squares (FGLS) which account for first order autocorrelation and unknown heteroskedasticity. We also evaluate the sensitivity of our findings through the use of Instrumental Variables (IV) intended at correcting for measurement error and pooling the data across all years of our sample.

> Finally, more right hand side controls are added (monthly unemployment rates, the daily exchange rate, and dummy variables for weekends and holidays) to capture the effects of other potential determinants of industrial electricity consumption.

Exhibit M, Tab 1, Attachment 1, Page 4

> We obtain consistent findings across Feasible Generalized Least Squares (FGLS) and Instrumental Variables (IV) estimates. Some industrials reduce their demand in response to higher prices. Specifically, our results suggest that a 10% rise in the HOEP is significantly associated with a 0.3-0.7% drop in industrial demand. Perhaps more importantly, coefficient estimates of lagged electricity prices are statistically significant for most industries – implying that even in the absence of any strong regulatory incentive - firms are responsive to price signals and do shift demand between peak and off peak periods. Further, the marginal effect of electricity load on the HOEP during peak hours for summer months exceeds the impacts of corresponding effects of demand during off peak hours. These estimates are remarkably robust irrespective of which year (2005 – 2008) our estimation is based upon. In tandem, these results suggest that network charge determinants, which give industrials an incentive to shift demand from on-peak to off-peak time periods, would result in considerable benefits to all consumers.

Exhibit M, Tab 1, Attachment 1, Page 5

46. The Power Advisory LLC report goes on to criticise Dr. Sen's submission in EB-2008-0272 because of a, "relatively low observed R2" and "the omission of explanatory variables".

Exhibit H, Tab 1, Schedule 3, Attachment 1, Page 38

47. The 'R- Squared' statistic describes how well the model fits the data, and, by construction, lies between 0 and 1. An R-Squared value which is closer to 1 implies that the statistical model used to analyze the data, is actually doing a good job of explaining observed trends in the dependent variable (in this case electricity demand). In his updated submission, Dr. Sen reports R Square values that are in most cases greater than 0.9, implying that the statistical model used in the updated

analysis is explaining more than 90% of the variation in electricity demand over time. This improved R Squared was acknowledged by Mr. Rothman during cross-examination.

Transcript Volume 8, Page 5

48. The reason for the improved R Squared can be attributed to: (1) the use of more explanatory variables that can plausibly impact trends in demand by industrials independent of the HOEP, and (2) the reliance on a different estimation methodology (Generalized Least Squares, "GLS") that allows one to correct statistical estimates of coefficient estimates and standard errors from unobserved time-specific shocks, which are difficult to control for, but that can affect demand or supply and ultimately the HOEP. For example, the closing of a significant power plant – perhaps nuclear – which may have a persistent effect over a few days.

49. Dr. Sen's previous estimates were based on an acceptable estimation methodology known as Ordinary Least Squares (OLS). It is important to emphasize, however, that from a general perspective, there is limited difference between Dr. Sen's OLS and GLS estimates of the effects of the HOEP on electricity demand.

50. Mr. Rothman agreed.

> The results, in general, the elasticity estimates are in the same range as the original elasticity estimates.

Transcript Volume 8, Page 6

> And, also, the estimators from his new report are robust in the sense that they are reasonably consistent in terms of their levels of magnitude -- in terms of their signs. They don't change signs, in general. They don't move around a lot. They tend to be statistically significant.

Transcript Volume 8, Page 4

51. AMPCO submits, therefore, that the criticism of this aspect of the work of Dr. Sen is no longer a concern.

52. Power Advisory also criticised Dr. Sen's work because of the possibility of multicollinearity, which occurs when right hand side explanatory variables are highly correlated with one another, making it difficult to disentangle the relationship between the dependent variable (in this case electricity demand) and specific right hand side variables (current and lagged values of the HOEP).

> There is multicollinearity because the independent variables are correlated with each other, but Dr. Sen did not report the degree of correlation. Multicollinearity can make the coefficient estimates suspect in relation to each other. As Dr. Sen said at the hearing, multicollinearity makes it very hard to disentangle the effect of lagged from current prices. In response to an information request from VECC, AMPCO agreed that there is multicollinearity but said that it had been dealt with appropriately by clustering. However, clustering does not address the main problem of the consequent unreliability of the coefficient estimates due to the multicollinearity.

Exhibit H, Tab 1, Schedule 3, Attachment 1, Pages 38-39

53. AMPCO submits that the analysis of Dr. Sen in EB-2010-0002 does not suggest the presence of multicollinearity, because in many cases the current as well as the lagged values of the HOEP are statistically significant.

54. Mr. Rothman agreed.

> Dr. Sen's analysis, by the use of the generalized least squares methodology, certainly addresses the issue of multicollinearity, and his revised -- his new equations, his new estimates, have much higher R-squareds, in part, because he has added variables.

Transcript, Volume 8, October 1, Page 4

55. Power Advisory LLC additionally criticizes Dr. Sen's estimates as not being "robust":

> Dr. Sen's estimated coefficients are not robust under different estimation time frames and different specification of the independent variables.
>
> Exhibit H, Tab 1, Schedule 3, Attachment 1, Page 39

56. Power Advisory LLC suggests that AMPCO's estimates are unreliable because "point estimates" cannot be used to estimate a demand response to relatively large changes in price:

> When calculating the change in electricity prices faced by customers. AMPCO essentially assumes that the current transmission shadow price is zero, thus overstating the price change used to calculate the elasticity response. Partly as a result, the price change is over 150%, a price shock so large that it may not be appropriate to apply the econometric elasticity estimates to a price change of this magnitude.
>
> Exhibit H, Tab 1, Schedule 3, Attachment 1, Page 19

> My concern is that the estimators, while robust in a sense -- and I said in our report that relative to some econometric estimates, these estimators are reasonably robust, but for use as point estimates, they have a fair amount of variance across the years.
>
> Transcript Volume 8, Page 5, lines 12-16

57. AMPCO's estimates of elasticity do vary from year to year. In fact, with each update of the data, Dr. Sen's estimates are stronger (the coefficient values increase) and are more robust (the t-statistics increase).

EB-2008-0272, Exhibit H, Tab 1, Attachment 1
EB-2010-0002, Exhibit M, Tab 1, Attachment 1

58. The Power Advisory LLC criticism that this phenomena means that the AMPCO methodology or results are unreliable is not fair. The intuition is straight-forward. Competitive pressures on Ontario industry are relentless. Industrial companies are

always seeking ways to increase production and reduce costs, in other words to be more productive and efficient. Rising electricity costs, both in absolute terms and as a proportion of input costs, tend to attract more attention to energy pricing over time. As well, as customers gain experience in Ontario's electricity market, they learn how best to manage their consumption in relation to changes in prices and rates. AMPCO's findings, that elasticities increase and become more statistically significant over time, confirm this intuition.

59. If anything, the estimated price elasticities reflect changes in consumption to relatively modest changes in prices. AMPCO expects that the elasticity would be much larger in the presence of very large changes to prices. AMPCO believes, therefore, that its calculations are an under-estimate of likely consequences.

60. In summary, Mr. Rothman agrees that most of his concerns have been met:

> He has used reasonably well-accepted econometrics techniques -- well-accepted econometric techniques. I don't have any concerns with those techniques.
>
> They are using more up -- more recent data than the earlier estimates, and I think that that makes a contribution.
>
> So I think that's a reasonable -- I think that they do improve the previous results in the sense of having better -- as we have said, better goodness of fit. They have a better specification. They have included more variables. So it is a somewhat more careful analysis than the original analysis was.

Transcript Volume 8, Pages 5-6

The Global Adjustment Will Offset Any Reductions in Price

61. Power Advisory LLC asserts that AMPCO didn't analyze other potential costs, such as market revenues to generators and the impact of the Global Adjustment:

> The AMPCO analysis is concentrated on transmission demand and commodity prices. AMPCO did not analyze other potential societal costs such as the reduction in market revenues to generators. In Ontario, as a result of the Global Adjustment mechanism and the fact that a significant portion of the market is under contract, reductions in HOEP can result in increases in the Global Adjustment.

Exhibit H, Tab 1, Schedule 3, Attachment 1, Page 10, footnote 22

62. It should be noted that Power Advisory also did not analyze these other economic impacts:

> Power Advisory didn't estimate the magnitude of the reduction in market revenues to generators.

Exhibit I, Tab 9, Schedule 27, Page 1, Part a

> [The effect on the Global Adjustment of a reduction in HOEP] … was beyond the scope of the analysis requested by Hydro One in its RFP.

Exhibit I, Tab 9, Schedule 62, Part b

63. AMPCO submits, therefore, that there is no evidence to suggest that analyzing "these other economic impacts" would have any effect on the conclusions reached by AMPCO in its submission.

Position of Board Staff

64. Board staff's characterization of the Network Charge Determinant in the present rate design contains a fundamental inaccuracy.

Brdstaff_SUB_HONI_20101022, Page 26

65. Board staff maintain, in defending the present network charge determinant and suggesting that it should remain different from the rate design proposed in

amendments to the Global Adjustment contained in Ontario Regulation 429/04, that customers can cope with rates that are complicated.

Brdstaff_SUB_HONI_20101022, Page 28

66. AMPCO submits that the position of Board Staff is disingenuous and misses the point. Ontario electricity customers are accustomed to dealing with complexity in Ontario's electricity market. The focus should not be on complexity, it should be on the fact that rates, as designed, are conflicting, counter-productive and contrary to the statutory objectives of the Board and the policy objectives of the Province as contained in Ontario Regulation 398/10.

67. AMPCO submits that whether or not customers can cope with complexity is not the point. Complexity is not a virtue of the status quo; it is a vexation. Staff proposes to continue indefinitely a rate design at odds with the government's policy regarding the Global Adjustment, which creates unnecessary "complications" that are an impediment to efficiency, to streamlining operations, and to investment. Contradictory, counter-productive and conflicting rates are a drag on the Provincial economy.

Experience with the High 5 Proposal in Other Jurisdictions

68. AMPCO's proposed rate design is not new. The PJM market (including Pennsylvania, New Jersey, Maryland and 15 other States) and Texas have similar rate structures to the rate design proposed by AMPCO. In the EB-2008-0272 proceeding, AMPCO presented testimony of Mr. MacDonald of Gerdau Ameristeel who explained how his company has responded to similar rate structures in New Jersey and Texas in order to achieve significant cost savings. He testified that Gerdau's Ontario facilities would respond the same way if the High 5 Proposal were implemented.

EB-2008-0272 Decisions with Reasons, Page 65

69. In EB-2008-027 Decision with Reasons, the Board found "..the testimony by Mr. MacDonald of Gerdau Ameristeel to be compelling evidence as to the expected reaction to such a rate design. His company has responded to similar rate structures in other jurisdictions and would do so in Ontario as well."

EB-2008-0272 Decisions with Reasons, Page 69

70. In the current proceeding, industry representatives Mr. MacDonald of Gerdau and Mr. Dottori of Tembec Inc. provided testimony on how their companies would respond to a new rate design with a 5 CP methodology.

> Mr. Macdonald: We operate steel recycling mills in many jurisdictions in North America, and a number of them have a similar approach to the AMPCO proposal with a 5CP type of methodology. It is not exactly the same, but it is very similar.
>
> And so I am confident that our actions here would, like in these other markets, demonstrate that we would take advantage of the price signals and use these new tools to control our electricity costs.

Transcript Volume 10, Page 29

> Mr. Macdonald: We are doing all of these -- all of this work in these other jurisdictions, because the proper market signal is there, and we would do it here if the proper market signal was here.

Transcript Volume 10, Page 32

> Mr. Dottori: I think the bottom line is that we do respond to price signals in the marketplace. We have been for very many years. It is not just something that is new. And that the 5CP proposal for network charge determinant would improve that response.

Transcript Volume 10, Page 32

71. The evidence of Mr. MacDonald and Mr. Dottori establishes that a High 5 Proposal has the effect on consumers which Dr. Sen predicts and which AMPCO recommends.

A Suitable Implementation Proposal

72. One of the directions to Hydro One in the Board's decision in EB-2008-0272 was for it, "to come forward at its next application with…a suitable proposal for implementation for the Board's consideration in the event the Board decides to change the charge determinant."

EB-2008-0272 Decisions With Reasons, Page 69

73. As indicated above, Power Advisory LLC did not address any implementation issues.

Exhibit I, Tab 9, Schedule 23, Part a

74. Hydro One's outline of implementation considerations are set out below:

> 1. As noted in the consultant's report at page 24, it would be appropriate to have a complete year in which transmission customers understood the consequences of changing the Network pricing methodology so they have an opportunity to modify their behaviour with full knowledge of the consequences of not doing so.
> 2. The High 5 methodology is based on consumption in the prior year. The 2010 data would not be available in time to determine the 2011 Network payments effective January 1, 2011.
> 3. The IESO have indicated they would require at least 4 months to implement the necessary tool and business process changes, as well as any required market rules amendments. The IESO would initiate implementation activities only after the OEB has rendered a decision on this issue, which per Procedural Order No.1 in this proceeding, is expected on or

about January 7, 2011. The IESO have also indicated that, given past experience in dealing with issues of this similar nature, any number of issues could arise during implementation that may require further input from the Board or additional stakeholder consultation.[1]
4. Time will be required to update the Uniform Transmission Rates Schedules to reflect the High 5 methodology for the Network Service Rate.
5. All the other transmitters in Ontario will need to assess the impact of this new methodology on their Network charge determinants.
6. Hydro One Networks will need to develop settlements processes necessary to verify the IESO bills and advise of any concerns within the mandated 6 day period of receiving the IESO payments.

As noted by the consultant on page 56, there is also a potential issue associated with the fact that distribution connected customers (e.g. large users) are charged for transmission service on the basis of the current methodology for developing Retail Transmission Service Rates (RTSR) applicable to distribution customers. The derivation of RTSR charges is currently aligned with the Uniform Transmission Rates methodology, and adopting the High 5 Proposal for the transmission Network Service rate alone will result in unequal treatment between large users connected to the transmission versus distribution systems. A January 1, 2012 implementation date would allow the Board time to review and consider the need to change the RTSR methodology, and how the transition to new RTSR rates for individual LDCs would be addressed.

A January 1, 2012 implementation date would allow time to address the issues noted above and would permit the establishment of a process to resolve any further issues that could arise during implementation.

Exhibit H1, Tab 3, Schedule 1, Pages 5-6

[1] This was supported in comments by Mr. Lanni (IESO) during the Hearing of Motion (July 20, 2010) at page 14 of the Motion Record, starting at line 18: "With respect to implementation, January 2011 isn't feasible, and that we know for sure… it will take at least four months… we would have to consider wither or not there would be rule changes required."

75. AMPCO believes that to be reasonable and to provide a workable and practical time period for implementation of the "High 5 Proposal", it should be effective as of July 1, 2012, based on customer experience between July 1, 2011 and July 1, 2012.

Conclusion

76. AMPCO proposes a simple policy change: that a customer's monthly transmission demand charges be determined on the basis of the average of that customer's coincident peak demand on the highest hour on each of the 5 highest peak days of demand in Ontario in the previous 12-month period.

77. AMPCO's believes that this policy is consistent with the mandate of the Board. Specifically, to enact energy policy that promotes efficiency, promotes efficient demand management and protects the interests of consumers.

78. AMPCO acknowledges the comments and constructive criticisms that were offered on our last submission. AMPCO believe that all of them have been addressed.

79. First, AMPCO has conducted a scientific study of the response of industrials to the HOEP and the effects of their consequent load shifting. The research paper is a significant contribution to the almost non-existent literature on the relationship between electricity demand and prices in Ontario following the 2002 reforms. The study was conducted using publicly available data from the IESO (over multiple years) and employing sophisticated but conventional statistical techniques and tools. Our results are robust to all the concerns that were raised. Some industrials that are directly connected to the transmission grade engage in a significant amount of load shifting in response to expectations of higher prices during peak periods. This results in a lower demand during peak hours and a consequent reduction in the HOEP, which benefits all consumers. Therefore, a network charge based on consumption during peak hours should have similar effects.

80. Second, AMPCO thinks that the proposed charge is simple, transparent, and more importantly gives firms an incentive to reduce demand during peak hours.

81. Third, AMPCO's belief in the viability of the proposed network charge is premised on the success of similar initiatives in other jurisdictions in the United States and the response of some AMPCO members that have industrial facilities in such states. Our design of the network charge is based on these initiatives.

82. Fourth, a relevant concern is whether the change to the network charge determinant will be fair given that there might be a slight increase in prices during off peak hours and therefore, some degree of higher costs to consumers who use electricity during these hours.

83. AMPCO believes that the benefits from reduced consumption during peak hours strongly overwhelm such costs. Further, consumers, on average, realize the importance of reduced consumption during peak hours and the resulting benefits to conservation and energy efficiency.

84. AMPCO acknowledges that there are a range of factors the Board must consider in establishing electricity transmission rates. The statutory objective of the Board is not to protect some consumers at the expense of others; it is to protect consumers overall. Perpetuating inefficiencies, extending cross-subsidies among customer classes, and proliferating contradictory and counter-productive rates has to be seen as deleterious to the interests of consumers.

85. For too long, the incentive value of rates has received insufficient attention. It may be true that some consumer interests are indifferent to the incentives rates provide. It is certainly true that some consumer interests seek to maintain the subsidies that the current rate structure confers upon them. Industrial customers are not indifferent. Industrial customers modify when and how they consume

electricity to minimize the cost of electricity. When the rate structure incentivizes demand reduction during the spring freshet, industrial customers will reduce demand: even when two-thirds of Ontario's generation capacity is sitting idle, the network is at one-third capacity and customers are paying for water to be spilled and nuclear generation to be curtailed. This is the status quo. It is inconsistent with the government's policy. It is inconsistent with statements of the Board. It is inefficient and deleterious to the interests of consumers. It is not sustainable.

86. There is ample evidence of the benefits that will flow to all customers from approving the change AMPCO seeks. AMPCO submits that the substantive criticisms levied against the AMPCO submission have been addressed.

87. AMPCO submits, with respect, therefore, that the "High 5 Proposal" should be adopted by the Board to be implemented in Ontario on July 1, 2012 based on the experience of customers between July 1, 2011 and July 1, 2012.

B. Issue 9.2 Are Hydro One's accelerated cost recovery proposals for the Bruce-to-Milton line and for green energy projects appropriate?

Summary Conclusion

88. In this section AMPCO discusses the request of Hydro One that 100% of the annual Construction Work In Progress ("CWIP") for the Bruce-to-Milton Circuit Line be subject to accelerated cost recovery. For the reasons set out below AMPCO submits that this request be rejected by the Ontario Energy Board (the "Board") because Hydro One has not satisfied the seven factors set out by the Board in Board Report EB-2009-0152 "Report of the Board – The Regulatory Treatment of Infrastructure Investment in connection with the Rate-regulated Activities of Distributors and Transmitters in Ontario", issued on January 15, 2010 ("the Report") which

determine whether a departure from conventional regulatory mechanisms for cost recovery should be considered.

Hydro One's Proposal

89. Hydro One is proposing that its 500kV Bruce to Milton Circuit Line project which has already been approved by the Board in a Section 92 proceeding, be subject to accelerated cost recovery. Specifically, Hydro One is proposing that during the construction phase, 100% of CWIP expenditures for the project be treated as if they were added to rate base and the resulting financial carrying costs (annual long-term debt, short-term debt, Return on Equity and income tax costs) be included in annual revenue requirement. This treatment results in an incremental revenue requirement impact of $43.6 M in 2011 and $26 M in 2012. If Bruce to Milton is placed in-service in 2012, there is an additional $36.6 M revenue requirement impact in 2012 including depreciation.

Exhibit A, Tab 11, Schedule 5, Page 7

90. This project will contribute about 3.5% of the rate increase in 2011 and a lesser amount in 2012.

Exhibit A, Tab 15, Schedule 1, Page 16

91. Hydro One indicated in its evidence that this proposed treatment is consistent with the methodology and meets the parameters as set by the Board for this alternative cost recovery mechanism in the Report.

Exhibit A, Tab 11, Schedule 5, Page 1

92. The Report emphasized that "conventional mechanisms continue to be appropriate and should therefore remain the core component of the Board's regulatory treatment of infrastructure investment."

Exhibit K2.3, Page 10:

EB-2009-0152 Report of the Board, "The Regulatory Treatment of Infrastructure Investment in connection with the Rate-regulated activities of Distributers and Transmitters in Ontario."

93. The Board also indicated that the applicant will be required to demonstrate that a requisite relationship exists between the alternative mechanism requested and the demonstrable risks and challenges faced by the applicant in relation to the investment being made. The Report says that in considering a proposal for one or more alternative mechanisms, the Board will evaluate seven factors.

Exhibit K2.3, Page 21:
EB-2009-0152 Report of the Board, "The Regulatory Treatment of Infrastructure Investment in connection with the Rate-regulated activities of Distributers and Transmitters in Ontario."

94. AMPCO submits that Hydro One failed to provide sufficient evidence to establish that the seven factors had been satisfied and, therefore, that a departure from conventional regulatory mechanisms for the Bruce to Milton project should be permitted. AMPCO takes this position with respect to these seven factors set out below for the following reasons:

Need for the Project

95. The Bruce to Milton project has already received Section 92 approval (2009) confirming the need for the project. Work is currently underway and the project has a planned in-service date of December 31, 2012. Hydro One plans to complete the project regardless of whether accelerated cost recovery of CWIP is approved by the Board. Need is, therefore, not a real issue with which the Board must now concern itself.

Public Interest Benefits/Benefits to Ratepayers

96. Hydro One's pre-filed evidence says "Utilization of this "Accelerated Cost Recovery of CWIP" mechanism for the BxM project will provide a smoothing, or phased-in

effect on rates, and mitigate the rate impact that would otherwise take place when this large new facility comes into service. This approach will also reduce Hydro One's borrowing costs to the benefit of ratepayers, due to the resulting improved cash flow…."

Exhibit A, Tab 5, Schedule 11, Page 6

97. Hydro One provides more detail on these benefits in a Board Staff interrogatory response wherein the Net Present Value (NPV) of revenue requirement, cost impact on a Discounted Cash Flow (DCF) basis, and total expenditures for the project are calculated for CWIP in rate base compared to the standard method (AFUDC capitalized). The NPV of revenue requirement calculation shows a small benefit to ratepayers of $9.7 M using CWIP in rate base.

Board Staff Interrogatory Exhibit I, Tab 1, Schedule 122

98. When VECC asked during the hearing for the calculation to be redone to reflect updated AFUDC rates, Hydro One admitted that the benefit of CWIP in rate base to ratepayers was less ($6 million) confirming the sensitivity to AFUDC rates used in the calculation.

Undertaking J6.8

99. This point is further emphasized in the above Board Staff interrogatory response which updates the overall project cost of the Bruce to Milton project using the standard approach from $753 M to $762.9 M because the $753 M was based on earlier AFUDC assumptions.

Board Staff Interrogatory Exhibit I, Tab 1, Schedule 122, Page 1

100. Hydro One says "In this case, it shows that CWIP in rate base is actually less costly to ratepayers than the standard approach, although the difference is not large and

it may not always be the case. The result is affected by spreads between the blended debt and equity rate of return and the AFUDC rate which can vary".

Board Staff Interrogatory Response Exhibit I, Tab 1, Schedule 122, Page 3

101. Under cross-examination the witness Mr. Gregg agreed that we should not assume that recovering CWIP will always be to the benefit of the ratepayer. It could vary on a case-by-case basis.

Transcript Volume 3, Page 200, line 23

102. Under cross examination, the witness Mr. Struthers confirmed that the calculation is sensitive to the AFUDC rate but is more sensitive to the discount rate used:

> MR. SHEPHERD: I am right, am I not, that the comparison is not as sensitive to the AFUDC as it is to the discount rate? Isn't that right?
> MR. STRUTHERS: The model is sensitive to the discount rate, yes.

Transcript Volume 7, Page 95, line 22

103. AMPCO submits that as the assumptions and economic data for this project are modified in the model, CWIP in rate base may not necessarily be less costly for ratepayers on a lifetime NPV revenue requirement basis than the standard approach.

104. Under the CWIP in rate base approach, customers are being asked to pay for the project at an early point before the asset is used and useful; the amount collected is higher in the early years and lower in the later years. It seems that ratepayers will be out of pocket and paying cumulatively more until 2024.

Undertaking J6.6

105. To accommodate CWIP payments, AMPCO submits that ratepayers may have to increase their borrowing or defer/abandon other spending. Many of AMPCO's members will have to borrow at a higher rate than Hydro One to allow them to

conduct other parts of their businesses. Under cross-examination, Hydro One acknowledges that the cost of capital for Hydro One is lower than its industrial customers:

> MR. SHEPHERD: All right. The discount rate in your formula -- oh, let me just move aside for a second. Your industrial customers, of course, don't have that; right? They have a mix of capital requirements, the same as you; right?
> MR. STRUTHERS: Yes, they would.
> MR. SHEPHERD: Because you have a lower beta than they do, typically your cost of capital would be lower than theirs; right?
> MR. STRUTHERS: That is correct, yes.

Transcript Volume 7, Page 80, line 28

106. In its analysis, Hydro One does not take into account the borrowing costs of ratepayers:

> MR. FAYE: And it brought out the conclusion that overall, ratepayers benefited on a present-value basis. I wanted simply to ask you, in that analysis, did you account for the cost of capital of your customers at all? Sir, is there an element in there?
> MR. GREGG: For our customers?
> MR. FAYE: Yes. I think Mr. Crocker asked you that when you asked them to pay early, they may have to go borrow more money. I think your response was you didn't consider that, so...
> MR. GREGG: No. There would be no accounting for our customers' cost of capital in those figures, no.

Transcript Volume 2, Page 141, line 2

107. AMPCO submits that Hydro One's analysis of the costs and benefits should consider the full impact on ratepayers. If such a full cost accounting approach had been undertaken that included the cost of borrowing for customers as well as for Hydro One, AMPCO believes the CWIP in rate base proposal would show a higher total cost to society than the current mechanism. Many of AMPCO's members have

experienced financial decline over the last few years during the economic recession in Ontario and additional borrowing at this time places additional burden on these firms as they work towards recovery.

108. Hydro One reduced its capital budget request for 2011 by $111 million and $256 million for 2012 from what was originally going to be filed.

Undertaking J2.2

109. AMPCO asked under cross examination if the witness Mr. Struthers would agree that because of the reduction in proposed capital spending, there may be less of a need for CWIP on Bruce to Milton. Mr. Struthers responded "I agree with you from the point of view of our ability to go out and borrow, because those items won't be in rate base, then I won't have to borrow for those items, yes…"

Transcript Volume 7, Page 23, line 16

110. AMPCO submits that Hydro One's borrowing costs have been reduced as a result of the reduced capital budget, thereby reducing the need for a cash advance from ratepayers for the Bruce to Milton project under the CWIP in rate base proposal.

111. Overall, AMPCO submits that the benefits of accelerated recovery of CWIP in rate base may not be necessary and are overstated by Hydro One.

The Overall Cost of the Project in Absolute Terms

112. Hydro One calculates that the overall cost of the project using accelerated cost recovery of CWIP is $695 million compared to $762.9 million under the standard approach using AFUDC.

Board Staff Interrogatory Exhibit I, Tab 1, Schedule 122, Page 1

113. These figures change as a result of modifying the AFUDC rates which demonstrates the model/calculation is sensitive to the AFUDC rates used.

Undertakings J6.8 and J6.9

114. AMPCO submits, therefore, that the overall costs of the project as presented by Hydro One may be overstated.

The Cost of the Project in Proportion to the Current Rate Base of the Utility

115. The pre-filed evidence says "The $753 million project cost equals 10% of Hydro One's currently approved 2010 rate base of $7,636 million."

Exhibit A, Tab 11, schedule 5, Page 6, line 24

116. AMPCO submits that costs of this magnitude, as a percentage of rate base, do not create unique risks or challenges sufficient for Hydro One to justify an alternative cost recovery mechanism.

117. The Risks or Particular Challenges Associated with Completion of the Project
In the pre-filed evidence Hydro One says the accelerated cost recovery mechanism will help mitigate the risks of the Bruce to Milton project and has indicated the primary risk is further delays in project completion and that Hydro One is still waiting for some approvals.

Exhibit A, Tab 11, Schedule 5, Page 5

118. When asked about the status of any outstanding regulatory, environmental or other approvals, Hydro One responded that two approvals are outstanding: A Permit to cross the Niagara Escarpment (Hydro One is awaiting a decision) and Authority to expropriate interests in land (hearing contemplated fall 2010). Hydro One also stated that there are a number of standard environmental approvals that are progressing in the normal manner.

Board Staff Interrogatory Exhibit I, Tab 1, Schedule 121, Part a

119. The pre-filed evidence indicates that other project schedule risks include:

- weather delays
- 3rd party interventions
- unforeseen construction delays such as poor or contaminated soil conditions or site drainage issues.

Exhibit A, Tab 11, Schedule 5, Page 6

120. When asked by Board Staff if Hydro One has encountered any of the above risks, Hydro One responded "To date, there have been no delays of this nature."

Board Staff Interrogatory Exhibit I, Tab 1, Schedule 121, Part c

121. During cross examination, AMPCO asked for confirmation that the project is successfully tracking the project schedule and that Hydro One anticipates meeting the December 31, 2010 in-service date and the witness Mr. Gregg indicated, "That is correct".

Transcript Volume 2, Page 79, line 1

122. Hydro One has entered into historic agreements with two First Nations communities and the Metis Nation of Ontario (MNO) that will facilitate their continued involvement in the regulatory process and ultimate success of the project.

Exhibit A, Tab 9, Schedule 1, Letter from the Chair, Hydro One Annual Report 2008

123. During AMPCO's cross-examination regarding risks, the witness Mr. Gregg indicated that one of the most significant risks is ongoing First Nations' consultation risk.

Transcript Volume 2, Page 76, line 7

124. Hydro One has already experienced a one year delay due to approval delays so these risks have existed but given that Hydro One anticipates meeting the December 31, 2012 in-service date it would seem that Hydro One plans to successfully manage these risks moving forward.

125. Hydro One says "One has to look no further than the Niagara Reinforcement Project (NRP) for a real world example of problems that can be encountered in Ontario."

Exhibit A, Tab 11, Schedule 5, Page 6

126. As noted in the EB-2006-0501 Decision, the NRP is fundamentally different than other projects "in that it is substantially complete but work has been halted because of events outside of Hydro One's control."

Exhibit K2.5: Decision With Reasons for Hydro One Networks, EB-2006-0501,
Dated August 16, 2007, Page 53

127. In this Decision, the Board agreed that special regulatory treatment for the NRP because a recognizable risk has materialized out of the land claim dispute in Caledonia, the resolution of which is beyond the control of Hydro One.

Exhibit K2.5: Decision With Reasons for Hydro One Networks, EB-2006-0501,
Dated August 16, 2007, Page 63

128. Hydro One requested special regulatory treatment for the Bruce project as well during this proceeding and the Board decided "that a departure from conventional regulatory treatment for the Bruce project was not justified."

Exhibit K2.5: Decision With Reasons for Hydro One Networks, EB-2006-0501,
Dated August 16, 2007, Page 60

129. AMPCO submits that the risks identified by Hydro One for the Bruce to Milton project during the test period are typical of a multi-year capital intensive transmission project and do not represent extraordinary or unique risks and

challenges that warrant the alternative cost recovery mechanism requested. The risks for this project are consistent with the risks identified as part of the Section 92 application, where difficulty financing the project and the need for CWIP in rate base was not identified. Hydro One should not be compensated now for risks that may or may not materialize. Hydro One's evidence does not suggest that these risks will materialize and result in delays in completing the project.

130. For this project, AMPCO submits that conventional mechanisms are sufficient to address the investment risk. In the unlikely event that a special circumstance arose that clearly put the project at risk of completion, Hydro One could apply to the Board for relief under the conventional regulatory treatment.

The Reasons Given for Not Relying on Conventional Cost Recovery Mechanisms

131. The Board has traditionally held that a utility may earn a return only on an asset that is used and useful. The Board's approach in its Report states that conventional mechanisms remain appropriate and "in most instances conventional mechanisms will likely be sufficient to address investment risk."

Exhibit K2.3, Page 10:
EB-2009-0152 Report of the Board, "The Regulatory Treatment of Infrastructure Investment in connection with the Rate-regulated activities of Distributers and Transmitters in Ontario."

132. The evidence does not show that Hydro One will have difficulty financing the project under conventional mechanisms. Bond rating agencies have maintained positive ratings without identifying a need for special treatment for this project.

133. Hydro One's position is that CWIP in rate base provides the greatest overall benefit to ratepayers and provides risk mitigation against schedule delay.

134. AMPCO submits that the ratepayer benefits are overstated and exceptional risk circumstances do not exist for this project. AMPCO's position is that conventional

mechanisms remain appropriate and are sufficient to address investment risk on the Bruce to Milton project.

Whether the Utility is Otherwise Obligated to Undertake the Project

135. The Bruce to Milton project is not a *new* Green Energy Act-related investment. The project has OEB approval in a Section 92 application (2009). As indicated in the Investment Summary Document (ISD) for this project, Hydro One states under project need that the project is non-discretionary and that the project is required to satisfy the recommendation outlined by the OPA to accommodate new generation.

Exhibit D2, Tab 2, Schedule 3, Page 41, ISD D1

136. Hydro One did not apply for Accelerated cost recovery of CWIP as part of the Section 92 application in EB-2007-0050. Under cross-examination, the Panel One witness (Mr. Gregg) stated "the reason we are proposing this, partially because it is a tool that is now available to us through EB-2009-0150."

Transcript Volume 2, page 73, line 4

137. Hydro One applied for special regulatory treatment for this project in 2006. In the Board's Decision (EB-2006-0501), the Board found that a departure from conventional regulatory treatment for the Bruce project was not justified.

Exhibit K2.5: Decision With Reasons for Hydro One Networks, EB-2006-0501,
Dated August 16, 2007, Page 60

138. AMPCO does not believe this project is the "case" the Board had in mind in its description of qualifying investments under section 3.2.1. of the Board's Report.

Exhibit K2.3, Pages 12 to 14:
EB-2009-0152 Report of the Board, "The Regulatory Treatment of Infrastructure Investment in connection with the Rate-regulated activities of Distributers and Transmitters in Ontario."

139. AMPCO submits that Hydro One does not require the additional flexibility provided by alternative cost recovery mechanisms as an incentive in the traditional sense to make this infrastructure investment. Hydro One has committed to undertake the project and plans to complete the project with or without accelerated cost recovery of CWIP.

AMPCO Request

140. AMPCO submits that Hydro One fails to satisfy the seven factors which would justify a departure from conventional regulatory mechanisms.

141. AMPCO submits that the proposed treatment (CWIP in rate base) for the Bruce to Milton project should be rejected by the Board.

142. Without CWIP in rate base, the rate increase would be reduced by 3.5% to 12.2 % in 2011 compared to from the 15.7% originally filed. In 2012, the rate increase would be 11.6%, an increase of 1.8% from the 9.8% originally filed.

Undertaking J7.1

143. Hydro One attributes the Bruce to Milton project and the increase in cost of capital as major factors contributing to the transmission rate increases during the test period. AMPCO asked Hydro One during cross examination if they considered lowering their request for return on equity in response to their request for CWIP and the response from the witness Mr. Gregg was "No. We have not."

Transcript Volume 2, Page 72, line 4

144. Electricity rates are forecast to increase moving forward resulting in potentially significant bill impacts on customers. In the event the Board approves CWIP in rate base for the Bruce to Milton project, the Board should give consideration to

lowering Hydro One's return on equity to align with Hydro One's reduced risk profile, thereby reducing the overall impact on customers in this proceeding.

C. 9.1 Are the OM&A and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

Overview of Hydro One's Green Energy Plan

145. Hydro One filed a five year Transmission Green Energy Plan as part of its application on May 19, 2010 based on the September 21, 2009 letter from Minister Smitherman that included 20 Schedule A transmission projects, five categories of Schedule B projects to facilitate distributed generation and target in-service dates for each project.

Exhibit A, Tab 11, Schedule 4, Appendix A

146. The proposed expenditures related to the Green Energy Plan are summarized in Table 1.

Table 1: Proposed Transmission Green Energy Plan Expenditures

	2011 OM&A*	**2012 OM&A***	Total OM&A (before 2011 and after 2012)	**2011 Capital**	**2012 Capital**	Total Capital (2010-2020)
Schedule A Projects (A-11-4, Page 46, T 5)	**$35.70**	**$46.7**	$159.5	**$ 4.5**	**$ 22.6**	$6937.1
Schedule B Projects (I-1-107, Page 2)				**$120.8**	**$168.3**	$ 837
Other cap projects <$3 M (I-3-12 Page 2)				**$ 1.4**	**$ 7.3**	
TOTAL (2011 & 2012)	**$35.70**	**$46.7**		**$126.7**	**$198.2**	$7,774.1

*OM&A spending to be recorded in deferral account: "IPSP and Other Preliminary Planning Costs Account".(No impact on revenue requirement in test years)

147. In a letter dated May 7, 2010 to the OPA, Minister Duguid requested that the OPA develop and submit, by June 11, 2010, a revised transmission expansion plan to update the September 2009 direction to Hydro One, that the revised plan was to consider the sequencing necessary to meet the needs of the Feed-In-Tariff ("FIT") program and the Korean Consortium.

Board Staff Interrogatory, Exhibit I, Tab 1, Schedule 98, Attachment 1

148. AMPCO does not believe that the OPA has yet provided its advice to the Minister. On May 5, 2010, the Minister wrote Hydro One to request that Hydro One carefully reassess the contents of its transmission application and identify cost saving opportunities.

Board Staff Interrogatory, Exhibit I, Tab 1, Schedule 98, Attachment 2

Schedule A Projects - Development OM&A

149. Hydro One's Green Energy Plan includes development work in the test years for 17 of the 20 Schedule A projects, $35.7 million in 2011, and $46.7 million in 2012 for a total of $82.4 million. Three projects from the Minister's letter (#6, #19 & #20) are not included as the time frame is too long and development work is not required in the test years. Hydro One is proposing that the development costs for the remaining Schedule A projects be included in a deferral account with no impact on revenue requirement in the test years.

150. Hydro One grouped the Schedule A projects into three categories: (1) Projects where development work is underway; (2) Projects where development work will

begin once the OPA confirms the project need; and (3) Projects where the development work is not planned in the test years.

Exhibit A, Tab 11, Schedule 4, Page 9, Table 1

151. Hydro One began work on the priority projects in the first category in order to meet the target in-service dates identified in the Minister's letter. Development costs for work performed in 2010 on these projects is $2.7 million. An additional $1.9 million was performed in 2009 and recovery of this amount is requested in this application.

Undertaking J6.1

152. In recognition of the status of the OPA's advice and Minister Duguid's May 5, 2010 letter, Hydro One began to suspend development work on all Schedule A projects pending the results of the OPA's FIT analysis.

Board Staff Interrogatory, Exhibit I, Tab 1, Schedule 98

153. Recovery of the funds spent on projects in 2010 up to the work stoppage will be placed in a variance account to be recovered in Hydro One's next rates case.

OPA FIT Results

154. Hydro One's Green Energy Plan includes transmission investments to integrate up to 10,000 MW and beyond of potential renewable generation. As of April 8, 2010 the OPA has awarded 2,421 MW of contracts to 184 FIT applicants whose projects passed the Transmission Availability Test (TAT).

Board Staff Interrogatory, Exhibit I, Tab 1, Schedule 100, Part b

155. Connection work associated with the FIT applications that have received contracts from the OPA is proceeding.

Transcript Volume 2, Page 42, line 2

156. Additional FIT applications that did not pass the TAT are awaiting an Economic Connection Test (ECT). These applications total approximately 6,500 MW.

Transcript Volume 2, page 45, line 9

157. The OPA's ECT process is expected to begin in the fall of 2010 and the first ECT assessment cycle is expected to be completed in the spring of 2011.

Board Staff Interrogatory Exhibit I, Tab 1, Schedule 105, Parts a & b

158. During cross examination by Board Staff, Hydro One agreed that the ECT did not begin as scheduled and Hydro One did not have specific information on when it will start.

Transcript Volume 3, Page 170, line 13

159. The OPA is awaiting the results of the ECT analysis before providing its advice to the Minister. Results of the ECT process will signal where additional transmission reinforcement is required to connect the additional projects. Following this first ECT assessment, Hydro One expects to consult with the OPA to identify those projects that should proceed with development work. From the evidence, the earliest this activity will take place appears to be late Q2/Q3 2011.

160. During cross examination, AMPCO asked if the priorities are still the same with respect to the Schedule A projects and the witness Mr. Gregg replied, "We do not know at this point."

Transcript Volume 2, Page 49

161. And when asked by AMPCO if not all of the projects will go ahead, Mr. Gregg confirmed"..that could be correct."

Transcript Volume 2, page 53

162. Based on the ECT results, Hydro One and the OPA may conclude that the project need has changed and development work on some projects may not go ahead.

163. During AMPCO's cross-examination, Hydro One agreed that the decision to suspend work would affect the proposed spending and the spending would be less on specific projects.

Transcript Volume 2, Page 35

164. Hydro One anticipates, however, that there will be development work in the test years on transmission projects to enable connection of green generation to the grid. When asked if the level of OM&A spending will be the same in the test years as in the Plan, Hydro One responded "generally, yes."

Transcript Volume 2, Page 55

AMPCO Position

165. Regardless of the deferral account mechanism proposed, spending on Schedule A projects during the test period will be recovered from ratepayers at a future rate proceeding. AMPCO does not agree that the level of OM&A spending during the test years will be at the level forecasted in the Plan. Although there has been significant take-up in the FIT program, since Hydro One does not know what the final results of the ECT analysis are and where the development work should be undertaken, AMPCO does not concur that the forecasted spending is accurate. Furthermore, the $4.6 M spent to date on Schedule A projects ($1.9 M in 2009 and $2.7 M in 2010) may not have been directed to the right priority projects.

166. In Hydro One's closing argument on October 7, 2010, Hydro One's counsel stated the Board is being asked to approve the Green Energy Plan "conceptually" (which AMPCO interprets in part as a request for agreement on the Schedule A projects

and level of spending proposed). Hydro One also anticipates filing an updated five-year green energy plan at its next transmission rate filing.

Transcript Volume 11, Pages 5 to 8

167. AMPCO submits that given the uncertainty around the timing and results of the ECT analysis; the pending advice from the OPA on the projects that require development work; and the potential change in projects and costs that will flow from this analysis, the Board should not "conceptually" approve Hydro One's Green Energy Plan.

168. Instead, AMPCO recommends that pre-planning work on Schedule A projects not continue and that this part of the proceeding be kept open until Hydro One submits an updated Green Energy Plan based on new direction from the Minister in order to provide the Board with sufficient evidence to approve specifically the spending levels and priority Schedule A projects. This will ensure that the OM&A spending during the test period is directed to the right priority projects, for recovery at a future rate proceeding.

169. Alternatively, if the Board is not in favour of keeping this proceeding open, the Board could ask Hydro One to reapply with an updated Green Energy Plan for approval of Schedule A projects once Hydro One has received updated information from the OPA and instructions from the Minister.

Schedule A Projects - Capital

170. Capital expenditures of $4.5 million in 2011 and $22.6 million in 2012 are included in the Development Capital Budget for two Schedule A projects (Algoma to Sudbury and Northwest Transmission and) with target in-service dates of 2015 and 2014, respectively. The capital expenditures are required to purchase long lead time materials and equipment in advance of completing the development activities.

Board Staff Interrogatory Exhibit I, Tab 1, Schedule 119, Part b

171. The development work on these projects has been suspended. Hydro One has indicated that until further information is provided by the OPA, there is no recent assessment of the date the project is needed.

Board Staff Interrogatory Exhibit I, Tab 1, schedule 115, Part a

AMPCO Position

172. AMPCO agrees with Board Staff that there are no guarantees these two projects will proceed and as a result the capital costs associated with these two Schedule A projects should be removed from the capital budget.

Schedule B Projects - Capital

173. During Hydro One's closing argument on October 7, 2010, the Board was asked to approve the following regarding Schedule B projects:

- Approval of capital budget over the test years: $126.7 in 2011 and $198.2 2012. (Includes two Schedule A projects: Northwest Transmission Reinforcement and Algoma to Sudbury discussed above)
- In-service capital additions of $11.4 million in 2011 and $198.9 million in 2012; rate base additions of $9.6 million in 2011 and $114.8 million in 2012 related to work on the six Schedule B projects that are forecast to come into service in the test years:
    - Hearn TS project D11;
    - Leaside TS project D12;
    - In-Line Circuit Breakers projects D37 & D38; and
    - Protection and Control for Enablement of Distribution Connected Generation projects D43 & D44.

- The impact on the revenue requirement of these project additions to rate base is $0.9 million in 2011 and $10.3 million in 2012.

Transcript Volume 11, pages 6 to 8

AMPCO Position

174. AMPCO has concerns about including the In-Line Circuit Breakers (D37 & D38) in rate base as the evidence indicates that specific locations for projects D37 and D38 are not known and the location and need will be determined through connection assessments of FIT projects and the ECT process for new transmission facilities.

Board Staff Interrogatory Exhibit I, Tab 1, Schedule 117, Part a

175. During the hearing, Hydro One indicated that at least one In-line Circuit Breaker will be needed in 2012, another one has been confirmed in 2013 and a second one will likely be required by 2012.

Transcript Volume 3, Page 163

176. Given the uncertainty around the timing of the ECT process, AMPCO submits that Hydro One has not adequately demonstrated the need and timing for two In-line Circuit Breakers to be in-service in 2012. Preliminary cost estimates show $13.4 million in 2011 and $6.9 million in 2012 for each Breaker for a total of $20.3 M over the test period.

Exhibit D1, Tab 3, Schedule 3, Attachment A, Page 8

177. AMPCO submits that the need for only one In-line Circuit Breaker in 2012 has been established and the costs for one Breaker, not two, should be included in rate base.

178. Should the Board agree with AMPCO that the proceeding be kept open pending an updated Green Energy Plan, new evidence on the location and need for a second In-Line Circuit Breaker could be submitted for the Board's consideration. Under this

proposal, the Board may decide to declare the 2011/2012 rates interim in order to include the rate impact of this project should the Board approve the project.

Category 3 Projects

179. The Green Energy Plan capital budget also includes the following projects that are not forecast to come into service in the test years but are category 3 projects that have significant spending within the test years: (References regarding location and timing are included where applicable)

- **Manby TS – Station Upgrade for Short Circuit Capability** (D13)
- **One Static Var Compensator (SVC) project** (D36)

  The locations of the SVC installations are not known at this time. IESO working group will look to identify the location, size and timing for SVC installations.

  Board Staff Interrogatory Exhibit I, Tab 1, Schedule 116, Part a

- **Two enabling TS projects** (D32 and D33)

  The locations are not known. Hydro One will rely on the OPA's ECT process to establish the locations and also the need for additional enabler stations.

  Board Staff Interrogatory Exhibit I, Tab 1, Schedule 114, Parts a and c

  During the hearing, Hydro One reconfirmed that the locations are not yet known.

  Transcript Volume 3, Page 166

  "Given the timing right now that we understand of the ECT process, it is quite likely that an enabler will not be able to be built by that time.

  Transcript Volume 3, Page 167

- **Four In-line Circuit Breakers projects** (D39, D40, D41 & D42)
  The required size and locations of such facilities will depend on the FIT applications and the outcome of the OPA's ECT process.

Board Staff Interrogatory Exhibit I, Tab 1, Schedule 110, Page 4

180. For category 3 projects, Hydro One is seeking guidance from the Board on the appropriateness of the need, the proposed solution, and the recoverability of the project cost.

Exhibit D1, Tab 3, Schedule 3, Page 11

181. As noted above, the specific locations of the SVCs, enabling TSs and In-line Circuit breakers are not known at this time. AMPCO agrees with Board staff that the need for the projects (with the exception of the Manby TS upgrade) has not been confirmed by the OPA.

AMPCO Position

182. AMPCO submits that given the uncertainty around the specific project details regarding location and, in some cases, need and project cost estimates, there is a risk that these investments will not occur (or may occur but not the responsibility of Hydro One) and it is pre-mature for the Board to provide guidance or pre-approval for these projects in this proceeding.

183. Should the Board agree with AMPCO to keep this proceeding open to allow Hydro One to submit an updated and more specific Green Energy Plan, additional evidence regarding these projects could be included for the Board's consideration.

Partnerships

184. The September 21, 2010 letter from Minister Smitherman says:

"4. Given the magnitude of work required to complete the Transmission Projects (Hydro One is to complete the following activities):

a. Identify the commercially reasonable opportunities for entering into partnership arrangements with qualified third parties/partners for the execution of Projects:
b. Work with shareholder to identify commercially reasonable criteria that will be used to select qualified third parties/partners;
c. Use best efforts to enter into these commercially reasonable arrangements; and
d. Identify projects as appropriate where the planning, development and implementation of the project would be better accomplished by a qualified third party other than Hydro One".

Exhibit A, Tab 11, Schedule 4, Appendix A, Page 2

185. The Board's Guideline G-2010-0059 indicates "the Board believes this guideline will:

- allow transmitters to move ahead on development work in a timely manner;
- encourage new entrants to transmission in Ontario bringing additional resources for project development; and
- support competition in transmission in Ontario to drive economic efficiency for the benefit of ratepayers."

Exhibit K2.4: G-2010-0059, Board Policy Framework for Transmission Project Development Plans, Page 1

186. The Board's Guideline also states:

"When the Board receives the results of an Economic Connection Test (ECT) from the OPA, the Board will issue a notice of hearing to designate development of any enabler facility and network expansions identified in the ECT report.

In the notice the Board will invite all licensed transmitters to submit plans in the form mandated by filing requirements. Only the transmitter that is successful in being designated will be able to recover its costs of preparing a plan.

If no plans are submitted for a particular project, the Board will require the incumbent transmitter to file a plan under section 70 (2.1) of the Ontario Energy Board ACT, 1998."

Exhibit K2.4: G-2010-0059, Board Policy Framework for Transmission Project Development Plans, Filing Requirements, Page 2

187. In response to an interrogatory asking if Hydro One had considered which of the specific projects would be better developed and implemented by a party other than Hydro One and if so which ones and if not, why not? Hydro one responded that it has not determined which if any of the projects would be better developed and implemented by a qualified third party at this time.

Great Lakes Power Transmission Interrogatory Exhibit I, Tab 8, Schedule 1

188. AMPCO asked Hydro One why it has not done this. Hydro One responded that early development work is required to better understand the intricacies of such a project to better judge what may be done by others and Hydro One has not gotten to the stage to make that determination.

Transcript Volume 2, Page 56

189. Hydro One's Green Energy Plan shows Hydro One's plans to undertake development work on all 20 Schedule A projects identified in the September 21, 2009 letter from the Minister totalling $159.5 million.

Exhibit C1, Tab 2, Schedule 4, Page 10, Table 1

AMPCO Position

190. AMPCO understands that as a result of the September 21, 2009 letter, Hydro One began development work on a list of priority projects in order to meet target in-service dates proposed in the letter. Nowhere in Hydro One's Transmission Green Energy Plan, however, is there the acknowledgement that development work on

some of the Schedule A projects work may be better done by other parties or that Hydro One intends to identify partnership opportunities.

191. AMPCO submits that undertaking the development work on all of the projects has two potential outcomes for Hydro One. On one hand, it gives Hydro One an advantage over other transmitters during a competitive process. On the other hand, if Hydro One is unsuccessful in a competitive process, Hydro One is at risk of not recovering the development costs associated with the project.

192. For mandated transmission projects where the Board is inviting licensed transmitters to submit plans and Hydro One has undertaken development work, it is AMPCO's position that the Board should require Hydro One to make the work publicly available during the competitive process as well as useful to another transmitter should Hydro One not be awarded the contract.

Conclusion

193. AMPCO requests the following of the Board with respect to Hydro One's Green Energy Plan:

- the Board should not "conceptually" approve Hydro One's Green Energy Plan;
- in lieu, the pre-planning work on Schedule A projects should not continue and the approval of the Green Energy Plan should remain open pending new advice from the OPA and direction from the Minister;
- in the alternative, Hydro One should be required to re-apply for a new Green Energy Plan approval after advice from the OPA and direction from the Minister is received;
- capital costs for the Algoma to Sudbury and Northwest Transmission projects should be removed from the Hydro One budget;

- the costs of only one In-Line Circuit Breaker should be included in the rate base;
- given the present uncertainty, it is premature for the Board to provide guidance or pre-approval for these projects in this proceeding;
- development work on all projects for which Hydro One receives cost approval by the Board and for which the Board has invited licence transmitters to submit plans should be made publicly available during the competitive bidding process.

D. Issue 4.2 Are the proposed 2011 and 2012 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

194. Hydro One has proposed a large capital budget for 2011 and one almost as large for 2012. Since the approved capital budget drives a significant portion of the revenue requirement, it is prudent to ask whether in fact the money requested will actually be spent, or whether customers are being asked to pay rates higher than necessary, had rates been determined only on the basis of what actually was spent and/or went into service.

195. Hydro One's Response to an AMPCO interrogatory on capital spending is set out below:

Capital Costs ($ in Million)														
Description	2006 BA*	2006 Actual	2006 Var*	2007 BA	2007 Actual	2007 Var	2008 BA	2008 Actual	2008 Var	2009 Actual	2009 BA	2010 Bridge	2011 Test	2012 Test
Sustaining	N/A	178.5	N/A	288.1	210	(78.1)	295.6	280.4	(15.2)	300.0	279.9	308.3	424.0	443.4
Development	N/A	179.4	N/A	318.8	272.6	(46.2)	415.6	310.9	(104.7)	516.2	545.9	537.9	617.2	456.8
Operations	N/A	9.4	N/A	20.1	4.7	(15.4)	20.4	23.1	2.7	20.0	18.2	10.1	44.3	57.4
Shared Services Capital	N/A	34.1	N/A	84.6	72.2	(12.5)	42.8	89.8	47.0	81.5	92.4	73.6	66.3	50.6
TOTAL	N/A	401.6	N/A	711.6	559.5	(152.1)	774.4	704.2	(70.2)	917.8	936.5	930.0	1151.8	1008.3

* No Board Approved amounts for 2006

Exhibit I, Tab 9, Schedule 22

196. Capital budgets for 2007 and 2008 were proposed and approved in the 2007 hearing EB-2006-0501.A large program increase (for the time) was being proposed by Hydro One and, therefore, it was examined by intervenors. Below is the response Hydro One provided to an interrogatory by Board staff on the matter of how it would deal with such an aggressive building program:

> "Hydro One will deal with this increased building program though utilizing a broad range of resourcing strategies, contracting for necessary materials, and continuing to streamline processes, both internal and external, including facilitating the increased use of external competitively procured services to augment internal engineering and construction expertise."
>
> EB-2006-0501 Exhibit J, Tab 1, Schedule 70

197. Hydro One went on to describe in more detail the strategies being developed to implement such a large capital program. Nonetheless, Hydro One went on to under-accomplish its 2007 and 2008 programs by a combined total of over $220M.

198. In EB-2008-0272, Board staff raised the matter again:

> MR. MILLAR: And at least in the past -- I know we've discussed this, and we'll discuss it a little bit more -- you've had some trouble spending your entire approved amount. Is that fair to say?
> MR. GRAHAM: That would be fair to say, particularly for 7 and 8, yes.
> MR. MILLAR: So you discuss some of these challenges in your pre-filed evidence. Maybe I would ask you to turn to Exhibit A, tab 14, schedule 7. Page 6 of that exhibit.
> MR. GRAHAM: Perhaps as context, Mr. Millar, I could just note that while it is true that we did have under-expenditures in 7 and 8, and there are reasons for that given in this filing, I would note that the spending rate at the -- particularly in the latter part of '08 was at a rate which would -- I know it is simplistic to say this, but if you take the last six months of expenditures, which were approximately 444 million, that is an annual rate of $890 million.

Transcript Volume 1, Page 187

199. For this hearing, Hydro One's projected capital expenditures versus Board approved levels for 2010 were also provided:

Table 3
2010 Board Approved versus 2010 Projected Capital Expenditures

Capital Category	**2010 Board Approved** ($ million)	**2010 Bridge Year** ($ million)	**Variance** ($ million)
Sustaining	321.6	308.3	(13.3)
Development	642.3	537.9	(104.4)
Operations	28.9	10.1	(18.8)
Shared Services	64.9	73.6	8.7
Total	**1,057.6**	**930.0**	**(127.6)**

Exhibit D1, Tab 3, Schedule 1, Page 5

200. AMPCO examined this pattern of repeated shortfalls with the Hydro One witness:

> MR. McQUEEN: I would agree that we make reference, as prudent managers would, to the challenges that we face in running our business and the actions that we are putting in place in order to address those challenges. And I think our record would show that we have been quite successful over the last number of years in increasing our ability to deliver more and more work that is put before us.

Transcript, Volume 2, Page 67

201. Historically, the record shows that issues have always arisen which interfere with Hydro One's ability to put in place the projects which are planned in their capital budget. As the number and size of programs planned increases, the impediments to their implementation can also be expected to increase. Customers should only be required to pay for what actually happens and not for plans that were approved but not fully executed.

202. Compared to previous years, the customer interest is increased by the twin realities that rate base is projected to grow much faster than in the past and that a higher ROE also impacts rates. For 2011, the proposed Hydro One increase in rate base will add $115.3M to revenue requirement, of which $69.8M will be needed even if CWIP is rejected for the Bruce to Milton project. This does not include the secondary impact of associated increases in borrowing. Even a 10% under expenditure by Hydro One would be material for customers. The average under-accomplishment for the past five years has been slightly over 10%.

Exhibit E1, Tab 1, Schedule 1, Table 3

203. Given the variability in the record of under-expenditure, it is difficult to predict by how much, Hydro One will underspend approved levels in 2011 and 2012. Thus, AMPCO believes it would be imprudent to formulaically discount Hydro One's capital budget based on past performance.

204. At the same time, the need to protect the customer interest suggests that the expenditure risk be mitigated in some way.

Conclusion

205. AMPCO submits, therefore, that to mitigate customer risk while also allowing Hydro One the ability to pursue an approved capital program Hydro One should be required to establish a symmetrical variance account to capture the reduced revenue requirements associated with under-expenditures on capital programs. This would have the secondary benefit of incenting more realistic forecasting of capital requirements.

E. Issue 6.1 Are the proposed amounts, disposition and continuance of Hydro One’s existing Deferral Variance accounts appropriate?

206. Hydro One proposes to discontinue the deferral account for Export Transmission Service Revenues, suggesting that the revenue uncertainty had reduced and the account is no longer needed.

Transcript Volume 7, Page 119

207. In EB-2008-0272, intervenors and Board staff submitted that the forecast at the time was too low and should either be subject to a variance account or increased. The Board chose to establish a variance account.

> The Board concludes that Hydro One has an incentive to be conservative in its forecast so as to protect itself from under-recovery. While the Board believes that it is appropriate for customers to get the full benefit of these revenues, the Board also believes that it would be inappropriate to expose Hydro One to the risk of an overly generous revenue forecast.
> The Board concludes that it is appropriate to establish a variance account to capture any difference between the forecast and actual revenues and that the account should be symmetrical

EB-2008-0272 Decision With Reasons, Page 12

208. The Table below illustrates the forecast accuracy on export revenue to date

Exhibit I, Tab 9, Schedule 1, Page 3

Year	Forecast ETS Revenue ($M)	Actual ETS revenue based on IESO invoice ($M)	Variance of forecast as percentage of actual
2005	5.8	12.0	-51.6%
2006	8.6	13.3	-35.1%
2007	12.0	14.1	-15.1%
2008	12.0	24.6	-51.2%
2009	12.0	16.8	-28.6%
Mean			-36.3%

209. There are three points to be made in this table. First, the forecast error for export revenue has been consistently large. Second, export revenues have been consistently under-forecast, leading to more revenue than forecast. Third, export

revenues have been generally growing over time, with 2009 levels exceeded only by 2008.

210. Against this background, Hydro One has forecast 2011 and 2012 revenues at $10.1 and $10.2M respectively, each of which is significantly lower than any in the period 2001-2009.

211. AMPCO submits that the evidence supports that the forecast for export revenue remains unrealistically low and that the variance account should be retained.

F. Issue 1.1 Has Hydro One responded appropriately to all relevant Board directions from previous proceedings?

212. AMPCO believes that the ETS tariff, on an interim basis, should be changed so that during peak hours it is $5.00/MW hr and $0/MW hr in non-peak hours to represent a first step in removing the subsidy for electricity exports in Ontario.

The Record

213. The $1.00/MWhr ETS tariff is derived from the Board's acceptance of a settlement agreement between Hydro One and intervenors in EB-2006-0501.

214. This agreement included the following:

> The parties have agreed that the status quo ETS tariff of $1/MWh should be maintained for the time being, but that the IESO should now be identified as the entity responsible to pursue and negotiate, with neighbouring jurisdictions, acceptable reciprocal arrangements with the intention to eliminate the ETS tariff, and study the appropriate ETS tariff, including those options identified in H1/T5/S1. The IESO will seek input from market participants and interested intervenors in this proceeding and keep the parties informed of the progress of negotiations and the study. It is agreed that the IESO will make its report available to the Board upon completion which will be no later than June 1, 2009 with the results of

> reciprocal arrangement negotiations and the study including recommendations for an appropriate ETS tariff. Hydro One Networks Inc. remains responsible for seeking changes to its approved transmission revenues and rates and will do so as part of the 2010 transmission rate-resetting process period, following the publishing of the study.

EB-2006-0501 Decision with Reasons, August 16, 2007, Appendix 2, Page 17

215. As of this date the ETS tariff remains the same.

Exhibit H1, Tab 5, Schedule 2, Page 4, lines 11-15

Role of Hydro One

216. The ETS tariff is a transmission tariff and a significant source of revenue for Hydro One. For 2011 and 2012, the forecast is slightly over $10M for each year, at the $1.00/MWhr rate. This corresponds to a traffic volume of over 10TWhr on the grid, a volume equal to about 7% of the roughly 145 TWhrs in annual Ontario energy demand supplied by the grid. This 7% of traffic provides less than 1% of Hydro One's revenue requirement.

Exhibit H1, Tab 5, Schedule 1, Section 2.0
Transcript Volume 9, page 35, lines 5-6

217. It does not appear from the evidence that Hydro One has provided assistance to the IESO in recommending an appropriate ETS tarriff; Hydro One left the IESO to seek extensions for the study, even though it was Hydro One's ultimate responsibility to see that the work was completed; they provided no apparent guidance on the principles of rate design for the IESO to consider in its recommendation.

Role of the IESO

218. The IESO is the transmission system operator and the wholesale market administrator. This role places an emphasis on maintaining the reliability of the grid.

Electricity Act, 1998, Part II (5)

219. The IESO has no role in the design or setting of rates for utility services and is, therefore, not knowledgeable in areas that impact rate design, such as cost causality, fairness, etc. Its own witness (Mr. Finkbeiner) stated this directly when asked whether an average cost approach would be a sound rate setting principle:

> MR. FINKBEINER: I am not aware whether it is or isn't. It was taken from earlier Hydro One proceedings with that type of definition.
> I am not an expert in rate design. I don't know what would be included in that definition, or without".

Transcript Volume 9, Page 40, lines 23-27

220. The IESO is not charged with rate making and design responsibilities and should not be expected to be expert in the area.

221. It was equally reasonable to expect that the IESO would view the ETS tariff issue through its lens as a system operator.

222. The IESO views the ETS tariff not as a fee for a service that has a cost, but as a system management tool:

> MR. RODGER: So I take it that from your evidence, both prefiled and today, is that the reason why IESO senior management decided that notwithstanding the work that was done and the work that Charles River has done, that the prudent course at least at this time was to stay with the status quo, because this is one of the tools that the IESO can use to manage the situation in Ontario.
> Is that an accurate summary?
> MR. FINKBEINER: That is an accurate summary.

Transcript Volume 9, Pages 43-44

The IESO Study and Process

223. The IESO followed an accepted process in developing terms of reference for the study, except that the IESO did not provide for any stakeholder funding. This significantly limited customer involvement in the process and produced representation weighted in favour of traders and generators, since customer associations often have no significant funding for these processes other than intervenor funding.

Exhibit H1, Tab 2, Schedule 2, Attachment 1

224. Notwithstanding this limitation, the consultant, Charles River Associates, is well known in the industry and produced a credible and thorough analysis. Based on this and after consideration of stakeholder input, the IESO settled on a recommendation of Option #2, the average network rate. This was announced to stakeholders on Aug 10, 2009.

Transcript Volume 9, Page 55, lines 6-14.

225. AMPCO submits that, the recommendation communicated on August 10 was consistent with generally accepted ratemaking principles, notwithstanding the IESO's self-acknowledged limitations in this area. It was also consistent with the objectives the IESO had communicated when the stakeholder consultation was initiated, namely;

> In formulating the approach for undertaking the study and process for reviewing and recommending the appropriate ETS tariff, the IESO will rely upon parameters and evaluation principles that were discussed as part of Hydro One's transmission rate review (EB-2006-0501, Exhibit HI, Tab 5, Schedule 1, Page 7 -8). The primary focus of the IESO's effort is to consider various alternatives to the current tariff design and rate, and the likely impacts of each of these alternatives on a number of parameters that were identified as being important to stakeholders. These parameters include: export volumes, ETS

revenues, HOEP and market efficiency. Based on a review of the impacts of the current and alternative tariff design on these parameters, the IESO will propose the appropriate tariff design and rate(s) which will strike a balance between simplicity of implementation, fairness and equity, the degree to which it will promote market efficiency in the region, and consistency with rates in neighbouring jurisdictions.

Exhibit H1, Tab5, Schedule 2, Attachment 1, Page 2 of 23 of IESO stakeholder plan

The IESO Recommendation

226. Sometime after completing the open stakeholder process on August 10 and August 27, the IESO reversed its recommendation without any consultation with the stakeholder group at large.

Transcript Volume 9, Page 55, line 22-Page 56, line18

227. The reasons stated for the reversal are largely technical in nature and the stated reason at the time was a concern for the IESO's ability to cope with changing market conditions.

AMPCO's Perspective

228. AMPCO submits that the reversal by the IESO should not be accepted. After a study that took months to carefully develop in an open and transparent manner, which came to an opposite conclusion. AMPCO submits that the process by which the IESO reversed its final recommendation was flawed to a degree that the Board should reject it.

229. AMPCO accepts that surplus baseload generation and intermittent renewable resources present challenges to the management of the IESO controlled grid. These issues are likely to persist for some time, but they are hardly unique to Ontario. Especially with respect to renewables, many jurisdictions around the world have

had to deal with the problems associated with these resources. As with other jurisdictions, the IESO has several tools with which to manage these problems, through its dispatch instructions, use of generation regulation and other options.

230. AMPCO is not aware of any other jurisdiction which has subsidised exports in order to manage these issues.

231. As noted in the transcript, the effect of surplus generation is to reduce price, sometimes into negative figures. Effectively, generators who believe the cost of adjusting their output exceeds the loss they would incur on lowering their price, will lower their price to the level needed to ensure continuing operation. This situation is not unique to generators; AMPCO's members regularly make decisions on whether to accept losses on some production by paying a high price for energy or face the high cost of shutting down and restarting a complex industrial process in order to avoid high energy prices.

232. The effect of setting an ETS tariff level that reflects the actual costs they cause will be simply to adjust the pricing point for their decisions. This will not necessarily impose significant financial penalties, since most generators already enjoy the benefit of guaranteed floor prices or contracts for differences through their contracts with the OPA.

233. At bottom, the IESO is attempting to arrogate a transmission tariff for use as a technical tool to be used by itself for its own purposes.

234. The IESO does not have among its objects the protection of consumer interests.
Electricity Act, 1998, Part II

235. The Board does have the responsibility to protect the interests of consumers.

236. AMPCO respectfully submits that the board cannot accept the recommendation of the IESO in this matter, as it would fail the test of protecting customers through the setting of just and reasonable rates.

Relief Sought

237. AMPCO requests that, as an interim measure, the ETS tariff for all exports from Ontario be set at $5.00/MWhr in peak hours and $0/MWhr in non-peak hours. This treatment will be consistent in principle with AMPCO's position that network use during non-peak hours drives little marginal cost and hence should not be charged. AMPCO submits this approach follows sound rate design principles. It should also have the effect of making it easier to export surplus baseload generation during off peak hours when it is most likely to occur.