

**Title:** Stakeholder Consultation

**Preamble:** “The Consultation process in respect of Phase II matters was not designed to necessarily result in consensus among interested parties”.

**Reference:** S3 – 40

**Request:**

- (a) Please explain why the AESO’s stakeholder consultation process was not “designed” with the objective of reaching a negotiated settlement.
- (b) Is the AESO of the view that its consultation activities were successful? If so, explain why.
- (c) Please document the total duration of consultation process that the AESO undertook in regards to Phase II activities. Does that AESO believe that a consensus approach would lead to a more time consuming process? Please provide a summary of the benefits the AESO sees as resulting from the consensus approach.

**Response:**

- (a) As noted, the process was not designed to *necessarily* result in consensus. As suggested on various occasions throughout the discussions, the AESO was open to attempting to negotiate a settlement. However, based on the discussions and input received, the process did not lead to a settlement.
- (b) The AESO believes that the proposals in the Application, which were made after considerable consultation, are better than those the AESO could have made in the absence of the discussions and feedback received from stakeholders. This is due in large part to the fact that many of the comments and concerns raised by stakeholders prompted the AESO to conduct further analysis. The consultation activities also provided the opportunity for significant information sharing. The AESO considers these successes.
- (c) As noted in the second bullet point on page 1 in Section 4 of the Application, the phase II consultation extended from August 2005 to October 2006, or about 14 months. The AESO is not convinced that consensus among all parties was achievable in this instance, based on the input received, and therefore is of the view the EUB process underway now is the most efficient manner in which to arrive at the final 2007 tariff. The AESO believes both a settlement approach (if possible) and the EUB approach can be reasonable ways in which to set a tariff. As noted in (b) the AESO believes there are benefits to consultation, which would also be realized if consensus or a settlement was reached. However, benefits are also realized in the absence of a consensus or a settlement.

**Title:** POD charge benchmarking

**Preamble:** The PPGA wishes to understand if the AESO conducted a study to benchmark the use of a POD charge with other utilities in North America.

**Reference:** Alberta Transmission system, 2006 Transmission Cost Causation Update, page 47

**Request:**

- (a) Please confirm if the AESO undertook such a study.
- (b) If so, how many utilities in North America were studied?
- (c) How many of the utilities examined had POD charges?
- (d) What were the reasons supporting such a POD charge or explaining why no such charge was levied?
- (e) Please provide the details of the benchmarking studies undertaken and a copy of any reports prepared.

**Response:**

- (a-e) The AESO did not undertake such a study.

Although the AESO did not review transmission rates in other jurisdictions specifically for POD charges, the AESO is familiar with rates in some jurisdictions. The only rate that the AESO has encountered that includes a charge similar to the AESO's POD charge is the "Reseller" rate of SaskPower for transmission service to the Cities of Swift Current and Saskatoon. The Reseller rate includes specific monthly charges of \$4,230.00/month, \$5,259.00/month, and \$10,537.00/month for the three services at which the rate applies.

**Title:** POD Costs

**Preamble:** As part of the POD and contribution policy analysis, the AESO included TFO costs for 13 PODs that are less than 7.5 MWs, escalating these older sites to 2007 dollars.

**Reference:** Section 6, page 19

**Request:**

- (a) Please provide a breakdown of line and substation costs for each of the sites.
- (b) Please provide the original cost, NVB and in-service dates for these PODs.
- (c) Please indicate the total number of PODs from which the 13 PODs were selected.
- (d) Please explain how the AESO arrived at the sample 'size' utilized.

**Response:**

- (a) The cost breakdown for these PODs by substation and line categories is not available from the data.
- (b) Please see AESO response to PPGA.AESO-007 (a).
- (c) The 13 TFO data projects were selected from a total of 109 PODs.
- (d) The selected PODs were all PODs which satisfied the following three criteria:
  - Capacity was less than 7.5 MW,
  - In-service date was known, and
  - In-service date was 1987 or later.The AESO considered data for PODs more than 20 years old (about half the average service life of transformers) to be less reliable. Only 13 PODs satisfied all three criteria.

**Title:** POD Costs

**Preamble:** The AESO chose to use 7.5 MW as a breakpoint in the data analysis for the investment function and POD costs. In the AESO's stakeholder consultation seminars, the AESO used a breakpoint of 17 MW.

**Reference:** S4, PAGE 13

**Request:**

- (a) Please confirm that the breakpoint originally used was 5.0 MW
- (b) Please explain why the AESO originally selected 5.0 MW and why 7.5 MW is now used as a break point.
- (c) Please explain the basis for the 17 MW breakpoint used during the AESO's consultation process.
- (d) Please provide data and the appropriate files and calculate the following for all the various sample sizes from all 400+ PODS, for the following:
  - (i) What is the average and median DTS contract (kW)?
  - (ii) What is the average and median Transformer size?
  - (iii) If the data is organized by transformer or DTS contract size into appropriate kVA Levels, what are the modes for various DTS contract and Transformer sizes at 5, 10, 25, 40, 50+ kVA?

**Response:**

- (a) In June 2006, the AESO proposed a closed "grandfathered" rate available to any existing service with DTS contract capacity of 5 MW or less on January 1, 2006.
- (b) The 5 MW threshold for the proposed closed rate reflected the 5 MW breakpoint in the AESO 2006 tariff and the conclusion that small services represent a cost function that differs from larger services. Arguments against a closed rate convinced the AESO to further examine the cost function and develop a rate alternative which be applicable to all customers.

The additional investigation of the cost function let the AESO to adopt a minimum-intercept analysis for services for which data did not exist in the recent projects in the *Customer Contribution Study*. The smallest project in the *Customer Contribution Study* was 7.5 MW, and the AESO adopted that as the breakpoint for the interpolated cost function for small projects. This function was also validated against 13 small TFO

projects where the vintage was known, which provided linear regression coefficients similar to the interpolated cost function.

- (c) In July 2006, the AESO proposed a single rate applicable to all DTS customers with a breakpoint of 17 MW. The breakpoint represented the average DTS contract capacity of all services analyzed for the cost function in the *Customer Contribution Study*. The use of 17 MW suggested that all services less than the average capacity should be represented by one cost function, while all service above the average should be represented by a different cost function. The AESO later concluded this approach was inappropriate, because data did exist in the *Customer Contribution Study* for projects from 7.5 to 17 MW, and those projects were reasonably represented by the average cost function developed in the *Study*. The breakpoint was accordingly moved to 7.5 MW as discussed in part (b) above.
- (d) The data requested is attached to the AESO's response.
- (i) The average DTS contract is 20.3 MW and the median DTS contract is 12.8 MW.
- (ii) The average transformer size is 45.4 MVA and the median transformer size is 28.0 MVA.
- (iii) The following table provides the mode values for transformer size (MVA) and DTS contract size (MW).

Range of Transformer Size	Mode (MVA) Transformer Size	Mode (MW) DTS Contract Size
<=5 MVA	5.0	none
5.6 - 10 MVA	8.0	4.5
11 - 25 MVA	25.0	11.0
26 - 40 MVA	28.0	17.5
41 - 50 MVA	50.0	20.0
>50 MVA	60.0	59.0

**Title:** POD Costs

**Preamble:** The AESO has developed an average cost function with an  $R^2$  of 0.26. The AESO described this level of  $R^2$  as moderate.

**Reference:** S4, PAGE 13 AND PAGE 19

**Request:**

- (a) Please provide a full definition of R-squared.
- (b) Please provide the basis for declaring that 0.26 is a moderate level for  $R^2$ .
- (c) Please provide the  $R^2$  levels AESO believes are reasonable and relevant to be used for:
  - (i) A general trend awareness or relationship perspective only
  - (ii) A detailed billing and financial accounting perspective

**Response:**

- (a) The AESO used the following definitions of  $R^2$  and correlation in analyzing the data from the customer contribution study. The definition for  $R^2$  is reproduced from - *Statistics*, 10th edition, by James T. McClave and Terry Sincich, Pearson Prentice Hall, Upper Saddle Ridge, NJ, 2006.

*Chapter 11, Section 7:*

*The coefficient of determination is the proportion of the total sample variability (of the dependent variable) explained by the regression relationship*

*$r^2 = (\text{explained variability by the regression equation}) / (\text{total variability of the dependent variable})$*

*As a formula from the computer output:*

*$r^2 = (\text{Total sum of squares of the } y\text{'s} - \text{error sum of squares}) / \text{Total sum of squares of the } y\text{'s}$*

*Practical interpretation of the Coefficient of Determination,  $r^2$ :*

*100( $r^2$ )% of the sample variation in  $y$  (measured by the total sum of squares of the deviations of the sample  $y$  values about their mean  $\bar{y}$ ) can be explained by (or attributed to) using  $x$  to predict  $y$  in the straight-line [regression] model.*

(b) In an effort to provide some context to the results produced in the Study, the AESO referenced – *A Primer of Statistics for Non-Statisticians*, by A. Franzblau - Harcourt, Brace & World (1958) Chapter 7 pages 81-83 for guidance in the interpretation of the statistical results produced from the customer contribution study. Franzblau provides the following suggestions for interpreting the correlation coefficient. Please note the use of “coefficient” refers to R, and not  $R^2$  in this excerpt.

- Reliable coefficients of correlation ranging from zero to about .20 may be regarded as indicating *no or negligible correlation*
- Reliable coefficients of correlation ranging from about .20 to .40 may be regarded as indicating a *low degree of correlation*
- Reliable coefficients of correlation ranging from about .40 to .60 may be regarded as indicating a *moderate degree of correlation*
- Reliable coefficients of correlation ranging from about .60 to .80 may be regarded as indicating a *marked degree of correlation*
- Reliable coefficients of correlation ranging from about .80 to 1.00 may be regarded as indicating *high correlation*

Franzblau also notes that statistical results are a measurement and when used in conjunction with the above mentioned classifications require some qualitative context in order to interpret the results:

*The reader should learn to think of the coefficient of correlation in the same terms as he thinks of a yardstick or thermometer. All of them are instruments which render quantitative measurements without qualitative implications. No one would think of assuming ipso facto that a measurement of 2 feet 6 inches is less satisfactory than a measurement of 3 feet. It depends clearly on the circumstances – what we are measuring and why – not the measurement itself.... The function of a coefficient of correlation is to measure the degree of association between two variables. We have no more right to assume that all correlations “ought” to approximate 1.00 than we have to assume that all measurements of length “ought to approximate 3 feet. In certain situations a correlation of .00 would be regarded as quite satisfactory, and in others a correlation of .90 would be regarded as quite unsatisfactory. In still other situations it would be absolutely impossible to render any judgment in qualitative terms. The coefficient in such cases stands merely as a statement of fact....*

The AESO acknowledges that if someone were simply to look at the above mentioned table, an R value of 0.51 (or  $R^2$  value of 0.26) would be regarded as a moderate correlation. But as discussed in the above passage, the interpretation of coefficient results also depends on the particular circumstances, and these may change the meaning of the results. The AESO submits the correlation results in its cost function continue to be moderate when the following points are also considered in the analysis:

- Application (Section 6.5.3 Page 20)
  - The correlation analysis was somewhat limited by the number of projects in the total data set, since sample sizes of less than 30 generally provide lower-confidence representations of a total population.
  - Non-linear regression analysis was also completed, but similarly did not provide better regression coefficients than the linear analysis.
  - Although the variability of costs within the data set is significant, the projects nevertheless exhibit a clear trend of cost increasing as capacity increases

- Application (Section 4.5.2 Page 18)
    - The observed scatter of total project costs as a function of DTS capacity is not unreasonable when the lack of correlation of radial line costs to DTS capacity and the moderate correlation of substation costs to DTS capacity are considered. Radial line costs will add to the data scatter, but the AESO notes that the moderate correlation of substation cost to DTS capacity indicates inherent scatter in the data even when radial line costs are excluded. The AESO attributes the variability of substation costs to different substation configurations, varying geography and construction conditions, and different levels of complexity for each project.
  - The AESO demonstrated in its 2005/2006 GTA and in the TCE Complaint application (No. 1431750) - and the EUB accepted the AESO's position - that there are numerous considerations that influence the final interconnection configuration for system access service request, that all provide the same standard and functionality of service. This is further demonstrated by the wide number of different substation configurations interconnected to the AIES as provided in Attachment TCE.AESO-001 (Application No. 1431750).
- (c) Based on the discussion in (b) above, the AESO believes the analysis and interpretation of the analysis results are reasonable in response to the EUB's directive, in the context of determining a cost function to be used as the basis for the maximum investment function for the AESO's tariff.

**Title:** POD vs. Local and Bulk Costs

**Preamble:** The 2004-cost causation report stated that EPCOR/Enmax did not provide enough data to functionalize local costs on economics and therefore the AESO functionalized costs based on available data. In the final analysis, the EPCOR/Enmax data yielded a POD to local/Bulk breakdown of 68.3%, while ATCO was 28.6% and Altalink was 35.8%.

**Reference:** Transmission cost causation study, 2004, page 27

**Request:**

- (a) Please describe the data that was missing from the EPCOR/ Enmax information available to the AESO.
- (b) Please provide the final functionalization of costs including the assumptions that were made to overcome this missing data.
- (c) Please describe how the missing data affected the results.

**Response:**

- (a) EPCOR and ENMAX were unable to provide net book value on the basis of each line and substation. They were able to provide net book value on an aggregate basis for lines, PODs, and POSs.
- (b) All of the EPCOR and ENMAX lines are functionalized as Local System, and all substations were functionalized as POD with exception of the substations providing service to generating plants, which were functionalized as Bulk. The assumption made was that all lines are Local System.
- (c) The inability to provide net book value on the basis of each line may result in some line being functionalized as Local System whereas some of the line may have otherwise been functionalized as Bulk System. The EPCOR and ENMAX Local System represent less than 3% of the total net book value of transmission assets, and therefore any impact on results is immaterial.

**Title:** POD Costs

**Preamble:** From the original cost causation study, the AESO performed an analysis on 109 of the over 400 PODs in the Province.

**Reference:** Customer Contribution Study, AESO 2007 GTA, Terms & Conditions consultation, page. 24

**Request:**

- (a) Please provide all available data for the 109 PODs used in the AESO's analysis?
- (b) Please provide all data on all PODs used in the original cost/causation study for 2004.
- (c) If this data is subject to a confidentiality agreement with each TFO, can the AESO provide the data in a way that maintains confidentiality but provides information on POD size, original cost, NBV, in-service date?

**Response:**

- (a) Please see attached Schedule PPGA.AESO-007 (a),
- (b-c) The data provided in part (a) includes all information available from the TFO data which was used by the AESO in its validation of the POD cost function.

**Title:** POD Costs

**Preamble:** The AESO has gathered data from customer interconnections since 1999.

**Reference:** Customer Contribution Study, AESO 2007 GTA Terms and Conditions, page 12

**Request:**

- (a) Please describe, in detail, the AESO's current method of gathering interconnection cost data on all interconnection projects by all parties (TFOs)?
- (b) Is the data gathering process and content the same between parties? If not, please describe the differences.
- (c) In the AESO's view, is this data gathering system optimal in ensuring that costs gathered are accurate and can effectively be used for rate design?
- (d) If the AESO is of the view that their data gathering system can be improved, please describe any plans the AESO may have to improve their capability in this area.

**Response:**

- (a) In August of 2005 the AESO implemented ISO Rule "*ISO 9.1: Transmission Facility Projects*" which obligates the TFOs to provide standardized project estimates and cost information during different stages of the project, amongst other things. This rule was created as a response to the Transmission Regulation 174/2004 "*Part 3 Transmission Facility Projects*".

The first estimate to be provided by the TFO is the "*Needs Application Cost Estimate*" which then accompanies the Need Identification Document (NID) or Need Information Filing (NIF) that is submitted to the EUB by the AESO. This estimate has an accuracy of +/- 30%. The second estimate to be provided by the TFO is a "*Service Proposal Estimate*" which accompanies the Service Proposal provided by the TFO, and is required by the AESO prior to the AESO issuing a Direction to the TFO to proceed with filing a Transmission Facility Application to the EUB. This estimate has an accuracy of +20/-10%. The final cost information provided by the TFO to the AESO is a "*Final Cost Report*" and is to be provided approximately six months after energization of the project. The format of these standardized estimate/cost templates are available on the AESO's website at <http://www.aeso.ca/transmission/9993.html>. A copy of the three templates is also attached for reference as attachments PPGA.AESO-008-A - Needs Application Cost Estimate, PPGA.AESO-008-B - Service Proposal Estimate, PPGA.AESO-008-C - Final Cost Report.

- (b) Yes. Please refer to (a) above.

- (c) Yes, the estimate and cost data gathered as per (a) above is sufficient for rate design purposes in the AESO's Application.
- (d) No improvements are planned at this time as the estimate and cost data gathered as per (a) above is sufficient for rate design purposes in the AESO's Application.

**Title:** POD Costs

**Preamble:** The PPGA understands that no POD less than 7.5 MW has been interconnected to the transmission system since 1999 and that none are planned to be connected.

**Reference:** Alberta Transmission System, 2006 Transmission Cost Causation Update, September 15, 2006, page 55

**Request:**

- (a) Why is a marginal cost study (PODs in 2007 dollars) relevant to determining POD costs to smaller PODs?
- (b) If maintenance costs for smaller PODs are more relevant for cost/causation, please describe the plans the AESO has in place to study these maintenance costs for different load sizes.
- (c) Likewise, does the AESO concur that in general, urban POD costs are higher than rural costs? Generally, what extra costs do the urban locations incur? Please provide the various categories of such costs.
- (d) Please describe how the AESO classification of standard costs completely allocates these costs to the customer, rather than the system. Specifically please address: environmental and ROW costs, underground, building costs, land costs, reliability, safety, stakeholder sessions, size of footprint, etc.
- (e) Please describe if and how the AESO has examined the rural vs urban cost/ causation variances in its POD rate design?

**Response:**

- (a) The AESO did not perform a marginal cost study but rather an analysis to determine the proportion of transmission costs that should be allocated to the customer directly and those costs that should be recovered from all customers.
- (b) It is the AESO's general understanding that there is a minimum O&M cost incurred by a TFO regardless of the POD size and that beyond the minimum, O&M costs roughly increase on a linear basis relative to the size of the POD. As the recommended cost and investment functions follow a similar pattern, the AESO submits further analysis is not required.
- (c) The AESO did not perform any analysis to distinguish urban and rural POD costs. The AESO submits it is not appropriate and therefore unnecessary to distinguish between urban and rural PODs since, in accordance with Section 30 of the Electric Utilities Act,

the rates in the tariff can not be different as a result of the location of the customer on the transmission system.

- (d) Standard costs are all the necessary capital costs required to interconnect the customer to the AIES. Standard costs are then determined to be customer-related or system-related in accordance with Article 9 of the AESO's Terms and Conditions.
- (e) Please refer to part (c) above.

**Title:** POD Charge

**Preamble:** The AESO used the minimum Y-intercept approach in their analysis.

**Reference:** Customer Contribution Study, AESO 2007 GTA, Terms & Conditions, page. 19

**Request:**

- (a) Please provide a summary of the NARUC information pertaining to the use of the minimum Y-intercept approach.
- (b) Is the AESO aware of any other transmission rates set in North America that use this minimum intercept approach? If so please provide information on this situation.

**Response:**

- (a) Please refer to the response to Information Request BR.AESO-014.
- (b) No, the AESO is not aware of any other transmission rates that use this approach. Please refer to the response to Information Request PPGA.AESO-002 (a-e) for additional information.

**Title:** POD Charge

**Preamble:** To create the POD charge, the AESO made a number of assumptions and calculation steps. The PPGA has endeavored to capture these steps and requests that the AESO confirm and clarify the steps and methods documented by the PPGA.

**Reference:** Included in each part.

**Request:**

- (a) The PPGA understands that the POD charge is 40.9% of the total revenue requirement. The 40.9% was calculated from the Alberta Transmission System, 2006 Transmission Cost Causation Update, September 15, 2006 report. Reference: S4, page 14. Please confirm.
- (b) The original Cost/Causation report (referenced below) displayed two graphs to help calculate the fixed component of the POD charge. Each graph for both Altalink and ATCO PODs showed the NBV of each POD along with the corresponding MVA of the associated POD transformer. In this report, costs were classified to the customer component of the POD charge by taking the Y-intercept of the regression line on each graph, and dividing it by the average NBV of all PODs in the service territory. While the r-squared was not displayed in each graph, the AESO has stated publicly that it was approximately 0.1. Reference: S4, page 5, Alberta Transmission System, Cost Causation study, dated September 15, 2004, page 42, 43. Please confirm.
- (c) To calculate the AESO's recommended POD charge for the 2007 GTA, the AESO desired to improve the data reliability. To this end, the AESO gathered data on all greenfield and upgrade projects from their own database. The data in this database includes all projects completed since 1999. From this data set, the AESO chose to only use data on greenfield sites (30 in total); so that the POD charge analysis and the contribution analysis used the same data set. The assumption inherent in the use of the greenfield data is that the POD function derived from this sample is representative of the entire data set of the NBV of all PODs. Reference: Customer Contribution Study, AESO 2007 GTA Terms and Conditions Consultation, page 12. Please confirm.
- (d) The greenfield data set contained no data below 7.5 MW of DTS contract capacity. The AESO reviewed the all POD data set from the original cost/ causation study (2004) and selected 13 PODs with known in-service dates that had DTS contract capacities of below 7.5 MW. While the 13 PODs data was provided by the AESO in their filing, the remainder of the POD data from the 2004 study was not included by the AESO in the filing. Reference: Section 6, page 19. Please confirm.

- e) The AESO took the greenfield data, as well as the 13 PODs below 7.5 MW data and used the CPI index from Alberta to inflate each POD cost to 2007 dollars. Reference: Section 6, page 29. Please confirm.
- f) The AESO created a regression line from the Greenfield data. The regression line has an R-squared of 0.26. Reference: Section 6, page 20. Please confirm.
- g) The AESO used a minimum y-intercept approach to create a Y-intercept for the cost function by using the 13 PODs less than 7.5 MW. The Minimum Y-intercept approach was adopted from the NARUC Electric Utility Cost Allocation Manual, page 92, January 1992. Reference: Customer Contribution Study, AESO 2007 GTA, Terms and Conditions consultation, page. 19. Please confirm.
- h) The AESO chose to use 7.5 MW as the breakpoint for POD costs. This breakpoint was determined through the segregation of data - greenfield data is above 7.5 MW, 13 point data from the 2004 contribution study is below 7.5 MW. Reference: S4, page 13. Please confirm.
- i) The AESO used the minimum y-intercept point and connected this point to the average cost line (regression line through the Greenfield sites), at 7.5 MW. The resulting Y-intercept, slopes and R-squared is:
- (i) Y-intercept: 0.947 Million
  - (ii) Slope below 7.5 MW: 0.621 Million/MW
  - (iii) Slope above 7.5 MW: 0.154 Million/MW
  - (iv) R-squared: 0.26
- Reference: S4, page 13, page 19. Please confirm.
- j) To obtain a rate, the AESO required billing determinants. These billing determinants were obtained from an AESO forecast of all POD customer data (not included with the AESO filing). Using 7.5 MW's as a break point, the AESO gathered:
- (i) Total Customer Months to be used for the fixed customer charge
  - (ii) MW months to be used to determine the monthly POD charge to different sizes of DTS loads.
- Reference: Rate Calculations.xls, tab 5.9 determinants. Please confirm.
- Please provide the 2007 forecast MW data by POD in the same format as found in Appendix E.
- k) The AESO took the total revenue requirement and using 40.9% for POD costs, created the POD revenue requirement of \$182.2 Million for wires and 6.4 Million for non-wires costs. Reference: Rate Calculations.xls, tab 5.5 DTS rate. Please confirm.
- l) The 182.2 Million, plus 6.4 Million POD costs, required classification to customer and demand. This was accomplished by taking:
- (i) Y-intercept (0.947) multiplied by the customer months (4854); plus
  - (ii) Slope for less than 7.5 MW (.621) multiplied by the MW months below 7.5 MW (32,514); plus
  - (iii) Slope for above 7.5 MW (.154) multiplied by the MW months above 7.5 MW (82,133)
  - (iv) Adding these calculations together.
  - (v) Dividing each subtotal a, b, c by the total to get relative percentage of costs.

Reference: S4, page 14. Please confirm.

- (m) Each percentage calculated in step I.) was then multiplied by 182.2 Million plus \$6.4 Million, to create the total amount to be collected by the customer and demand charges. Reference: Rate Calculations.xls, tab 5.5 DTS rate. Please confirm.
- (n) These totals were divided by the customer months (customer charge), MW months applicable to each slope to create the final customer charge and demand charges as shown below:
  - (i) Customer Charge: \$4,762 /Month
  - (ii) Demand charge, less than 7.5 MW: \$3,129
  - (iii) Demand Charge, greater than 7.5 MW: \$776
 Reference: Rate Calculations.xls, tab 5.5 DTS rate. Please confirm.

**Response:**

- (a) Confirmed.
- (b) Confirmed.
- (c) Not confirmed. The assumption underlying the use of the *Customer Contribution Study* data is not that the cost function will be representative of the NBV of all existing PODs, but that the **relative proportions of fixed cost and demand-related costs** will be the representative. Since the cost function is prorated to recover that portion of the AESO's revenue requirement attributed to the POD function, the actual cost function itself is immaterial as long as the relative proportions of its components are appropriate.
- (d) Confirmed, and please refer to the response to Information Request PPGA.AESO-003 (d) for additional information.
- (e) Confirmed.
- (f) Confirmed.
- (g) Confirmed.
- (h) Confirmed, with one clarification. The breakpoint was set solely on the basis that the greenfield data included only PODs of 7.5 MW capacity and larger. Therefore, when looking to the TFO data (as described in part (d) above), it was only necessary to extract the PODs less than 7.5 MW.
- (i) Confirmed, with one clarification. The correlation coefficient applies only to the cost function for capacities of 7.5 MW and larger (the greenfield projects).
- (j) Confirmed.

The AESO considers individual customer billing determinants to be confidential information, and does not consider it appropriate to disclose such information publicly.

- (k) Confirmed, with the following clarification. POD costs were determined as 40.9% of the total wires revenue requirement of \$445.2 million, plus a *pro rata* share of the non-wires revenue requirement of \$15.2 million.
- (l) Confirmed.
- (m) Confirmed.
- (n) Confirmed.

**Title:** Primary Service Credit

**Preamble:** S4, page 51

**Reference:** The AESO used a number of steps to determine the level of the Primary Service Credit. Please confirm these steps below:

**Request:**

- (a) The AESO assumed that the PSC credit from the 2006 tariff reflects the cost of transformation for all substations in the Province. Please confirm.
- (b) The AESO took the 2006 PSC of \$660/MW and multiplied this by the 2007-billing determinant of 114,716.8 MW months. This created total estimated transformation costs per year of \$75.7 Million. Please confirm.
- (c) The total estimated transformation costs was then divided by the total POD related revenue requirement of \$189.7 Million, to obtain a percentage of transformation to total POD costs of 40%. Please confirm.
- (d) The AESO then multiplied each part of the proposed POD charge by the 40% calculation, resulting in a PSC credit of (subject to adjustment for sub-station fraction):
  - (i) Customer Credit: \$1,905/Month
  - (ii) Less than 7.5 MW credit: \$1,252/MW
  - (iii) Greater than 7.5 MW credit: \$310/MWPlease confirm.

**Response:**

- (a-d) Confirmed.

**Title:** Capital Contribution

**Preamble:** In establishing the investment function such that 80% of projects are covered by the capital contribution, the AESO disregarded the 13 data points below 7.5MW as the assessment of the validity of this data lacked rigor.

**Reference:** S (F) - 26

**Request:**

- (a) Please confirm.
- (b) Please describe the reasons the AESO believes that these 13 data points below 7.5 MW lacked rigor.

**Response:**

- (a) Not confirmed. The 13 data points below 7.5 MW were incorporated into the derivation of the raw cost function. The 13 projects were, however, excluded from the derivation of the multiplier applied to the raw cost function to arrive at a maximum investment function where 80% of projects do not pay a contribution. The proposed investment function is designed to apply going forward, and so the AESO surmised that recent history would be a reasonable representation of projects expected to be constructed in the near future. As there were no projects under 7.5 MW constructed between the years 1999 through 2006, it was considered reasonable to assume such projects will not be constructed in the near future and therefore the multiplier was established such that 24 of the 30 recent projects would be fully covered by the proposed maximum investment function.
- (b) The data from the Transmission Cost Causation Study lacked rigor in the sense that it does not contain the level of cost detail required to meet the stringent requirements outlined in the Study's terms of reference. Prior to proceeding with the Customer Contribution Study, stakeholders were consulted to determine the scope and purpose of the Study. A majority of stakeholders felt that accurate, fully deconstructed interconnection project costs were necessary in the development of the investment cost function. As outlined in page 20 of the Customer Contribution Study, the data set containing the detailed costs did not contain interconnection projects below 7.5 MW. The AESO therefore relied on the Transmission Cost Causation Study for the additional data points.



**Title:** Interconnection Standards - reliability

**Preamble:** Is the AESO aware that in BC, Montana and Wyoming, 25 kV is not allowed by utilities for large 5000 HP motors in order to protect system reliability?

**Reference:** Section 7, page 10

**Request:**

Please comment.

**Response:**

The AESO is aware that distribution companies in these jurisdictions determine whether or not a 5000 HP motor may be connected to their 25 kV system. If system reliability is in question, the distribution company may require the customer to install protection equipment or will direct the customer to connect their large motor at a transmission level voltage.

**Title:** Capital Contribution

**Reference:** S (F) – 26 AND 27

**Request:**

- (a) Which data set was used for the scaling of the regression function and how did this data set differ from the data set used in calculating the regression function?
- (b) How did the AESO calculate the scaling factor of 1.15149? Please provide a step by step breakdown of the method to calculate this factor.

**Response:**

- (a) EUB Direction 13A directed the AESO to determine an appropriate multiplier such that 80% of projects would not pay a contribution. The data set used to calculate the 80/20 multiplier can be found in Appendix G – Customer Contribution Data under the tab labeled “All Projects”. The recommended “raw cost function” was calculated using the sample data collected for the study, as well as a small project sample extracted from the Transmission Cost Causation Study.

When applying the 80/20 multiplier, the cost function was inflated such that 80% of the projects identified in “Greenfield” project sample for the Customer Contribution Study would be covered by the proposed investment.

- (b) The scaling factor (or “multiplier”) was calculated as the minimum number by which each component of the raw cost function would be multiplied, such that 80% of the 30 “Greenfield” projects (or 24 projects) would fall under the recommended investment function. The tab labeled “All Projects” in Appendix G – Customer Contribution Data shows the calculations and formulas in Excel spreadsheet format. The column labeled “Captured” identifies those projects that would be 100% covered by AESO investment using the recommended investment function.

**Title:** POD/ Local Costs

**Preamble:** The updated Cost Causation study did not change the alignment of costs between local and POD due to the insufficient breakdown of costs provided by the TFO's.

**Reference:** Alberta Transmission system, 2006 Transmission Cost Causation Update, September 15, 2006, page 46

**Request:**

- (a) The Cost Causation study stated that the expected impact of a refinement in local/ POD costs was "small". Please describe how this conclusion was reached? Please provide any calculations that were used to reach this decision?
- (b) Please describe the details that were missing from the TFO costs to provide this breakdown.
- (c) Does the current method of gathering costs by the AESO, enable the AESO to provide this measure? If so, please use the 30 greenfield sites as a sample and provide this estimate.

**Response:**

- (a) There is insufficient detail in TFO cost data to sub-functionalize the transmission system in a manner different than that completed in the original *Transmission Cost Causation Study* provided as Appendix B to the AESO's 2006 GTA filed on January 31, 2005. No calculations were completed because there is not sufficient data to use different definitions of sub-functions. The impact was assessed as small because the amount of property in question is expected to be small and is a part of the POD sub-function, which itself is less than 40% of the transmission property.
- (b) A new definition would be required prior to determining what detailed data is required. For example, would any of the high voltage switchgear (i.e., switchgear associated with a radial feed, or the first feeder) or buswork be considered part of the POD function? Once the definition of local system and POD is developed, then the cost data would have to be obtained on the basis of that definition. There would also be some common costs that would have to be known and allocated between the local system and POD functions.
- (c) The greenfield site data does not contain enough detailed information to allow a revised alignment between local system and POD functions.

**Title:** Transmission Interconnection Standards

**Preamble:** The PPGA has very large motors (>3000 hp) at its installations. During new INTERCONNECTIONS, a decision must be made regarding the base case for an interconnection. Two separate documents seem to guide this decision: "AESO Generation and Load Standard, rev. 0A" and "Distribution point of delivery interconnection process guideline". As well; the AESO's website states that guidelines published on its website are not intended to "support INTERCONNECTION processes for direct connect industrial CUSTOMERS or generators".

**Reference:** S7, page 10, Distribution Point of Delivery Interconnection Process Guideline, AESO Generation and Load Standard, Rev 0A

**Request:**

- (a) In guiding the base case decision regarding transmission vs. distribution interconnections for industrial customers, please specify if the guideline referenced above is used in this determination.
- (b) If this guideline is used, please clarify why the AESO states on its website that the guideline is not intended to support interconnection processes for direct connect industrial customers or generators.
- (c) If the guideline is used to support the decision for direct connect industrial customers regarding the base case for transmission vs. distribution interconnects, how does the guideline and the AESO generation and load standard, REV 0A compliment each other or work together?
- (d) Please confirm that the following process is used to determine if transmission or distribution should be the base case for an interconnection from a single customer with a large motor:
  - (i) Load flow studies are conducted by the DFO to determine if the new load can be supplied from the existing distribution system, or by building a new distribution feeder from an existing substation. Please confirm.
  - (ii) If ampacity or voltage limitations exist in the model, the affected components are upgraded so that a new load can be supplied. If a new distribution feeder cannot supply the load with an acceptable voltage and ampacity, then a transmission solution is explored. Please confirm.
  - (iii) The DFO will also investigate load growth in the area of the interconnection. If load growth is high, a transmission option may be desirable. Please confirm.

- (iv) The DFO also economically evaluates the alternatives used in the various load flow alternatives, including line losses. Please confirm.
- (v) For a single large customer, a motor starting study is also required. The motor starting study ensures that motor starting from one customer does not create problems for other customers. The DFO will first study an attempt at starting the modeled motor across the line. If voltage fluctuations occur greater than the DFO standard, then motor starting aids are utilized. Please confirm.
- (vi) The customer is accountable for paying for and installing any motor starting aid at their site. Therefore, the customer determines if a motor starting aid will be installed. If a motor starting aid is not to be installed by the customer, the DFO will only model an across the line start-up. Please confirm.
- (vii) If, after modeling motor start-up with any customer installed motor starting aid, the voltage reduction techniques do not look promising, the DFO investigates the following alternatives:
  - (a) Reconductoring the existing feeder;
  - (b) Reconductoring the existing feeder and installing a series capacitor;
  - (c) The addition of a new feeder;
  - (d) The addition of a new distribution feeder and series capacitor, and finally
  - (e) A transmission option
 Please confirm.
- (viii) In evaluating the various alternatives outlined in f.(vii), the DFO is assuming that all the options studied offer the customer the same level of reliability. Please confirm.

The PPGA has several questions relating to the reliability of capacitor banks.

- (a) Has the AESO conducted a reliability study on Series Capacitor Banks (SCB's)?
  - (b) What is the manufacturers specifications for reliability (average % availability) for SCB's?
  - (c) Please confirm that when a SCB is used to support the motor starting for an industrial customer, and the SCB is out of service, it is likely that an industrial customer will likely not be able to start their motors.
  - (d) How many locations in Alberta are there SCB's for motors over 2500 hp? Please document the number of units, their location, service voltage, and age for all SCBs in the province.
  - (e) Does the AESO have a maintenance and outage record for this equipment? If so, please provide the records. What is the MTBF (mean time between failures?)
  - (f) What are the average equipment life and design life and SCB's?
- (ix) The DFO summarizes their studies in a table included in the guideline previously referenced. The standards expressed in the table are used by the DFO's in reaching their decisions regarding transmission vs. distribution base case analysis. Please confirm.
  - (x) Load growth potential is then examined and the potential impact this load growth potential will have on the motor starting capability. Please confirm.

- (xi) The DFO also economically also evaluates the alternatives used in the motor starting, including line losses. However, this evaluation does not include the cost of any soft start mechanisms that the customer installs. Please confirm.
- (e) Included in the AESO Generation and load standard is a reference to the IEC standard relating to the details on flicker measurement. Can the AESO please summarize this IEC standard?
- (f) The AESO has stated that customers can independently determine their appropriate form of soft start mechanism. Please confirm.
- (g) The results of the flicker limit tests for motor starting vary, depending on the placement of an interconnection within Alberta's electrical system. The base case for determining distribution vs. transmission connections that utilizes motor starting studies can therefore vary depending upon the area of the Province studied. Please confirm
- (h) Please summarize the steps used to determine the value of line losses used in the transmission vs. distribution analysis.
- (i) Please clarify how the AESO defines the most "economic" solution related to the transmission vs distribution base case? Does the AESO consider the macro level costs/impacts of the options on a broad, societal basis; or, only the cost/impact on the electrical grid?
- (j) Pertaining to i ) above please describe in detail how the costs and revenues are calculated, specifically:
  - (i) Does the AESO include maintenance, operating costs and reliability for the impact on the grid?
  - (ii) Does the AESO include the impact on lost provincial taxes, royalties and other revenue sources due to reliability variances?
  - (iii) Does the AESO include the financial impact on the customer on capital, operating and reliability?
  - (iv) Is life cycle costing used for this decision making? Please provide detail assumptions and criteria used for this economic evaluation.

**Response:**

- (a) The 'Distribution Point-of-Delivery Interconnection Process Guideline – Evaluation of Transmission versus Distribution Alternatives for Large Customers' provides the methodology to be used by the Distribution Facility Owner ("DFO") and/or Transmission Facility Owner ("TFO") to identify if the interconnection proposal for a new customer should be a Distribution Proposal or a Transmission Proposal.
- (b) If the assessment discussed in (a) above determines that the load is to be connected to the distribution system, the distribution guidelines as outlined in AE.AESO-003 (a) would provide guidance to the DFO in preparation of the interconnection proposal. If, on the other hand, the Transmission versus Distribution evaluation determines that the load is

to be connected directly to the transmission system (and assuming the customer receives a Section 101 waiver from the DFO), the AESO's Generation and Load Interconnection Standard (Rev 1 dated September 19, 2006) guides the development of the transmission interconnection proposal, not the distribution interconnection process guidelines.

- (c) As noted in (a) and (b) above the AESO evaluates the system access request utilizing the 'Distribution Point-of-Delivery Interconnection Process Guideline – Evaluation of Transmission versus Distribution Alternatives for Large Customers'. The results of the evaluation will then dictate which guidelines or standards will be utilized in the preparation of the final interconnection proposal.
- (d) The 'Distribution Point-of-Delivery Interconnection Process Guideline – Evaluation of Transmission versus Distribution Alternatives for Large Customers' discusses the considerations that should be investigated before deciding if the best solution is a transmission or distribution solution. In general, the AESO would agree with the points identified in (i) through (xi); however the specifics of the analysis are conducted by the DFO based upon the nature of the potential load addition. The specifics of this should be directed to the DFO to confirm.
- (e) As provided in the scope of the standard it "outlines principles which are intended to be used as the basis for determining the requirements for connecting large fluctuating loads (producing flicker) to public power systems."
- (f) Confirmed, assuming that they satisfy the applicable standards.
- (g) Confirmed.
- (h) As stated in on Page 5 of Section 3.4 in the 'Distribution Point-of-Delivery Interconnection Process Guideline – Economic Evaluation':  
  
"Both transmission and distribution system losses should be taken into account. Changes to the losses over time should be factored in the analysis. I<sup>2</sup>R losses should be evaluated in terms of future pool prices. The rationale for the pool price forecast must be provided. The cost impact of any reduction of transmission system demand should also be included if material.  
  
Cost of losses can be ignored provided the losses are small or the interconnection alternatives have nearly similar losses."  
  
(i) The economic analysis is outlined in the 'Distribution Point-of-Delivery Interconnection Process Guideline – Economic Evaluation' and considers the cost impact on the Alberta electric system.  
  
(j) Please refer to (i) above.



**Title:** Rate schedule - Pod costs

**Preamble:** The RGUCC has been classified to DTS tariff demand, energy and customer in the same proportion as the wires costs for bulk, local and POD.

**Reference:** Rate Calculations.xls, tab 5.3 DTS classification

**Request:**

Please confirm.

**Response:**

Confirmed. RGU Connection Costs are included in the DTS Tariff Revenue Offsets which are classified at line 21 of Schedule 5.3 in section 5 of the Application, in the same proportion as Total Wires costs at line 5 on the same Schedule.