

Topic: Proposed tariff cost increases to dual-use customers

Reference: Appendix I – Bill Impact Analysis spreadsheet AESO 2010 ISO Tariff - Appendix I - Bill Impact Analysis.xls and Section 4 — Rate Design, Page 67 of 268, Paragraphs 336.06 & 336.07

Preamble: “As illustrated in Figure 4-14, the majority of Rate DTS PODs (456, or about 91%) receive increases of $\pm 10\%$ based on Rate DTS charges and commodity costs. In addition, 46 PODs (about 9%) receive increases that range from $+10\%$ to $+47\%$.”

”Decision 2007-106 directed that services receiving an increase greater than 10% be examined in more detail. Table I-6 in Appendix I accordingly provides additional information on the 46 services receiving increases greater than 10% due to the proposed Rate DTS. Of those services, 41 (about 89%) are dual-use sites where services are provided under both Rate DTS and Rate STS.”

Direct connect dual-use customers make up less than 2% of the AESO’s revenue requirement; however, these accounts are proposed to be charged 18% of the proposed rate increase from 2009 to 2010. The DUC requests additional data to better understand that proposed rate increase.

Request:

- (a) Please confirm that the POD No. in column A of tab I-3 Per POD correlates to the POD No. in column A of tab I-4 Component. If not confirmed, please explain fully.
- (b) Please provide the number of substations that correlate to the 502 POD No. shown on tab I-3 Per POD.
- (c) For each of the following billing determinants provided on tab I-3 Per POD please explain how the billing determinant was derived, the data source and the time period, including an example where appropriate:
 - (i) Billing Capacity (MW)
 - (ii) Monthly Usage (MWh)
 - (iii) Load Factor (%)
 - (iv) Sub-station Fraction
 - (v) CMD
 - (vi) HMD
 - (vii) DTS Capacity (MW)
 - (viii) STS Capacity (MW)
- (d) Please confirm that the DTS Capacity provided in column H of tab I-3 Per POD is not equal to the DTS contract capacity for each POD No. customer. If not confirmed, please explain fully.

- (e) Please add the following information for each POD No. on tab I-3 Per POD in a revised spreadsheet. If the requested information is not available for each POD No., please provide the information the AESO has or has access to. If the AESO considers any of the requested information to be confidential, please forward to the DUC representative before April 12, 2010 a confidentiality agreement to allow this data to be provided to the DUC representative by April 28, 2010.
- (i) the DTS contract capacity for the POD No. customer
 - (ii) the STS contract capacity for the POD No. customer
 - (iii) the number of POD No. present at the physical substation
 - (iv) the Primary Service Credit amount if applicable under the AESO's current tariff
 - (v) the Primary Service Credit amount proposed to be applicable under the AESO's proposed 2010 tariff
 - (vi) an indicator to note if the POD No. is for a customer that has a DTS and STS contract at the same substation, i.e. a dual-use customer
 - (vii) an indicator to note if the POD No. has related Industrial System Designation
 - (viii) the AESO substation name identifier for the physical substation where the POD No. is present.

Response:

- (a) Confirmed. Consistency can be verified for any specific POD No. by comparing the "Average Monthly Bill (\$)" amounts, which appear in total on both tab "I-3 Per POD" and tab "I-4 Component".
- (b) The Rate DTS accounts in Appendix I are served through about 456 substations, some of which provide service to multiple accounts which may be either Rate DTS or Rate STS. The capacities of the 456 substations are shared between market participants in accordance with the definition of substation fraction provided in Appendix J to the application, which results in the following attribution of substations to Rate DTS and Rate STS market participants.

Rate	Equivalent Substations	Note
DTS	401.0	Sum of the shares of substations attributed to Rate DTS market participants, for the substations providing service to the Rate DTS market participants in Appendix I
STS	55.0	Sum of the shares of substations attributed to Rate STS market participants, for the substations providing service to the Rate DTS market participants in Appendix I
Total	456.0	Total number of substations used, either entirely or partially, to provide service to the Rate DTS market participants in Appendix I

The numbers provided above count multiple substations that are subject to totalized billing as a single substation, consistent with their treatment in the AESO's billing system.

- (c) All billing determinants provided on tab "I-3 Per POD" are based on recorded values extracted from the AESO's billing system over the period January to December 2008

and, for billing capacity, over the period January 2006 to December 2007 for the ratchets used in the determination of billing capacity.

- (i) Billing Capacity (MW) is the average of the monthly billing capacities calculated for each POD from January to December 2008, where billing capacity in a month is calculated as the greater of recorded values for:
 - the highest metered demand for that POD in the month;
 - 90% of the highest metered demand for that POD in the 24-month period including and ending in the month; or
 - 90% of the contract capacity for that POD in the month.
 - (ii) Monthly Usage (MWh) is the average of the monthly metered energy recorded for each POD from January to December 2008.
 - (iii) Load Factor (%) is the average annual load factor for each POD, calculated as 12 times the monthly usage from (ii) divided by the product of billing capacity from (i) and 8,760 hours.
 - (iv) Substation Fraction is the average of the monthly substation fractions recorded for each POD from January to December 2008, determined in accordance with the definition of substation fraction in Appendix J of the application.
 - (v) CMD is the average of the monthly coincident metered demands recorded for each POD from January to December 2008, determined in accordance with the definition of coincident metered demand in Rate DTS.
 - (vi) HMD is the average of the monthly highest metered demands recorded for each POD from January to December 2008.
 - (vii) DTS Capacity (MW) is the average of the monthly Rate DTS contract capacities recorded for each POD from January to December 2008.
 - (viii) Where one or more Rate STS accounts exist at the substation which provides service to the POD, STS Capacity (MW) is the total Rate STS contract capacity which existed at that substation in December 2008.
- (d) Not confirmed. The DTS Capacity provided in column H of tab "I-3 Per POD" is the average of the monthly Rate DTS contract capacities recorded for each POD from January to December 2008.
- (e) Please see Attachment DUC.AESO-001 (e) which provides the additional information in a version of the bill impact analysis based on the rates in revised section 5 of the application submitted on May 5, 2010.
- (i) DTS contract capacity is already provided on the "Per POD" sheet, as discussed in part (d) above.
 - (ii) An "STS at POD" column has been added on the "Per POD" sheet to indicate the STS contract capacity, if any, associated with the POD No. The previous "STS Capacity" column remains on the sheet and indicates the STS capacity at the

substation (whether associated with the POD No. or not) and used in the calculation of the substation fraction for the POD No.

- (iii) A “PODs at Sub” column has been added on the “Per POD” sheet to indicate the total number of Rate DTS points of delivery served through the substation through which the POD No. is served.
- (iv-v) Primary service credit amounts for 2009 and 2010 have been added on the “Component” sheet. Those amounts are included in the average monthly bill totals on the “Per POD” sheet.
- (vi-vii) “Type” and “ISD” columns have been added on the “Per POD” sheet to provide the requested information. The AESO used its best judgment to determine whether a POD No. was serving a dual use market participant.
- (viii) The AESO declines to provide the substation name identifier for each POD in the attachment.

The AESO considers that providing the substation name identifier in conjunction with the other detailed information provided in the attachment would allow specific market participants to be identified, together with their associated billing determinants and average bills. The AESO is particularly concerned about the disclosure of contract capacities, as contract capacity is a “forward-looking” billing determinant which frequently indicates a market participant’s expected system access in the future, in contrast to other billing determinants which generally reflect the market participant’s system access in the past. The AESO accordingly considers that providing substation name identifiers would allow specific market participants to be identified, which could result in harm to a market participant’s competitive position by disclosing information that would otherwise be unavailable. The AESO therefore declines to provide the requested substation name identifier to maintain confidentiality of market participant information, in accordance with section 31(1)(c) of Commission Rule 001 on Rules of Practice.

Topic: POD rate design

Preamble: During the summer of 2009 stakeholder consultation sessions several consumer representatives indicated support for a revised POD rate design where POD charges would be proportional to the value of the assets installed to provide service. The DUC requests data to explore this concept further.

Request:

For each physical substation that is used to serve an end use customer (i.e. excluding system substations), please provide as much of the following data as the AESO has or has available to it, including information from the TFOs. If the AESO considers any of the requested information to be confidential, please forward to the DUC representative before April 12, 2010 a confidentiality agreement to allow this data to be provided to the DUC representative by April 28, 2010.

- (i) The AESO substation name identifier
- (ii) The primary substation voltage
- (iii) The secondary substation voltage(s)
- (iv) The number of transformers installed
- (v) The size of each transformer installed
- (vi) The number of primary substation voltage breakers
- (vii) The number of secondary substation voltage breakers
- (viii) The total DTS contract capacity for all customers served from the substation
- (ix) The total STS contract capacity for all customers served from the substation
- (x) The 2009 monthly average billing capacity in MW for all customers served from the substation
- (xi) The 2009 monthly average coincident billing demand in MW for all customers served from the substation
- (xii) The 2009 monthly average energy consumption in MWh for all customers served from the substation

Response:

Please see Attachment DUC.AESO-002.

Breaker information (items (vi) and (vii)) is not readily available, although the number of lines supplying the substation is an indication of the primary voltage breakers. As well, billing volumes information (items (x), (xi), and (xii)) is provided for 2008 rather than 2009 to allow utilization of the data on which Appendix I of the application was based.

Topic: POD Raw Cost Function and Resulting DTS POD Charges

Reference: [2010-03-04 AESO 2010 ISO Tariff - Appendix G - POD Cost Function Workbook.xls](#)

Preamble: The selection of the demand level for the first line segment of the POD cost function can have an impact on the resulting DTS and PSC rates. The DUC requests additional analysis to understand the impact of the assumptions made.

Request:

- (a) Please explain the rationale for using 0.1 MW in the determination of the slope for the first line segment of the POD cost function.
- (b) Please provide revised Appendix G - POD Cost Function Workbook, Section 5 – Rate Calculations and Appendix I – Bill Impact Analysis spreadsheets and a revised table of investments levels (i.e. table under Section 8.8.4(b) of the proposed Terms and Conditions) assuming the 0.1 MW value in the determination of the slope for the first line segment of the POD cost function was changed to 0.01 MW.
- (c) Please provide a revised Appendix G - POD Cost Function Workbook, Section 5 – Rate Calculations and Appendix I – Bill Impact Analysis spreadsheets and a revised table of investments levels (i.e. table under Section 8.8.4(b) of the proposed Terms and Conditions) assuming the 0.1 MW value in the determination of the slope for the first line segment of the POD cost function was changed to 1.0 MW.

Response:

- (a) The 0.1 MW value was used in the methodology established by the Alberta Energy and Utilities Board in Decision 2007-106 for the calculation of the POD cost function line segments from the POD cost power function. The Board explained the methodology in section 5.7.7 (page 52) of the decision as follows:

*This contrasted with the approach adopted by Board staff, which calculated the linear functions by joining the calculated power function value for **0.10MW (the first data point in the 48 point set)** to the calculated power function value for 7.5MW by way of straight line.*
[bolding added]

The capacity of the smallest of the 64 data points used for the POD cost function in the 2010 tariff application remains unchanged at 0.1 MW.

- (b) Please see Attachments DUC.AESO-003 (b)-A, -B, and -C for the revised Appendix G *POD Cost Function Workbook*, section 5 rate calculations, and Appendix I bill impact analysis, respectively, with 0.01 MW used to establish the first POD cost function line

segment. Please note that the rate calculations and bill impact analysis are based on the revised section 5 of the application submitted on May 5, 2010.

The corresponding maximum investment level is as follows:

Tier	Maximum Investment Level	
	As Filed 0.1 MW Endpoint	DUC.AESO-003 (b) 0.01 MW Endpoint
Substation fraction (for new points of delivery only)	\$51,050/year	\$21,150/year
First (7.5 × substation fraction) MW of contract capacity	\$34,650/MW/year	\$38,600/MW/year
Next (9.5 × substation fraction) MW of contract capacity	\$12,800/MW/year	\$12,800/MW/year
Next (23 × substation fraction) MW of contract capacity	\$7,750/MW/year	\$7,750/MW/year
All remaining MW of contract capacity	\$4,200/MW/year	\$4,200/MW/year

- (c) Please see Attachments DUC.AESO-003 (c)-A, -B, and -C for the revised Appendix G *POD Cost Function Workbook*, section 5 rate calculations, and Appendix I bill impact analysis, respectively, with 1.0 MW used to establish the first POD cost function line segment. Please note that the rate calculations and bill impact analysis are based on the revised section 5 of the application submitted on May 5, 2010.

The corresponding maximum investment level is as follows.

Tier	Maximum Investment Level	
	As Filed 0.1 MW Endpoint	DUC.AESO-003 (c) 1.0 MW Endpoint
Substation fraction (for new points of delivery only)	\$51,050/year	\$111,350/year
First (7.5 × substation fraction) MW of contract capacity	\$34,650/MW/year	\$26,600/MW/year
Next (9.5 × substation fraction) MW of contract capacity	\$12,800/MW/year	\$12,800/MW/year
Next (23 × substation fraction) MW of contract capacity	\$7,750/MW/year	\$7,750/MW/year
All remaining MW of contract capacity	\$4,200/MW/year	\$4,200/MW/year

Topic: Historical Proposed and Actual Rate Increases to Dual-Use Customers

Reference: Section 4 — Rate Design, Page 67 of 268, Paragraph 336.07

Preamble: “In Decision 2008-037 on the AESO’s 2007 General Tariff Application Refiling, the Commission commented, with respect to dual-use services receiving greater than 10% increases at that time, “The Commission does not consider it reasonable to offer a subsidy to these dual-use customers as there is no evidence to suggest that their total DTS and STS billings exceed the threshold.””

The DUC requests a summary of historical proposals and regulator approved tariff impacts on dual use customers to better understand the development of tariffs for dual use customers.

Request:

- (a) Please provide the context in which the Preamble quote from the AUC was made.
- (b) For each general tariff application since 2001 please provide the following for dual use customers being served at primary transmission voltage (i.e. DTS customers with customer owned substations):
 - (i) a summary of the Transmission Administrator’s or AESO’s proposed DTS and PSC/COS/COT tariff treatment for dual use customers being served at primary transmission voltage
 - (ii) a summary of the Transmission Administrator’s or AESO’s proposed PSC/COS/COT tariff eligibility criteria
 - (iii) a quantitative assessment of the proposed DTS and PSC/COS/COT tariff impact on dual use customers by comparing the tariff in effect at the time of the application to the proposed tariff
 - (iv) a summary of the EUB or AUC approved tariff for dual use customers being served at primary transmission voltage where the tariff was not approved as filed
 - (v) a summary of the EUB or AUC approved PSC/COS/COT tariff eligibility criteria
 - (vi) a quantitative assessment of the regulator approved DTS and PSC/COS/COT tariff impact on dual use customers by comparing the tariff in effect at the time of the application to the EUB or AUC approved tariff
- (c) Please discuss the AESO’s tariff design philosophy towards dual use customers being served at primary transmission voltage over the past decade.

Response:

- (a) The quoted text was in section 3.5 of Decision 2008-037, titled “Mitigation of Rate Shock”. The Commission summarized the original direction given to the AESO in Decision 2007-106, commented on the AESO’s response, and went on to discuss the 13 PODs receiving cost increases above the 10% threshold under the refiled rates. The

Commission noted that 2 of the PODs were dual-use customers, followed by the quoted text. The Commission then continued on to discuss the dollar amount required to offer relief to the other 11 PODs, and the recovery of that subsidy through the AESO's Rate DTS deferral account.

The AESO considers the general context of the quoted text to be bill impacts, and the quoted text is therefore directly relevant to the AESO's discussion of bill impacts in section 4.20 (pages 66-70) of the application.

- (b) Please see Attachment DUC.AESO-004 (b). Tariff applications have not been included in the attachment when they only updated rate levels and did not otherwise affect tariff provisions applicable to dual use customers. For example, the 2009 rates update application is not included, as it only adjusted rate levels.

As well, the AESO has summarized only those aspects of Rate DTS that are specifically relevant to the primary service credit — namely, the POD charge or, where Rate DTS did not include a POD charge, the interconnection charge. The bulk system, local system, operating reserve, voltage control, and other system support services charges do not affect the derivation or application of the primary service credit and are therefore not included.

- (c) The AESO applies the same tariff design philosophy for service to dual use customers as for service to other market participants. The AESO designs the primary service credit in accordance with the rate design principles discussed in section 4.2 (pages 27-28) of the application, in particular:
- provision of appropriate price signals that reflect all costs and benefits, including in comparison with alternative sources of service; and
 - fairness, objectivity, and equity that avoids undue discrimination and minimizes intercustomer subsidies.

Over the past decade the primary service credit has evolved in conjunction with the Rate DTS POD charge and the maximum investment level, through studies and detailed analysis of the underlying costs. The AESO considers the Rate DTS POD charge, the primary service credit, and the maximum investment level should be based on the same POD cost function to ensure comparability and consistency between these tariff components.

Topic: Customer Option to take the PSC

Reference: Section 4, Rate Design, Page 54 of 268, Paragraphs 265 - 267

Preamble: “The AESO also proposes in this application that Rate PSC be no longer considered an option for a market participant whose connection does not include conventional transformation facilities owner (sic) by a TFO.”

The DUC requests additional information on why the AESO is proposing to remove the option to receive the PSC.

Request:

- (a) Please confirm that the AESO’s investment policy does not differentiate between local, POD radial line and POD substation related costs. If not confirmed, please explain fully.
- (b) Please explain, discuss and quantify the harm AESO customers will experience if the PSC is no longer an option for customers who own their own substations.
- (c) Please clarify the proposed treatment of the PSC eligibility; i.e. will the PSC be applied to “all system access services where the connection does not include conventional TFO-owned transformation facilities”, regardless if new or existing?
- (d) For each year from 2001 to 2009 please provide the total DTS revenue collected and the total PSC/COS revenue offset and the forecast 2010 DTS revenue and PSC revenue offset.

Response:

- (a) Confirmed, to the extent that the investment policy relates to all connection project facilities owned by a TFO, whether radial line or substation. (The AESO assumes that the mention of “local” refers to “local connection” costs rather than costs related to the “local system” function of the transmission system. The AESO’s investment policy does not apply to “bulk system” or “local system” costs, only to point of delivery (POD) costs.)
- (b) The AESO cannot quantify specific harm that may occur if the primary service credit is no longer optional for market participants who own their own substations. However, the AESO notes the following considerations.
 - (i) As discussed in the *Transmission O&M Cost Study* filed as Appendix C to the application, transmission lines and substations account for different amounts of operating and maintenance costs. The proposed Rate DTS is based on an average proportion of line and substation facilities — specifically, 21% (or less) line for an average connection project. When the TFO’s facilities for a connection project approach 100% line, as would be the case when the substation is owned

by a market participant, the full DTS rate will be misaligned with the operating and maintenance costs that will be incurred by the TFO, on average, with respect to the service.

- (ii) As part of the development of the Rate DTS investment level, the investment provided is compared to the cost of recent projects to assess whether the investment level is adequate in providing a sufficient amount of investment. Such a consideration should be equally applicable to connection projects under Rate PSC. Allowing the market participant to choose the higher Rate DTS investment level would likely result in a greater proportion of investment being provided in comparison to the TFO-owned facilities for such projects.
- (iii) The Rate DTS investment level is based on the cost of TFO-owned facilities. One reason a market participant would choose to build a substation could be that it is less expensive to do so than to have the TFO build it. If so, the Rate DTS investment level would be based on higher costs than the market participant would incur, and would therefore provide a greater proportion of investment than that available to market participants whose substations were built and owned by the TFO.

As a result of these considerations, the AESO finds it more consistent that the investment level and rate applicable to a service should be based on the TFO-owned facilities for that service. If a market participant chooses to build, own, and operate their own substation, then the investment level and rate should not be based on the assumption that the TFO owns the substation, which is the premise underlying the Rate DTS investment level and POD charge.

The AESO also comments that the proposed Rider I should allow a market participant to amortize a construction contribution that may be payable due to the lower investment under Rate PSC, and might therefore address concerns with the amount of contribution required.

- (c) The AESO does not propose to revisit a market participant's eligibility for or original choice with respect to the primary service credit. The proposed Rate PSC will apply to all existing market participants who are currently on that rate, and to all new system access services where the connection does not include conventional TFO-owned transformation facilities.
- (d) The AESO provides the requested quantities from 2003 to 2010 in the table below. Quantities for years prior to 2003 are not readily accessible.

Year	DTS Revenue	COS/PSC Credits
<i>Recorded</i>		
2003	\$321.1	(\$4.2)
2004	307.7	(5.3)
2005	365.6	(6.4)
2006	702.3	(6.2)
2007	742.7	(5.9)
2008	875.4	(6.5)
2009	682.3	(6.1)
<i>Forecast</i>		
2010	861.1	(6.5)

Topic: Amortized Construction Contribution Rider I

Reference: Section 4, Rate Design, Page 58 of 268

Preamble: The DUC wishes to better understand the proposed Rider I eligibility criteria and implementation details.

Request:

- (a) Please confirm that Rider I is proposed to be applicable for dual-use customers who currently own their own substations. If not confirmed, please explain fully.
- (b) Is the AESO proposing any eligibility provisions that would apply specifically to load, generation or dual-use customers in the application of Rider I? Please explain.
- (c) In paragraph 304 of the application it states: "The amount converted would be the balance which would have remained unamortized at the time of conversion ...". Please:
 - (i) Describe how and what records will be used to determine the unamortized construction contribution amount. Please provide an example.
 - (ii) Who will determine the unamortized construction contribution amount, the AESO or the TFO? Please explain.
 - (iii) Does the AESO foresee the need for the AUC to approve the unamortized construction contribution amount before a Rider I provision is implemented? Please explain.

Response:

- (a) Confirmed, for a construction contribution paid by the market participant for system access service.
- (b) The AESO is not proposing any eligibility provisions that would be specific to any subsets of market participants otherwise eligible for Rider I. Please refer to information response AE.AESO-001 (h) for additional information.
- (c) (i) The unamortized amount of the construction contribution would be determined in accordance with subsection 3(1)(b) of the Rider I rate sheet as the construction contribution "reduced by that fraction of the term...representing the number of years, in whole or in part, from the date of commercial operation to the first settlement period in which the ISO charges Rider I." Construction contributions and commercial operation dates would be those recorded for system access service agreements and tracked through the AESO's contract management processes.

Please refer to information response AE.AESO-001 (g) for an example.

- (ii) The AESO will determine the unamortized amount of the construction contribution in accordance with the terms of the Rider I rate sheet, as described in part (c)(i) above.
- (iii) The AESO does not expect the Commission will need to approve unamortized amounts of construction contributions that are determined in accordance with approved terms of the Rider I rate sheet. The Commission generally does not review charges billed in accordance with an approved rate or rider.

Topic: 2010 Forecast Billing Determinants

Reference: Section 4.19, 2010 Forecast Billing Determinants, Page 66 of 268, Table 4-12

Preamble: The 2010 Pool Price forecast of \$66.38/MWh is higher than the 2010 YTD average pool price. The AESO is forecasting a 15.1% reduction in billing determinants for the "All Remaining MW" POD rate block. The DUC requests additional information on historical forecast accuracy and the potential impact on the proposed tariff.

Request:

- (a) Please provide a table similar to Table 4-12 that compares the 2009 Forecast to the 2009 Actual billing determinants.
- (b) Please provide a table similar to Table 4-12 that compares the 2010 Forecast to the 2009 Actual billing determinants.
- (c) For each of the years 2005 to 2009, please provide the AESO's actual annual billing determinants for each of the categories noted in Table 4-12.
- (d) Please provide a detailed explanation for the 15.1% forecast reduction in MW-months billing determinants for the "All Remaining MW" block from the 2009 forecast.
- (e) For each of the years 2005 to 2009, please provide the AESO's annual average pool price forecast and the actual average annual pool price. Please also provide a discussion of the key reasons for any variances between the annual forecast and actual values.
- (f) Please explain what portions of the proposed DTS rate derivation (i.e. section 5 Tables) rely on the 2010 Pool Price Forecast.
- (g) Please explain and quantify the impact on the proposed DTS rates if the 2010 Pool Price forecast was \$10/MWh higher and \$10/MWh lower.
- (h) Please explain the source of the 2010 Pool Price forecast and how the forecast was derived.
- (i) Please explain the AESO's capability to forecast pool prices internally.

Response:

- (a) Please see Attachment DUC.AESO-007 (a).
- (b) Please see Attachment DUC.AESO-007 (b).

- (c) Please see Attachment DUC.AESO-007 (c).
- (d) Section 4.19 (page 66, paragraph 335) of the application discusses the 15.1% reduction from forecast 2009 to forecast 2010 for the MW-months in the highest billing capacity tier of “All Remaining MW.” A delay in peak demand growth occurred due to the world recession in 2009, which primarily affected the highest tier. A number of large oilsands extraction facilities and upgraders in northeast Alberta were delayed or deferred, and a number of chemical, forestry, and pulp and paper mill facilities also shut down or reduced production. Reduction in billing capacity for large projects primarily affects the highest billing capacity tier, and is reflected in a reduction of about 9% in that tier from forecast 2009 to recorded 2009, and a further reduction of about 7% in that tier from recorded 2009 to forecast 2010. (These reductions are provided in the attachments in parts (a) and (b) above, respectively.)

(e)

Year	Pool Price (Weighted by Volume), \$/MWh	
	Forecast	Recorded
2005	\$59.92	\$73.02
2006	\$41.93	\$84.01
2007	\$68.75	\$69.93
2008	\$84.81	\$92.96
2009	\$86.88	\$50.29

Pool price is determined through Alberta’s competitive wholesale market based on the principles of supply and demand. Pool price is low during instances of supply surplus and higher during times of supply scarcity. Pool price accordingly varies from forecast in response to factors that affect the supply-demand balance, such as weather and generating unit outages.

Pool price also reflects the price of offers submitted by generators. Prices will vary from forecast when the generators’ cost of fuel varies from forecast, such as when natural gas prices declined below forecast in 2009, and due to other factors.

- (f) Pool price is not used in the derivation of any of the primary charges in proposed Rate DTS.

In previous AESO tariffs, including the current tariff, pool price was used in the derivation of the operating reserve charge as an all-hours percentage of pool price. As discussed in section 4.4 (pages 35-38) of the application, the AESO proposes an hourly allocation of operating reserve costs in Rate DTS in the proposed tariff.

Pool price is used in the derivation of the “backup” operating reserve charge in subsection 4(2) of proposed Rate DTS. This charge will only be used in the event the operating reserve charge cannot be calculated as an hourly allocation of operating reserve costs in a settlement period, which is expected to occur rarely, if ever.

- (g) A change to the forecast pool price would not directly affect proposed Rate DTS as pool price is not used in the derivation of the primary charges in that rate, as discussed in part (f) above. However, a change to the pool price forecast would affect the forecast of

some components of the AESO's revenue requirement, and would therefore have an indirect effect on the charges which recover those costs.

Operating reserve costs primarily result from the competitive determination of prices through the active operating reserves market, which is structured such that operating reserve prices are indexed to pool price. This means that active operating reserve costs are directly related to pool price, and an increase or decrease in pool price would be expected to result in a proportional increase or decrease to operating reserve costs which would be allocated hourly to market participants under proposed Rate DTS.

Transmission must-run (TMR) costs are primarily procured through bilateral contracts where prices are dependent on the price of natural gas as well as on pool price. TMR costs are affected by pool price, but not as directly as active operating reserves. A change to forecast pool price would result in a change to forecast TMR costs, and the voltage control charge in proposed Rate DTS would change in proportion to the change in costs.

The operating reserve charge accounts for about 13% of the 2010 forecast revenue to be collected under Rate DTS, while the voltage control charge accounts for about 3% of the forecast revenue. A change of $\pm\$10.00/\text{MWh}$ represents a $\pm 15\%$ change to the forecast pool price of $\$66.38/\text{MWh}$, which would be expected to result in no more than a $\pm 2.4\%$ change ($15\% \times (13\% + 3\%)$) in average bills under Rate DTS.

- (h) Please refer to information response RDLE.AESO-001 (a).
- (i) The AESO has internal expertise that has been developed over several years to prepare forecasts in support of various responsibilities of the AESO, including system planning and market operations. That expertise is currently used in the review and utilization of external pool price forecasts where required in the AESO. The AESO considers that utilization of an independent, external pool price forecast as the basis for its ancillary service and losses cost forecasts continues to be appropriate.



Topic: Valuation of Facilities for Contribution Determination

Reference: Section 6.11.4, Page 116 of 268, Paragraphs 488-489

Preamble: Impact of TFO rate base with valuation of used assets based on replacement cost new (RCN). The seek clarity on proposed implementation.

Request:

Please confirm that the valuation of assets at RCN used for the application of section 8 of the proposed Terms and Conditions will not be used in the determination of the value of assets that are added or subtracted from a TFO's rate base. If not confirmed, please explain fully.

Response:

Confirmed. Please see information response CCA.AESO-012 (a-b) for additional information.

Topic: Electric Transmission Operating and Maintenance Cost Study

Reference: 2010-03-04 AESO 2010 ISO Tariff - Appendix C - Transmission O&M Cost Study and 2010-03-04 AESO 2010 ISO Tariff - Appendix D - Transmission O&M Cost Workbook.xls spreadsheet and Table 4-2

Preamble: There does not appear to be full consistency of values in the application with the values in the cost study report and worksheet.

Request:

- (a) Please confirm that the first 13 tabs in the 2010-03-04 AESO 2010 ISO Tariff - Appendix D - Transmission O&M Cost Workbook.xls spreadsheet (i.e. from tabs Key to Misc Rev) are not used in the determination of the cost study derivations or recommendations. If not confirmed, please explain fully.
- (b) Please compare the values presented in Table 1 of Appendix C Cost Study report, the values shown in the Appendix D spreadsheet tab Sum 4.0 and the values presented on Table 4-2 on page 30 or 268 of the application and provide a reconciliation. Please note any inconsistencies and verify the values used by the AESO in the development of the proposed DTS rate.
- (c) Please provide a derivation of the values used in lines 2 to 4 of Table 5-1, tab 5-1 DTS of spreadsheet 2010-03-04 AESO 2010 ISO Tariff - Section 5 - Rate Calculations.xls (i.e. how were the fixed constants in the spreadsheet formulas derived?).
- (d) Please provide a derivation of the Allocator % values used in lines 2 to 4 of Table 5-3, tab 5-3 DTS of spreadsheet 2010-03-04 AESO 2010 ISO Tariff - Section 5 - Rate Calculations.xls (i.e. how were the fixed constants in the spreadsheet formulas derived?).
- (e) Please provide a derivation of the Amount values used in lines 2 to 4 of Table 5-3, tab 5-3 DTS of spreadsheet 2010-03-04 AESO 2010 ISO Tariff - Section 5 - Rate Calculations.xls (i.e. how were the fixed constants in the spreadsheet formulas derived?).
- (f) Please explain why the year 2009 data was not used to determine the average percentage of the bulk, local and POD costs in rows 49-51 on tab Sum 3.0 of the spreadsheet 2010-03-04 AESO 2010 ISO Tariff - Appendix D - Transmission O&M Cost Workbook.xls.

Response:

- (a) Confirmed. All of the tabs prior to the Table of Contents (TOC) were earlier working papers and should not have accompanied the spreadsheet. All of the tabs listed in the

Table of Contents form Appendix A of the *Electric Transmission Operating and Maintenance Cost Study*.

An error occurred in AL Sch 5.1 in the number of elements (All:AL-8). The number of elements is correctly shown in Appendix A of the *Transmission O&M Cost Study* (Appendix C of the application). Other correction are included in the revised *Transmission O&M Cost Workbook* submitted with these IR responses, and are summarized at the bottom of the Table of Contents in the workbook.

- (b) Appendix D of the application is the source of the tables shown in Appendix C of the application, and has been corrected as explained in part (a) above.

Appendix D is also the source for Table 4-3, which is the table that appears on page 30 of the application. Table 4-3 in the application inadvertently included values from an earlier draft of the *Transmission O&M Cost Workbook*. A revised Table 4-3, based on the revised workbook discussed in part (a) above, is provided below.

Table 4-3 Functionalized and Classified Transmission System Non-Capital Costs (Revised), % of Total

Function	Total	Classification		
		Demand	Usage	Customer
Bulk System	16.1%	13.1%	3.0%	-
Local System	34.1%	24.5%	9.6%	-
POD	49.8%	17.1%	10.3%	22.3%
Total	100.0%	54.8%	22.9%	22.3%

Note: Totals may not add due to rounding

The table on page 30 of the application was provided only for reference in the text. Actual values from the *Transmission O&M Cost Workbook* were used in the rate calculations in section 5 of the application, as discussed in parts (c) and (d) below. Note that the rate calculations have been updated in the revised section 5 provided with these information responses.

- (c) The functionalized wires cost in lines 2 to 4 of Table 5-1 were calculated by:
- multiplying the total wires cost excluding the ATCO Electric isolated generation credit (from Table 2-2) by the functionalization percentages from the *Transmission O&M Cost Workbook* (Appendix D to the application), and
 - crediting the isolated generation credit to the local system and POD functions in the same proportion that isolated generation costs were apportioned to those functions in the *Transmission O&M Cost Study*.

The calculation based on the revised *Transmission O&M Cost Workbook* is provided as Attachment DUC.AESO-009 (c) and in the table below. The AESO notes that the section 5 rate calculations filed with the application inadvertently included values from an earlier draft of the *Transmission O&M Cost Workbook*. The rate calculations have been updated in the revised section 5 provided with these information responses.

Function	Wires Excluding Isolated Generation Credit	Isolated Generation Credit	Total Wires From Table 2-2 Line 16	
Wires Cost From Table 2-2, \$ 000 000				
Wires Cost	\$652.8	(\$4.4)	\$648.4	
Functionalization From Appendix D - Transmission O&M Cost Workbook (Revised), Sheet "Sum 4.0"				
Bulk System	34.4%	-		
Local System	22.2%	33.8%		
POD	43.5%	66.2%		
Totals	100.0%	100.0%		
Functionalized Wires Cost (Wires Cost × Functionalization)				
Bulk System	\$224.3	\$0.0	\$224.3	34.6%
Local System	144.7	(1.5)	143.2	22.1%
POD	283.7	(2.9)	280.9	43.3%
Totals	\$652.8	(\$4.4)	\$648.4	100.0%

- (d) The classification percentages on lines 2 to 4 of Table 5-3 were from the *Transmission O&M Cost Workbook* (Appendix D to the application), for all except the demand and customer classification of POD function costs. The classification from the revised *Transmission O&M Cost Workbook* is provided as Attachment DUC.AESO-009 (d) and is provided in the table below.

The classification percentages on lines 2 to 4 of Table 5-3 were calculated by:

- classifying the functionalized wires cost excluding the ATCO Electric isolated generation credit (as provided in part (c) above) by the functionalization percentages from the *Transmission O&M Cost Workbook* (Appendix D to the application), and
- classifying the functionalized isolated generation credit (as provided in part (c) above) as 100% usage-related, consistent with the classification of isolated generation costs in the *Transmission O&M Cost Study*.

The calculation based on the revised *Transmission O&M Cost Workbook* is provided as Attachment DUC.AESO-009 (d) and in the table below. The AESO notes that the section 5 rate calculations filed with the application inadvertently included values from an earlier draft of the *Transmission O&M Cost Workbook*. The rate calculations have been updated in the revised section 5 provided with these information responses.

As well, the classification of demand-related and customer-related POD costs based on the *Transmission O&M Cost Study* was replaced with the classification from the more detailed POD cost function analysis, as discussed in section 4.3.1 (pages 32-34) of the application. The derivation of the classification is provided on line 9 of Table 5-4 in section 5 of the application.

Function	Total	Classification		
		Demand	Usage	Customer
Classification From Appendix D - Transmission O&M Cost Workbook (Revised), Sheet "Sum 4.0"				
Bulk System	34.4%	28.0%	6.4%	-
Local System	22.2%	17.3%	4.9%	-
POD	43.5%	17.5%	3.2%	22.8%
Totals	100.0%	62.8%	14.4%	22.8%
Classification From Appendix D by Function (Classified Cost ÷ Function Total)				
Bulk System	100.0%	81.5%	18.5%	-
Local System	100.0%	77.9%	22.1%	-
POD	100.0%	40.2%	7.3%	52.5%
Totals	100.0%	62.8%	14.4%	22.8%
Classified Wires Cost Wires Excluding Isolated Generation Credit (From DUC.AESO-009 (c) × Classification by Function)				
Bulk System	\$224.3	\$182.8	\$41.5	-
Local System	144.7	112.7	32.0	-
POD	283.7	114.2	20.7	148.9
Totals	\$652.8	\$409.7	\$94.2	\$148.9
Classified Isolated Generation Credit (From DUC.AESO-009 (c) × 100% Usage-Related)				
Bulk System	-	-	-	-
Local System	(1.5)	-	(1.5)	-
POD	(2.9)	-	(2.9)	-
Totals	(\$4.4)	-	(\$4.4)	-
Total Classified Wires Cost Including Isolated Generation Credit				
Bulk System	\$224.3	\$182.8	\$41.5	-
Local System	143.2	112.7	30.6	-
POD	280.9	114.2	17.8	148.9
Totals	\$648.4	\$409.7	\$89.8	\$148.9
Total Classification by Function (Classified Cost ÷ Function Total)				
Bulk System	100.0%	81.5%	18.5%	-
Local System	100.0%	78.7%	21.3%	-
POD	100.0%	40.7%	6.3%	53.0%
Totals	100.0%	63.2%	13.9%	23.0%

- (e) The amounts in lines 2-4 of Table 5-3 reflect the DTS Amounts in column A of the table multiplied by the classification factors provided as the "Allocators" in columns B, D, F, and J of the table. The fixed constants result from the initial external links set up to apportion the isolated generation credit to the local system and POD functions, which were converted to fixed values when external links were removed from the workbook prior to filing section 5.

- (f) The 2009 data was not used because it was assessed as being no longer accurate since these forecasts were developed some time ago.

Topic: Electric Transmission Operating and Maintenance Cost Study

Reference: 2010-03-04 AESO 2010 ISO Tariff - Appendix C - Transmission O&M Cost Study and 2010-03-04 AESO 2010 ISO Tariff - Appendix D - Transmission O&M Cost Workbook.xls spreadsheet

Preamble: Clarification on the classification of AltaLink costs to capital and non-capital.

Request:

- (a) Under tab AI Sch 2.0 of spreadsheet 2010-03-04 AESO 2010 ISO Tariff - Appendix D - Transmission O&M Cost Workbook.xls please confirm that only a portion of the Total Miscellaneous Revenue was accounted for (e.g. for 2006 (column B), \$7,500,000 of \$9,862,478 or 76.0%). If not confirmed, please explain fully.
- (b) Under tab AI Sch 2.0 of spreadsheet 2010-03-04 AESO 2010 ISO Tariff - Appendix D - Transmission O&M Cost Workbook.xls please confirm that the portion of the Total Miscellaneous Revenue that was accounted for was classified as either capital or non-capital (e.g. for 2006 (column B), \$6,800,000 of \$7,500,000 or 90.7% classified as capital related). If not confirmed, please explain fully.
- (c) Under tab AI Sch 1.0 of spreadsheet 2010-03-04 AESO 2010 ISO Tariff - Appendix D - Transmission O&M Cost Workbook.xls please confirm that the portion of the Total Miscellaneous Revenue that was classified as capital equates to the portion of that was classified as capital on tab AI Sch 2.0 (e.g. for 2006 90.7% classified as capital related). If not confirmed, please explain fully.
- (d) Under tab AI Sch 3.0 of spreadsheet 2010-03-04 AESO 2010 ISO Tariff - Appendix D - Transmission O&M Cost Workbook.xls please confirm that only a portion of the Hearings, Self Ins and Other Taxes was accounted for (e.g. for 2006 (column B), \$13,400,000 of \$ 15,832,979 or 84.6%). If not confirmed, please explain fully.
- (e) Under tab AI Sch 3.0 of spreadsheet 2010-03-04 AESO 2010 ISO Tariff - Appendix D - Transmission O&M Cost Workbook.xls please confirm that the portion of the Hearings, Self Ins and Other Taxes that was accounted for was classified as either capital or non-capital (e.g. for 2006 (column B), \$13,300,000 of \$13,400,000 or 99.3% classified as capital related). If not confirmed, please explain fully.
- (f) Under tab AI Sch 1.0 of spreadsheet 2010-03-04 AESO 2010 ISO Tariff - Appendix D - Transmission O&M Cost Workbook.xls please confirm that the portion of the Hearings, Self Ins and Other Taxes that was classified as capital equates to the portion of that was classified as capital on tab AI Sch 3.0 (e.g. for 2006 99.3% classified as capital related). If not confirmed, please explain fully.

Response:

- (a) The actual and forecast Miscellaneous Revenue from 2006 for AltaLink is shown in the following table (as shown in AL Sch 2.0):

Revenue Source	Forecast	Actual
FortisAlberta	4,000,000	4,036,135
TransAlta Service Agreement	300,000	2,842,929
TransAlta Agreement General	500,000	376,995
Affiliate	200,000	158,451
Other Rev, Land and Com	2,500,000	2,447,968
Total	7,500,000	9,862,478

The forecast amounts are shown in AltaLink's 2009/2010 GTA at Section 4.3, and the actuals are from the same application in Schedule 4.2. The forecast data provides sufficient detail to determine if the revenue is capital related or non-capital related while the proportions are applied to the total amount. Sufficient detail is available only for a portion of the actual miscellaneous revenue.

- (b-f) Confirmed.

Topic: Electric Transmission Operating and Maintenance Cost Study

Reference: 2010-03-04 AESO 2010 ISO Tariff - Appendix C - Transmission O&M Cost Study and 2010-03-04 AESO 2010 ISO Tariff - Appendix D - Transmission O&M Cost Workbook.xls spreadsheet

Preamble: DUC seeks clarification on the derivation of some of the TFO Allocators. The allocators are based on fixed constants in the spreadsheet formulas without reference to supporting evidence.

Request:

- (a) Please provide the derivation and supporting evidence for the derivation of the “All:AL:5. Inventory (Property)” allocator as shown in rows 35-37 of Tab AL Sch 5.1 of spreadsheet 2010-03-04 AESO 2010 ISO Tariff - Appendix D - Transmission O&M Cost Workbook.xls.
- (b) Please provide the derivation and supporting evidence for the derivation of the “All:AL:6. Inventory (Property)” allocator as shown in rows 39-41 of Tab AL Sch 5.1 of spreadsheet 2010-03-04 AESO 2010 ISO Tariff - Appendix D - Transmission O&M Cost Workbook.xls.
- (c) Please provide the derivation and supporting evidence for the derivation of the “All:AL:7. Inventory (Property)” allocator as shown in rows 43-45 of Tab AL Sch 5.1 of spreadsheet 2010-03-04 AESO 2010 ISO Tariff - Appendix D - Transmission O&M Cost Workbook.xls.
- (d) Please provide the derivation and supporting evidence for the derivation of the “All:AL:9. Inventory (Property)” allocator as shown in rows 51-53 of Tab AL Sch 5.1 of spreadsheet 2010-03-04 AESO 2010 ISO Tariff - Appendix D - Transmission O&M Cost Workbook.xls.
- (e) Please provide the derivation and supporting evidence for the derivation of the “All:AL:10. Inventory (Property)” allocator as shown in rows 55-57 of Tab AL Sch 5.1 of spreadsheet 2010-03-04 AESO 2010 ISO Tariff - Appendix D - Transmission O&M Cost Workbook.xls.
- (f) Please provide the derivation and supporting evidence for the derivation of the “All:AT:4. Fuel (Displacement of Local and POD)” allocator as shown in rows 35-37 of Tab AT Sch 5.0 of spreadsheet 2010-03-04 AESO 2010 ISO Tariff - Appendix D - Transmission O&M Cost Workbook.xls.

Response:

- (a–e) Please refer to information response CCA.AESO-025 (a).

- (f) These property amounts were extracted from the *Transmission Cost Causation Study* that was part of the 2006 GTA. That study is provided as an attachment to information response AUC.AESO-001 (a).

Topic: Electric Transmission Operating and Maintenance Cost Study

Reference: 2010-03-04 AESO 2010 ISO Tariff - Appendix D - Transmission O&M Cost Workbook.xls spreadsheet tabs AL Sch 5.0, AL Sch 5.1, AL Sch 5.2, AL Sch 5.3 and AT Sch 5.0.

Preamble: DUC seeks information on the importance of each allocator.

Request:

- (a) For each of the AltaLink allocators All:AL:1 to All:AL:11 please provide a schedule that shows the total dollars and percentage of the total dollars allocated by each of the allocators.
- (b) Please describe the rationale for using the number of elements (lines and transformers) for the All:AL-8 allocator.
- (c) Please provide any evidence to support the use of the number of elements (lines and transformers) for the All:AL-8 allocator.
- (d) Please discuss the control centres costs and the functions the control centres provide for the transmission system for each TFO.
- (e) Please discuss if there are any differences between the types of lines or substations that could have an impact on control centre costs (e.g. maintenance switching for DFO substations, direct connect substations and customer owned substations) for each TFO.
- (f) Please provide, describe and evaluate any other potential options for the All:AL-8 allocator.
- (g) Please provide supporting evidence for the right of way widths used for the allocators All:AL:3 and All:AT:2.
- (h) Please discuss the appropriateness of using a narrower right of way width for lower voltage transmission lines that tend to be built on road allowances for the allocators All:AL:3 and All:AT:2.

Response:

- (a) The list of the dollar amounts for each allocator is shown below.

AltaLink Allocator	Description	2008 Amount
3	Line Brushing	\$4,907,673
4	Sub Brushing	\$300,000
6	Contract Manpower	\$9,944,125
7	EH&S	\$1,503,158
8	System Control Centre	\$6,313,262
9	Asset Management	\$4,659,789
10	Field Operations	\$7,515,788
11	Operational Services	\$1,954,105

- (b) Please refer to information response IPCAA.AESO-021.
- (c) Please refer to information response IPCAA.AESO-021.
- (d) The amount associated with system control centre operations for each of the four TFOs is shown in the following table:

TFO	2008 Amount
AltaLink	\$6,313,262
ATCO	\$1,900,000
ENMAX	\$1,885,074
EPCOR	\$562,840

- (e) The types of lines and substations that could impact control centre costs are lines and substations that are high maintenance. These substations would typically be substations that have circuit breakers connected to a large number of elements (lines and transformers) and, therefore, elements form the correct basis for increasing amounts of control centre time. Other equipment that impacts control centre costs would include lines that have no overhead shield wire (more trips due to lightning), which are typically older 69 kV lines. Equipment near the end of its service life may require more attention from the control centre as problems arise. Equipment such as gas-insulated switchgear (GIS) is more reliable than older technologies and would require less attention than average. In order to keep this study simple, factors including age, equipment type, etc. were not specifically taken into account when developing the element as the basis allocator for system control centre costs.
- (f) The development of the system control centre allocator was challenging because the operators work remotely from the equipment, and the equipment that they operate (primarily circuit breakers and transformer taps) provide service not directly related to the equipment being operated. The simplest allocator would be to allocate all of these costs to the various substations because all of the equipment that is operated is located within substations. This is not practical because circuit breakers are operated for a variety of reasons including taking equipment in and out of service, and tap changers are operated to maintain voltage within acceptable limits. Another potential allocator is the use of the number of lines and substations. Such an allocator would not address the differences of large substations with many elements comparison to simple substations that may have only one line termination.

- (g) A request was made of AltaLink and ATCO to provide their typical right of way widths and these TFOs provided this data. The typical right of way widths do not recognize the actual widths because this can vary line by line, and even within one line. The right of way width provides an indicator of the area that must be cleared of vegetation that may come in contact with electric transmission lines. Brushing contractors bid for work on the basis of area to be cleared, and therefore area is used as the allocator for brushing costs.

- (h) Lower voltage lines have narrower rights of way as shown in the *Transmission O&M Cost Study*. Lower voltage lines such as 69/72 kV and 138/144 kV may be built on road allowance which does reduce the width that must be cleared of vegetation. In order to keep the Study simple and easy to understand, typical right of way widths were used for all transmission lines.

Topic: Electric Transmission Operating and Maintenance Cost Study

Reference: 2010-03-04 AESO 2010 ISO Tariff - Appendix C - Transmission O&M Cost Study and Table 2-4, page 15 of 268

Preamble: DUC seeks additional information on the use of the 2007 GTA COSS

Request:

- (a) Please provide a copy of the 2007 GTA COSS (dated January 25, 2005?) referenced in Table 1 Summary Results including all related spreadsheets filed with the EUB during the 2007 GTA proceeding.
- (b) Please confirm that the 2007 GTA COSS was based on the assets that made up the AESO's 2003 wires revenue requirement of \$346.5 million. If not confirmed, please explain fully.
- (c) Please provide an estimate of the capital costs that have been added to the TFO rates bases since 2003 and segregate, as best as possible, into bulk, local and POD additions.
- (d) Please provide in electronic format (spreadsheets) each TFO applied for and the regulator approved schedules that show the following information for each TFO proceeding referenced in Table 2-4:
 - (i) Gross rate base
 - (ii) Net rate base
 - (iii) Capital additions
 - (iv) Complete listing of capital additions by project / type
 - (v) Accumulated Depreciation
 - (vi) Other expenses that make up the revenue requirement (return, income tax, O&M, A&G, etc.)

For clarity, the DUC is requesting the complete source spreadsheets prepared by each TFO for their application and the final regulator approved compliance filing (if applicable) for each TFO proceeding referenced in Table 2-4. The DUC anticipates that the requested source spreadsheets were publicly available on the EUB/AUC/ADOE websites; however, they may no longer be available and the DUC was not a registered party in any of the TFO proceedings.

If the AESO considers any of the requested information to be confidential, please forward to the DUC representative before April 12, 2010 a confidentiality agreement to allow this data to be provided to the DUC representative by May 5, 2010.

Response:

- (a) Please refer to information response AUC.AESO-001 for copies of both:
- the *Transmission System Wires Only Cost Causation Study* dated January 25, 2005 and filed as Appendix B to the AESO's 2006 tariff application, and
 - the *2006 Transmission Cost Causation Update* dated September 15, 2006 and filed as Appendix C to the AESO's 2007 tariff application.
- (b) Not confirmed. The cost causation studies did refer to the AESO's 2003 wires revenue requirement, but the studies examined TFO property, not revenue requirement. Please refer to information response IPCAA.AESO-15 (a) for the vintage of data in the original *Wires Only Cost Causation Study*.

The AESO's approved 2003 wires revenue requirement of \$346.5 million was based on approved 2003 TFO tariffs for AltaLink, ATCO Electric, ENMAX, and TransAlta, and interim tariffs which continued approved 2002 tariffs for EPCOR, Lethbridge, and Red Deer.

- (c) Please refer to information response TCE-Keystone.AESO-003 (b).
- (d) The AESO does not have the spreadsheets prepared by each TFO for the tariff applications referenced in Table 2-4. The AESO was not a registered participant in all the relevant proceedings. For the applied-for and approved amounts in the table, the AESO relied on the following decisions and orders of the Alberta Energy and Utilities Board and the Alberta Utilities Commission which approved the relevant tariffs.

TFO	Forecast Year	Decision or Order	Date	Proceeding
AltaLink	2007	2007-050	19 Jun 2007	AltaLink-TransAlta 2007-2008 TFO Tariff Refiling
AltaLink	2008	U2008-43	29 Jan 2008	AltaLink-TransAlta 2008 Revised TFO Tariff
ATCO Electric	2005	2006-070	11 Jul 2006	ATCO Electric 2005-2006 GTA Refiling
ATCO Electric	2006	2006-070	11 Jul 2006	ATCO Electric 2005-2006 GTA Refiling
ATCO Electric	2007	2007-104	21 Dec 2007	ATCO Electric 2007-2008 GTA Refiling
ATCO Electric	2008	2007-104	21 Dec 2007	ATCO Electric 2007-2008 GTA Refiling
ENMAX Power	2006	2006-130	21 Dec 2006	ENMAX 2006 TFO Tariff Refiling
EPCOR	2005	U2006-240	22 Sep 2006	EPCOR 2005-2006 TFO and Distribution Tariffs
EPCOR	2006	U2006-240	22 Sep 2006	EPCOR 2005-2006 TFO and Distribution Tariffs
EPCOR	2007	2008-125	3 Dec 2008	EPCOR 2007-2009 DT and TFO Tariffs

TFO	Forecast Year	Decision or Order	Date	Proceeding
EPCOR	2008	2008-125	3 Dec 2008	EPCOR 2007-2009 DT and TFO Tariffs
EPCOR	2009	2008-125	3 Dec 2008	EPCOR 2007-2009 DT and TFO Tariffs
Lethbridge	2007	U2006-47	24 Feb 2006	Lethbridge 2006-2008 TFO Tariff
Lethbridge	2008	U2006-47	24 Feb 2006	Lethbridge 2006-2008 TFO Tariff
Red Deer	2007	U2006-48	24 Feb 2006	Red Deer 2006-2008 TFO Tariff
Red Deer	2008	U2006-48	24 Feb 2006	Red Deer 2006-2008 TFO Tariff
TransAlta	2007	2007-050	19 Jun 2007	AltaLink-TransAlta 2007-2008 TFO Tariff Refiling
TransAlta	2008	U2008-43	29 Jan 2008	AltaLink-TransAlta 2008 Revised TFO Tariff

Topic: Electric Transmission Operating and Maintenance Cost Study

Reference: 2010-03-04 AESO 2010 ISO Tariff - Appendix C - Transmission O&M Cost Study and 2010-03-04 AESO 2010 ISO Tariff - Appendix D - Transmission O&M Cost Workbook.xls spreadsheet

Preamble: The DUC seeks clarification on the classification of G& A costs.

“This Study includes the functionalization and classification of O&M costs but does not study G&A costs. The G&A costs are functionalized and classified in the same proportion as O&M costs.” (s. 4.3.2, page 10)

Request:

- (a) Please explain fully the rationale for the functionalization of G&A costs for each TFO to bulk, local and POD using the same percentages derived in the cost study for O&M costs.
- (b) Please provide a revised 2010-03-04 AESO 2010 ISO Tariff - Appendix D - Transmission O&M Cost Workbook.xls spreadsheet with G&A costs functionalized to bulk, local and POD using the percentages from the 2007 GTA capital cost study (i.e. values presented in top section of Table 1 Summary Results for capital costs).
- (c) Please discuss the pros and cons of using the O&M cost vs. the capital cost allocators to functionalize G&A costs to bulk, local and POD. Please discuss any other allocators that could be reasonably used to functionalize G&A costs to bulk, local and POD.
- (d) Please discuss the rationale for treating cost of hearings, self insurance and business tax as non-capital (section 4.3.4, page 11).

Response:

- (a) Please refer to information response AUC.AESO-002.
- (b) Please refer to Attachment DUC.AESO-014 (b). The result of the assumption that G&A costs are treated in the same manner as capital costs is shown in the table below (extracted from Attachment DUC.AESO-014 (b)).

Weighted Capital and O&M	Bulk System	Local System	POD	Totals
Assuming G&A is Capital Related:DUC AESO 014b				
Demand Related	29.8%	16.5%	17.7%	64.0%
Energy Related	6.8%	4.2%	2.0%	13.0%
Customer (POD)	<u>0.0%</u>	<u>0.0%</u>	<u>23.0%</u>	<u>23.0%</u>
Totals	36.6%	20.7%	42.7%	100.0%

Weighted Capital and Non Capital	Bulk System	Local System	POD	Totals
Base Case				
Demand Related	28.1%	17.4%	17.7%	63.1%
Energy Related	6.4%	4.7%	2.7%	13.8%
Customer (POD)	<u>0.0%</u>	<u>0.0%</u>	<u>23.0%</u>	<u>23.0%</u>
Totals	34.5%	22.1%	43.4%	100.0%

- (c) The functionalization of G&A costs is a challenge because these costs are not directly linked to, nor proportional to O&M or capital costs. The G&A costs are, as the name implies, general and administrative. The arguments that G&A costs track capital costs include the argument that electric transmission systems are capital intensive, capital costs make up the majority of costs, and that G&A costs should therefore be functionalized in the same manner as capital costs. The arguments that G&A costs track O&M costs include the argument that all capital-related costs have been capitalized, and the remaining costs are primarily O&M. Therefore, the G&A costs should track the majority of non-capital costs, which are O&M costs. The conclusion arrived at in the *Transmission O&M Cost Study* is based on the latter view, that capital related costs are for the most part capitalized (exceptions are identified in the *Study*) and that G&A costs track the majority of the non-capital costs, which are O&M costs.

The three most apparent methods for functionalizing G&A costs include:

- allocation on the basis of O&M costs, as provided in Appendix D of the application,
 - allocation on the basis of capital costs, as provided above in Attachment DUC.AESO-014 (b), or
 - allocation on the basis of all other costs (O&M plus capital) as provided in the attachment to information request CCA.AESO-020.
- (d) The cost of hearings, self insurance, and business tax is treated as non-capital related because these costs are not linked to, and not proportional to, the capital costs of the electric transmission system. The cost of a hearing associated with a specific capital project is capitalized, and this cost will show up as a capital cost and is not included as a non-capital cost. The cost of hearings in this case relates to general applications (not facility applications) and therefore does not relate to any particular capital asset.

Topic: Electric Transmission Operating and Maintenance Cost Study

Reference: 2010-03-04 AESO 2010 ISO Tariff - Appendix C - Transmission O&M Cost Study and 2010-03-04 AESO 2010 ISO Tariff - Appendix D - Transmission O&M Cost Workbook.xls spreadsheet and 2010-03-04 AESO 2010 ISO Tariff - Appendix E - System RCN Multiplier.xls

Preamble: The DUC seeks clarification on the derivation of the Pre-Paid O&M percentages.

Request:

- (a) Please provide a discussion of the derivation for the 1.837 multiplier to estimate RCN from rate base provided on tab Summary of the spreadsheet 2010-03-04 AESO 2010 ISO Tariff - Appendix E - System RCN Multiplier.xls.
- (b) Please provide the source and a discussion on the selection of the inflation indices provided on tab inflation-index of the spreadsheet 2010-03-04 AESO 2010 ISO Tariff - Appendix E - System RCN Multiplier.xls.
- (c) Please compare and contrast the inflation indices provided on tab inflation-index of the spreadsheet 2010-03-04 AESO 2010 ISO Tariff - Appendix E - System RCN Multiplier.xls with the escalator values provided in tab escalator of spreadsheet 2010-03-04 AESO 2010 ISO Tariff - Appendix G - POD Cost Function Workbook.xls and explain why the same inflation indices were not used in both spreadsheets for the years in common.
- (d) Please provide the derivation and supporting evidence for the 6.0% discount rate used to derive the Pre-Paid O&M percentage (s. 6.1, page 21 and cell D14, tab Sum 5.0, spreadsheet 2010-03-04 AESO 2010 ISO Tariff - Appendix D - Transmission O&M Cost Workbook.xls).
- (e) For each of the years 1970 to 2010, please provide a table that shows the derivation of a taxable and non-taxable TFO discount rate using the formula contained in the AESO's Terms and Conditions (e.g. subsection 11 of section 8 of the proposed tariff). For clarity, the DUC is requesting an estimate of historical discount rates using historical yields on 30-year Government of Canada bonds and the forecast 2010 values for the variables E, ROE and T.
- (f) For each of the years 2000 to 2009 and a forecast for 2010, please provide a table that shows the derivation of a taxable and non-taxable TFO discount rate using the formulas contained in the AESO's Terms and Conditions for the tariff in effect each year (e.g. subsection 11 of section 8 of the proposed tariff for the year 2010). For clarity, the DUC is requesting an estimate of historical discount rates using historical yields on 30-year Government of Canada bonds and the actual values for the variables E, ROE and T (or similar variables used) from the tariff in effect each year from 2000 to 2009.

- (g) Please confirm that the Pre-Paid O&M percentage estimate provided under section 6.1.1 (page 21) assumes that all A&G costs are O&M related. If not confirmed, please explain fully.
- (h) Please confirm that the Pre-Paid O&M percentage estimate provided under section 6.1.2 (page 21) assumes that there are no economies of scale in adding incremental transmission assets, i.e. new assets will attract O&M expenses in direct proportion to the ratio of current O&M expenses to current capital assets valued at RCN. If not confirmed, please explain fully.
- (i) Please confirm that the Pre-Paid O&M percentage estimate provided under section 6.1.2 (page 21) assumes that O&M expenses are incurred proportionately over the life of the electrical asset, i.e. O&M costs are not lower when the asset is newer and greater as the asset ages. If not confirmed, please explain fully.

Response:

- (a) Please refer to information response TCE-Keystone.AESO-004 (k).
- (b) The inflation indices used in the derivation of the system RCN multiplier were Statistics Canada electric utility construction price indices applicable to the largest transmission property accounts filed in AltaLink's and ATCO Electric's depreciation studies. The indices measure the price change for construction of transmission lines (poles, towers, fixtures, overhead conductors, installation labour, engineering, and related costs) and substations (transformers, breakers, switchgear, support structures and fixtures, station buildings, meters, labour, engineering, and related costs). They are average annual Canada values as Alberta-specific values are not available. These indices were selected because they were applicable to the property accounts of the TFOs, publicly available, and Canadian.
- (c) The inflation indices used in the *POD Cost Function Workbook* were more specific than those used for the system RCN multiplier since costs were available in more detail for connection projects, with both transmission line and substation costs available by materials, construction, and engineering components. Some of the more detailed indices were also available in Alberta-specific versions. Both the POD cost function analysis and the system RCN multiplier analysis used publicly-available Statistics Canada indices.

It was not possible to use the more detailed indices for the system RCN multiplier analysis because detailed cost component data was not available for the vintaged surviving property balances for the TFO property accounts. Conversely, it would be inappropriate to use the more aggregate and Canada-wide indices for the POD cost function analysis when more detailed and Alberta-specific indices are available. In each case the most appropriate publicly-available indices were used.

- (d) The discount rate used for converting annual costs of O&M into a present value of O&M over 20 years was 6.0%. This discount rate is based on the assessment that 6.0% is a reasonable factor that would be applicable over the longer term (20 years). In real time, discount rates fluctuate with inflation, debt markets, and return on equity. Discount rates can be calculated with precision over historical periods, but discount rates for future periods will always be forecast. There will always be uncertainty as to the precise discount rate that will apply in the future.

Estimate of AESO Tariff Discount Rate 2000 - 2010								
ENMAX - TFO	Year	Equity Ratio	30 Yr Can Bonds	Approved ROE	Income Tax Rate	Discount Rate (Nom) (AESO Tar)	Inflation (Comp Price Index)	Discount Rate (Real)
	2000	N.A.	5.71%	N.A.	0.00%	N.A.	2.87%	N.A.
	2001	N.A.	5.76%	N.A.	0.00%	N.A.	4.11%	N.A.
	2002	N.A.	5.68%	N.A.	0.00%	N.A.	1.92%	N.A.
	2003	N.A.	5.34%	N.A.	0.00%	N.A.	-3.21%	N.A.
	2004	35%	5.14%	9.60%	0.00%	7.35%	4.81%	2.42%
	2005	35%	4.40%	9.50%	0.00%	6.84%	4.22%	2.51%
	2006	35%	4.28%	8.93%	0.00%	6.56%	6.77%	-0.20%
	2007	35%	4.32%	8.51%	0.00%	6.44%	8.02%	-1.46%
	2008	35%	4.05%	8.75%	0.00%	6.34%	8.86%	-2.32%
	2009	37%	3.90%	9.00%	0.00%	6.41%	-3.10%	9.82%
	2010	37%	3.90%	9.00%	0.00%	6.41%	2.26%	<u>4.06%</u>
	Average							2.12%

Estimate of AESO Tariff Discount Rate 2000 - 2010								
EPCOR - TFO	Year	Equity Ratio	30 Yr Can Bonds	Approved ROE	Income Tax Rate	Discount Rate (Nom) (AESO Tar)	Inflation (Comp Price Index)	Discount Rate (Real)
	2000	N.A.	5.71%	N.A.	0.00%	N.A.	2.87%	N.A.
	2001	N.A.	5.76%	N.A.	0.00%	N.A.	4.11%	N.A.
	2002	N.A.	5.68%	N.A.	0.00%	N.A.	1.92%	N.A.
	2003	N.A.	5.34%	N.A.	0.00%	N.A.	-3.21%	N.A.
	2004	35%	5.14%	9.60%	0.00%	7.35%	4.81%	2.42%
	2005	35%	4.40%	9.50%	0.00%	6.84%	4.22%	2.51%
	2006	35%	4.28%	8.93%	0.00%	6.56%	6.77%	-0.20%
	2007	35%	4.32%	8.51%	0.00%	6.44%	8.02%	-1.46%
	2008	35%	4.05%	8.75%	0.00%	6.34%	8.86%	-2.32%
	2009	37%	3.90%	9.00%	0.00%	6.41%	-3.10%	9.82%
	2010	37%	3.90%	9.00%	0.00%	6.41%	2.26%	<u>4.06%</u>
	Average							2.12%

Note:

Discount rate by TFO does not reflect each TFO's individual embedded cost of debt.

AltaLink started April 30, 2002. EPCOR and ENMAX came under AEUB jurisdiction in 2004.

Preferred equity is considered debt.

Estimated discount rate is calculated as per AESO tariff.

Income Tax rate from Canada Corporate Income Tax Rate Database

Discount rate shown is calculated as per AESO Tariff formula.

Forecast 2010 Long Term Canada bond is set at 2009 average.

Inflation is based on Composite Price Index developed by AESO.

- (g) Confirmed.
- (h) Confirmed.
- (i) Confirmed. The prepaid O&M charge is calculated on the basis of O&M costs associated with a mixture of old and new assets, and no age-based compensation is used.

Topic: DTS Rate Design

Reference: Table 5-6, Section 5 – 2010 Rate Calculations and 2010-03-04 AESO 2010 ISO Tariff - Appendix D - Transmission O&M Cost Workbook.xls

Preamble: The proposed DTS Local System Charge is proposed to increase 54% from \$653/MW-month to \$1,006/MW-month. This proposed increase is a key driver for the large price increases proposed for dual-use customers. The DUC would like to test the level of diversity that exists on 69 kV, 138 kV and 144 kV transmission lines that have been classified as either local or POD (i.e. see tab AL Sch 5.1 in spreadsheet 2010-03-04 AESO 2010 ISO Tariff - Appendix D - Transmission O&M Cost Workbook.xls).

Request:

- (a) Please provide justification and evidence the AESO has for proposing that the DTS Local System Billing Demand Charge should utilize DTS Billing Capacity as the billing determinant as opposed to other options including or a combination of DTS Coincident Metered Demand, DTS Billing Capacity or on-peak and off-peak demands.
- (b) Please discuss the AESO's understanding of the level of load and generation diversity that exists on 69 kV, 138 kV and 144 kV transmission lines.
- (c) Please discuss the AESO's understanding of the level of cost causation between 69 kV, 138 kV and 144 kV transmission line revenue requirement costs and DTS contract capacity and metered monthly demands.
- (d) For every 69 kV, 138 kV and 144 kV transmission line, please provide the AESO line identifier name, the 2009 hourly flow data in MVA and an indicator if the line has been classified as either local or POD by the AESO in an Excel spreadsheet(s). If the AESO does not have the data requested for each line, please provide all of the requested data that is available. If the AESO considers any of the requested information to be confidential, please forward to the DUC representative before April 12, 2010 a confidentiality agreement to allow this data to be provided to the DUC representative by May 5, 2010.
- (e) For every 69 kV, 138 kV and 144 kV transmission line, please provide the AESO line identifier name, the 2009 winter and summer line rating in MVA and the transmission line length in an Excel spreadsheet. If the AESO does not have the data requested for each line, please provide all of the requested data that is available. If the AESO considers any of the requested information to be confidential, please forward to the DUC representative before April 12, 2010 a confidentiality agreement to allow this data to be provided to the DUC representative by May 5, 2010.

- (f) For every substation, please provide the AESO substation identifier name, and the AESO line identifier name of the 69 kV, 138 kV and 144 kV lines that terminate at each substation in an Excel spreadsheet. If the AESO does not have the data requested for each substation, please provide all of the requested data that is available. If the AESO considers any of the requested information to be confidential, please forward to the DUC representative before April 12, 2010 a confidentiality agreement to allow this data to be provided to the DUC representative by May 5, 2010.
- (g) Please provide a set of revised Section 5 tables assuming that 50% of the demand related local revenue requirement is collected via a demand charge that uses DTS Coincident Metered Demand as the billing determinant and 50% of the demand related local revenue requirements is collected via a demand charge that uses DTS Billing Capacity as the billing determinant.

Response:

- (a) Billing capacity has been approved as the appropriate billing determinant for the recovery of local system costs since the AESO's current Rate DTS structure was first approved for 2006. In Decision 2005-096 on the AESO's 2005-2006 tariff application, the Alberta Energy and Utilities Board stated (page 28), "The demand charge for local and POD costs should be collected on the basis of non-coincident peak (NCP), including the use of a ratchet, as proposed by the AESO." The Board confirmed this approach in Decision 2007-106 (page 61) on the AESO's 2007 tariff application.

The local system charge recovers the cost of transmission facilities that deliver electricity from the bulk system to area loads. The local system facilities are generally designed to supply regional peak demand, which may not coincide with Alberta peak demand. As well, local system facilities are generally designed to provide system access service up to the contract capacity of market participants in the region under normal operating conditions. Billing capacity is therefore a reasonable determinant to use for the recovery of local system costs, as it includes considerations of contract capacity, current peak demand, and historical peak demand. The AESO notes that only 90% of contract capacity and only 90% of two-year historical peak demand are included when determining contract capacity, to provide some flexibility of operations to the market participant.

Using coincident metered demand (which is coincident with Alberta peak demand) would be inappropriate as the regional peak demand may not occur at the time of Alberta peak demand. Using on-peak and off-peak periods would not reflect that the local system must accommodate individual peak demands at any time of day. On balance, billing capacity is a reasonable basis for the local system charge.

- (b) As discussed in the *2006 Transmission Cost Causation Update* provided as an attachment to information response AUC.AESO-001 (b), "The further that you move from the POD to the Local System and into the Bulk System, the more diversity there is between loads and the diversity increases the difference between coincident load to maximum stress and maximum demand." (page 33) Load and generation diversity on the local system is therefore more of a consideration than for point of delivery facilities, but less of a consideration than for the bulk system. As discussed in the *AESO Long-Term Transmission System Plan 2009* provided as an attachment to information response AUC.AESO-021 (a), the regional planning process assesses the generation

scenario that is most onerous on the transmission system within a region and then evaluates impacts with re-dispatch of local generation. Local systems must frequently be able to accommodate generation-surplus, load-surplus, and balanced conditions at different times. Local system facilities must therefore be able to accommodate a variety of diversity patterns between load and generation in a region.

The AESO does not consider that there are significant differences in the local system function provided by 69 kV, 138 kV, and 144 kV transmission lines.

- (c) As discussed in part (a) above, local system facilities must be able to supply regional peak demand at any time and to provide system access service up to the contract capacity of market participants at any time. Contract capacities and peak metered demands therefore both cause costs on the transmission system.
- (d-f) Providing the requested information would be a larger undertaking than the bulk system data collection for the *2006 Transmission Cost Causation Update*, which itself took several months to assemble and validate. The AESO is therefore unable to provide the requested data in the time available for responses to information requests. The AESO also notes that the extensive data provided in the *2006 Transmission Cost Causation Update* ultimately had minimal impact on the final structure of the bulk system charge. The AESO suggests a clear scope and objectives should be developed before embarking on a similar undertaking to compile local system data.
- (g) Please see Attachment DUC.AESO-016 (g).