

Stakeholder Comments
AESO 2007 Rates Consultation
July 27, 2006

Written comments were received from:

ADC

ATCO Electric

EnCana

EPCOR

IPCAA

Kinder Morgan/Power Pipeline Group and Associates

Petro-Canada

Cities of Red Deer & Lethbridge

TransAlta

TransCanada

**AESO 2007 Rates Consultation
Discussion Paper — Stakeholder Comment Form**

Comments From: Alberta Direct Connect Consumers Association (ADC)
Date: July 11, 2006
Contact: Colette Kearn / Carrie Haines
Phone: (780) 920-9399 / (403) 770-1164
E-mail: Colette@valeopower.com / carrie@valeopower.com

2006 Transmission Cost Causation Update

1. The 17.1% local system and 41.9% point of delivery functionalization developed in the original *Transmission Cost Causation Study* should be retained. Support
 Oppose
 Indifferent

Reasons for Stakeholder Position: The AESO did not provide any evidence that would cause the ADC to dispute this particular finding.

2. Based on lack of correlation between transmission bulk line loading and total system load, it is more appropriate to recover demand-related bulk system costs through a \$/MW charge based on billing capacity. Support
 Oppose
 Indifferent

Reasons for Stakeholder Position: The ADC agrees that the planning and operational factors that require the need for transmission upgrades are demand related, i.e. they relate to an instantaneous loading on the lines. Consequently, the only relevant question is the timing of this critical demand. While the single hour of the AIL peak may not be perfect, there is no evidence that the time of an individual's peak load as measured at the POD is superior. Another reason for not using "billing capacity" is because that is a billing parameter over which the customer has little control, whereas the *time* of the customer's maximum demand *is* more controllable. Please also refer to the ADC's comment on Item No. 2 of the AESO 2006 Transmission Cost Causation Update Draft Report — Stakeholder Comment Form on Bulk System Demand Related Costs. Moreover, as noted on page 31 of the July 4 draft of the Transmission Cost Causation study, the interconnection ties were justified on the basis of substituting "peaking generation". Certainly, peaking generation is more related to coincident demand than it is to non-coincident demand.

3. The 80.7% adjustment to demand-related bulk system costs to reflect non-coincidence of POD load with bulk system maximum stress is appropriate, based on calculation at the time of maximum loading on each bulk line averaged for all bulk lines and weighted by line length. Support
 Oppose
 Indifferent

Reasons for Stakeholder Position: The ADC takes no position on the accuracy of the 80.7% figure, but does object to the manner in which the figure was interpreted and employed in the proposed rate design for DTS. It is clear that this 80.7% is a relationship between certain peak demands at different times. Consequently if the figure has any bearing on rate design, it would apply to the question of dividing cost recovery between coincident demand and non-coincident demand. Instead, the AESO appears to use this ratio to shift what are indisputably demand-related costs into the energy column. This is not a logical or supportable position.

4. It is appropriate to use the average cost function analysis to determine point of delivery cost classification of 40% demand-related and 60.0% customer-related. Support
 Oppose
 Indifferent

Reasons for Stakeholder Position: Based on the representations in the TCCS, this appears to be correct.

5. The proposed costs classification for 2007 rates presented in Figure 2 is appropriate, based on the analysis conducted and conclusions reached. Support
 Oppose
 Indifferent

Reasons for Stakeholder Position: The ADC cannot support the blurring of the distinction between Bulk System and Local System. The ADC believes that different factors, that is timing of demands, are involved in each system, and that the factors involving the Bulk System are more global and dynamic in nature, whereas the situation is more static for local lines. Moreover, as explained in the response to the point # 3 above, the ADC believes that Figure 2, which would recover almost 30% of system transmission costs on an energy basis (17.1% out of a total of 58.1%) significantly overstates the role of annual energy usage (other than for BTS or Opportunity service) and should not be used to recover DTS costs.

PODs Serving Smaller Loads

6. Rate GTS in the proposed rate schedules will be provided for services with DTS contract capacities of 5 MW or less as of January 1, 2006 and which are the sole service at a substation. Support
 Oppose
 Indifferent

Reasons for Stakeholder Position: The ADC would like to know the impact of this position on the rates of the DTS tariff before expressing an opinion. Assuming that the impact is not significant, this proposal appears reasonable. If the impact is significant, then we would question if 5 MW is the appropriate threshold for the rate.

Backup Transmission Service Rate

7. A rate with a \$/MWh System Charge equivalent to the DTS System Charge at 10% load factor and no POD Charge is an appropriate backup service for short-duration, infrequent use of the transmission system. Support
 Oppose
 Indifferent

Reasons for Stakeholder Position: This rate form appears to be harmonious with the mechanisms and approach typically found in backup rates and the ADC agrees that this is fair and reasonable.

Export and Import Rates

8. Rate XTS in the proposed rate schedules will be provided for non-recallable export transmission service. Support
 Oppose
 Indifferent

Reasons for Stakeholder Position: The ADC agrees that there should be special rate for exports, but at this time is not in a position to judge the adequacy of the charge proposed.

9.	Rates XOS 1 Hour and XOS 1 Month in the proposed rate schedules will be provided for export opportunity service.	<input checked="" type="checkbox"/> Support <input type="checkbox"/> Oppose <input type="checkbox"/> Indifferent
<p>Reasons for Stakeholder Position: The ADC supports opportunity service as a way to extract revenue from the system to the benefit of the firm users. The XOS rates should be priced comparatively with the same term DOS rates.</p>		

Merchant Export and Import Rates		
10.	Rates XTS, XOS 1 Hour, and XOS 1 Month be reduced by the share of costs attributable to the existing inter-ties when applied to service over merchant inter-ties.	<input type="checkbox"/> Support <input type="checkbox"/> Oppose <input type="checkbox"/> Indifferent
Reasons for Stakeholder Position:		

Primary Service Credit		
11.	The Primary Service Credit level should be increased to \$599.00/MW + (11,373.00/month × Substation Fraction) based on project costs analysis in the customer contribution policy study:	<input type="checkbox"/> Support <input type="checkbox"/> Oppose <input type="checkbox"/> Indifferent
Reasons for Stakeholder Position:		

Additional Comments		
<p>The ADC did not agree with the use of a minimum system approach to derive an energy-related component of lines in the previous TCCS. However, even if we accept that finding, those ostensible energy charges were to reduce line losses, which is chargeable to generation and not load. Consequently, the ADC does not believe that energy charges are an appropriate price signal to DTS customers.</p> <p>In the spirit of meaningful stakeholder consultation, it may have been worthwhile to delay the rate filing until all of the rates had been shared and discussed with stakeholders.</p>		

Please return this form with your comments by July 11, 2006, to:

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 Manager, Regulatory
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**AESO 2007 Rates Consultation
Discussion Paper — Stakeholder Comment Form**

Comments From: ATCO Electric
 Date: July 11, 2006
 Contact: Satar Parhar
 Phone: 780-420-5501
 E-mail: satar.parhar@atcoelectric.com

2006 Transmission Cost Causation Update	
<p>1. The 17.1% local system and 41.9% point of delivery functionalization developed in the original <i>Transmission Cost Causation Study</i> should be retained.</p>	<input type="checkbox"/> Support <input type="checkbox"/> Oppose <input type="checkbox"/> Indifferent
<p>Reasons for Stakeholder Position:</p>	
<p>2. Based on lack of correlation between transmission bulk line loading and total system load, it is more appropriate to recover demand-related bulk system costs through a \$/MW charge based on billing capacity.</p>	<input type="checkbox"/> Support <input checked="" type="checkbox"/> Oppose <input type="checkbox"/> Indifferent
<p>Reasons for Stakeholder Position:</p> <p>Please see section 2 of the Cost Causation Comment Form for ATCO Electric's reasons for opposing the billing capacity as the billing determinant for recovering the Bulk System related cost. ATCO Electric proposes to use energy as the billing determinant for this cost.</p>	
<p>3. The 80.7% adjustment to demand-related bulk system costs to reflect non-coincidence of POD load with bulk system maximum stress is appropriate based on calculation at the time of maximum loading on each bulk line averaged for all bulk lines and weighted by line length.</p>	<input type="checkbox"/> Support <input type="checkbox"/> Oppose <input type="checkbox"/> Indifferent
<p>Reasons for Stakeholder Position:</p>	
<p>4. It is appropriate to use the average cost function analysis to determine point of delivery cost classification of 40% demand-related and 60.0% customer-related.</p>	<input type="checkbox"/> Support <input type="checkbox"/> Oppose <input type="checkbox"/> Indifferent
<p>Reasons for Stakeholder Position:</p> <p>The contribution policy study data does not have any cost representation for small PODs (less than 5 MW). As such, the allocation of costs between customer and demand based on this data may not be appropriate, especially if the allocated cost are used in the determination for the fixed charges for small PODs. ATCO Electric notes that the AESO has proposed a \$/MW charge in lieu of fixed monthly charge for PODs serving less than 5 MW load. The approval of this proposal by the Board would significantly mitigate ATCO Electric's concerns in regards to the classification of the POD related costs.</p>	
<p>5. The proposed costs classification for 2007 rates presented in Figure 2 is appropriate, based on the analysis conducted and conclusions reached.</p>	<input type="checkbox"/> Support <input type="checkbox"/> Oppose

	<input type="checkbox"/> Indifferent
Reasons for Stakeholder Position:	

PODs Serving Smaller Loads	
6. Rate GTS in the proposed rate schedules will be provided for services with DTS contract capacities of 5 MW or less as of January 1, 2006 and which are the sole service at a substation. (g) Consider separating export and import facilities from domestic facilities.	<input checked="" type="checkbox"/> Support <input type="checkbox"/> Oppose <input type="checkbox"/> Indifferent
Reasons for Stakeholder Position:	
ATCO Electric supports the establishment of this rate for PODs serving loads less than 5 MW. These loads are served by potential transformers, notional PODs representing isolated communities and small non-standard transformers. These PODs have a cost function which is much different from that for the normal substations. The proposed \$/MW charge is a reasonable approach for recovering the customer related costs for these PODs.	

Backup Transmission Service Rate	
7. A rate with a \$/MWh System Charge equivalent to the DTS System Charge at 10% load factor and no POD Charge is an appropriate backup service for short-duration, infrequent use of the transmission system.	<input type="checkbox"/> Support <input type="checkbox"/> Oppose <input type="checkbox"/> Indifferent
Reasons for Stakeholder Position:	

Export and Import Rates	
8. Rate XTS in the proposed rate schedules will be provided for non-recallable export transmission service.	<input type="checkbox"/> Support <input type="checkbox"/> Oppose <input type="checkbox"/> Indifferent
Reasons for Stakeholder Position:	
9. Rates XOS 1 Hour and XOS 1 Month in the proposed rate schedules will be provided for export opportunity service.	<input type="checkbox"/> Support <input type="checkbox"/> Oppose <input type="checkbox"/> Indifferent
Reasons for Stakeholder Position:	

Merchant Export and Import Rates	
10. Rates XTS, XOS 1 Hour, and XOS 1 Month be reduced by the share of costs attributable to the existing inter-ties when applied to service over merchant inter-ties.	<input type="checkbox"/> Support <input type="checkbox"/> Oppose <input type="checkbox"/> Indifferent
Reasons for Stakeholder Position:	

Primary Service Credit

11. The Primary Service Credit level should be increased to \$599.00/MW + (11,373.00/month × Substation Fraction) based on project costs analysis in the customer contribution policy study:

- Support
 Oppose
 Indifferent

Reasons for Stakeholder Position:

Additional Comments

ATCO Electric believes that the pre-paid O&M is not a capital expenditure and should be treated as such. The pre-paid O&M should be identified as a separate cost item and should be used as an offset to reduce a TFO's O&M cost in the year the project is commissioned. With this approach, a TFO's rate base would not be reduced as a result of the customer contributions related to pre-paid O&M.

Please return this form with your comments by July 11, 2006, to:

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Comments From: EnCana Corporation
Date: July 11, 2006
Contact: Rod Crockford, Rinde Powell, Roger Belland
Phone: 403-645-7871, 403-645-6688, 780-486-4309
E-mail:

2006 Transmission Cost Causation Update

1. The 17.1% **local** system and 41.9% **point of delivery** functionalization developed in the original *Transmission Cost Causation Study* should be retained. Support
 Oppose
 Indifferent

Reasons for Stakeholder Position:

Please see “Additional Comments”.

In a fully considered and holistic rate design review, EnCana recommends that the AESO revisit the functionalization of costs between “Bulk”, “Local” and “POD”.

EnCana believes that there continues to be shortcomings with the measurement of costs (NBV vs replacement costs) as well as categorisation of functions (what function does the “local” 138 kV system provide in the SE and NW regions?). EnCana submits that the AESO should address these holistically rather than on a piecemeal basis, which will result in undue rate instability.

2. Based on lack of correlation between transmission bulk line loading and total system load, it is more appropriate to recover demand-related bulk system costs through a \$/MW charge based on billing capacity. Support
 Oppose
 Indifferent

Reasons for Stakeholder Position:

Please see “Additional Comments”.

The AESO and TCC-Update analysis appears to be focused on one objective – to disprove that coincident demand is correlated to the planning or causation of transmission expansions. The same data does not however lead to a default conclusion that billing capacity is correlated to the planning or causation of transmission expansions. Nor is billing capacity the only other definition of “demand”. Why has the AESO ignored any other definition or characterisation of demand?

EnCana submits that under the current market model, there is no singular identifiable moment that drives transmission stress and transmission planning for new expansions. This “diversity of moments” suggests that a holistic rate design review would consider various measures of demand using different time intervals including, on-peak periods, seasonal periods and all hours of the year as a fuller measure of the drivers of transmission expansions.

Put another way, the AESO has not yet addressed the “load factor” question. Under the AESO proposal

to recover demand-related bulk system costs through a \$/MW-billing capacity, two customers with opposing load factors would be charged the same for the bulk system usage. How does the AESO's information support the implication that a 10% load factor and a 90% load factor customer contribute equally to the cost causation of the bulk system?

3. The 80.7% adjustment to demand-related bulk system costs to reflect non-coincidence of POD load with bulk system maximum stress is appropriate, based on calculation at the time of maximum loading on each bulk line averaged for all bulk lines and weighted by line length.
- Support
 Oppose
 Indifferent

Reasons for Stakeholder Position:

Please see "Additional Comments".

Adjusting demand-related costs in this manner has no coherent reasoning and relevance to the association between transmission system usage and cost causation.

4. It is appropriate to use the average cost function analysis to determine point of delivery cost classification of 40% demand-related and 60.0% customer-related.
- Support
 Oppose
 Indifferent

Reasons for Stakeholder Position:

Please see "Additional Comments".

EnCana understands the AESO's proposal to use the information from the Contribution Policy Study, which was based on "replacement costs", to establish a classification between demand and energy related costs for purposes of classifying the NBV costs used in the Transmission Cost Causation update. EnCana is concerned that the use of different costs measures is not appropriate and further analysis is required to demonstrate that the proposal will not lead to systemic bias.

5. The proposed costs classification for 2007 rates presented in Figure 2 is appropriate, based on the analysis conducted and conclusions reached.
- Support
 Oppose
 Indifferent

Reasons for Stakeholder Position:

Please see "Additional Comments".

PODs Serving Smaller Loads

6. Rate GTS in the proposed rate schedules will be provided for services with DTS contract capacities of 5 MW or less as of January 1, 2006 and which are the sole service at a substation.
(g) Consider separating export and import facilities from domestic facilities.
- Support
 Oppose
 Indifferent

Reasons for Stakeholder Position:

Please see "Additional Comments".

EnCana is concerned with the AESO's proposal for "grandfathering" loads of less than 5 MW. If a rate class is to be created, then it should be based on cost-causation principles. Therefore, if the AESO has established that a distinct and identifiable cost function for sub-5 MW loads, then a distinct "rate class" and rate should be developed that reflects these costs and it should be open to old and new customers. If there is no distinct and identifiable sub-5 MW cost function, then there should not be a separate rate or rate class and there should not be a "grandfathered" rate.

Backup Transmission Service Rate

7. A rate with a \$/MWh System Charge equivalent to the DTS System Charge at 10% load factor and no POD Charge is an appropriate backup service for short-duration, infrequent use of the transmission system.
- Support
 Oppose
 Indifferent

Reasons for Stakeholder Position:

Please see "Additional Comments".

Export and Import Rates

8. Rate XTS in the proposed rate schedules will be provided for non-recallable export transmission service.
- Support
 Oppose
 Indifferent

Reasons for Stakeholder Position:

Please see "Additional Comments".

EnCana is not able to comment on a rate design that is not fully developed. The AESO needs to address capacity allocation, capacity hoarding and capacity reduction issues.

9. Rates XOS 1 Hour and XOS 1 Month in the proposed rate schedules will be provided for export opportunity service.
- Support
 Oppose
 Indifferent

Reasons for Stakeholder Position:

Merchant Export and Import Rates

10. Rates XTS, XOS 1 Hour, and XOS 1 Month be reduced by the share of costs attributable to the existing inter-ties when applied to service over merchant inter-ties.

- Support
 Oppose
 Indifferent

Reasons for Stakeholder Position:

Primary Service Credit

11. The Primary Service Credit level should be increased to \$599.00/MW + (11,373.00/month × Substation Fraction) based on project costs analysis in the customer contribution policy study:

- Support
 Oppose
 Indifferent

Reasons for Stakeholder Position:

The Primary Service Credit should be aligned with the POD Charges that are proposed for the DTS rate. If the POD charge portion of the DTS rate is based on the customer contribution policy study, then there will be alignment. However, if the POD portion is not based on the study, then it would be unfair to charge a customer on one basis and to credit them for avoided costs on a different basis. The Primary Service credit should credit the customer for avoided system costs as this would be reflected in the DTS rate.

Additional Comments

EnCana is increasingly concerned with the AESO's approach to reviewing and revising the transmission Cost Causation study. In EnCana's view, the AESO has not established a long-term vision as to the direction of the rate design and this makes it difficult to comment on the narrow aspects of the cost studies that are identified by the AESO.. This approach has the appearance that the AESO has already reached a rate design conclusion and is now only attempting to establish adequate popularity.

In EnCana's view, the AESO should be attempting to develop a rate design that is sustainable and predictable over the long-term. The cost causation and resulting rate design work has not achieved this requirement in the views of EnCana. As a result, EnCana is concerned that the AESO rate design will be subject to further "tweaking" and modification once again in the next GTA. EnCana submits that this is counter-productive as load consumers are unable to make dependable forecasts of the costs of using the transmission system and therefore create sound plans for future use. In EnCana's views, the AESO should take the time to respond to the Board's directive and to ensure that in responding it achieves a rate design that is sustainable. Until then EnCana does not believe that the AESO has adequately explained why it proposes the changes that it currently puts forward.

EnCana respectfully requests that the AESO re-consider its schedule and to delay the rate design application in order to address the holistic aspects of the design as discussed here.

Please return this form with your comments by July 11, 2006, to:

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**AESO 2007 Rates Consultation
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Comments From: EPCOR Utilities Inc.
Date: July 11, 2006
Contact: Richard Stout
Phone: (780) 412-3017
E-mail: rstout@epcor.ca

2006 Transmission Cost Causation Update	
<p>1. The 17.1% local system and 41.9% point of delivery functionalization developed in the original <i>Transmission Cost Causation Study</i> should be retained.</p>	<input type="checkbox"/> Support <input type="checkbox"/> Oppose <input checked="" type="checkbox"/> Indifferent
<p>Reasons for Stakeholder Position:</p>	
<p>2. Based on lack of correlation between transmission bulk line loading and total system load, it is more appropriate to recover demand-related bulk system costs through a \$/MW charge based on billing capacity.</p>	<input checked="" type="checkbox"/> Support <input type="checkbox"/> Oppose <input type="checkbox"/> Indifferent
<p>Reasons for Stakeholder Position: As explained in the Transmission Cost Causation Update, non-coincident demand related bulk system charges better reflect cost causation and are more appropriate. Furthermore, removing the AIS CP related charge simplifies the rate structure and settlement process by removing a determinant.</p>	
<p>3. The 80.7% adjustment to demand-related bulk system costs to reflect non-coincidence of POD load with bulk system maximum stress is appropriate, based on calculation at the time of maximum loading on each bulk line averaged for all bulk lines and weighted by line length.</p>	<input type="checkbox"/> Support <input type="checkbox"/> Oppose <input checked="" type="checkbox"/> Indifferent
<p>Reasons for Stakeholder Position: EPCOR cannot verify the calculation supporting the 80.7% adjustment to demand-related bulk system cost. EPCOR is, in general, supportive of a more broad-based demand allocator for the bulk system, for example “average of excess” or “top 50 hours peaks” as discussed in the June 14, 2006 technical meeting. However, the use of NCP demand is preferred over the CP demand as an allocator for the bulk system.</p>	
<p>4. It is appropriate to use the average cost function analysis to determine point of delivery cost classification of 40% demand-related and 60.0% customer-related.</p>	<input checked="" type="checkbox"/> Support <input type="checkbox"/> Oppose <input type="checkbox"/> Indifferent
<p>Reasons for Stakeholder Position:</p>	
<p>5. The proposed costs classification for 2007 rates presented in Figure 2 is appropriate, based on the analysis conducted and conclusions reached.</p>	<input type="checkbox"/> Support <input type="checkbox"/> Oppose <input checked="" type="checkbox"/> Indifferent
<p>Reasons for Stakeholder Position:</p>	

PODs Serving Smaller Loads

6. Rate GTS in the proposed rate schedules will be provided for services with DTS contract capacities of 5 MW or less as of January 1, 2006 and which are the sole service at a substation.
(g) Consider separating export and import facilities from domestic facilities.
- Support
 Oppose
 Indifferent

Reasons for Stakeholder Position: It would be EPCOR's preference that all customer classes be treated the same, but understand this to be a pragmatic solution.

Backup Transmission Service Rate

7. A rate with a \$/MWh System Charge equivalent to the DTS System Charge at 10% load factor and no POD Charge is an appropriate backup service for short-duration, infrequent use of the transmission system.
- Support
 Oppose
 Indifferent

Reasons for Stakeholder Position: EPCOR believes that the proposed BTS rate is in fact an opportunity service, not a standby or back-up rate, due to its interruptible and theoretically unplanned nature. EPCOR has no problem with the proposed rate if it is, in fact, identified as an opportunity rate, rather than a back-up rate. "Interruptible back-up" is an oxymoron that has been tried before in Alberta with predictably poor consequences. If the AESO intends to provide a back-up rate, there are better approaches, including the existing DTS tariff.

Export and Import Rates

8. Rate XTS in the proposed rate schedules will be provided for non-recallable export transmission service.
- Support
 Oppose
 Indifferent

Reasons for Stakeholder Position: EPCOR is unable to provide detailed comments on this proposal, but may provide feedback during the AESO's 2007 GTA proceeding.

9. Rates XOS 1 Hour and XOS 1 Month in the proposed rate schedules will be provided for export opportunity service.
- Support
 Oppose
 Indifferent

Reasons for Stakeholder Position: EPCOR is unable to provide detailed comments on this proposal, but may provide feedback during the AESO's 2007 GTA proceeding.

Merchant Export and Import Rates

10. Rates XTS, XOS 1 Hour, and XOS 1 Month be reduced by the share of costs attributable to the existing inter-ties when applied to service over merchant inter-ties.
- Support
 Oppose
 Indifferent

Reasons for Stakeholder Position: EPCOR is unable to provide detailed comments on this proposal, but may provide feedback during the AESO's 2007 GTA proceeding.

Primary Service Credit

11. The Primary Service Credit level should be increased to \$599.00/MW + (11,373.00/month × Substation Fraction) based on project costs analysis in the customer contribution policy study:
- Support
 Oppose
 Indifferent

Reasons for Stakeholder Position: EPCOR does not support this proposal. EPCOR believes that eligibility for the Primary Service Credit should not be dependent upon ownership of a substation. Rather, eligibility should be determined by the voltage at which a customer takes delivery of electricity. Customers who take delivery of electricity at 69kV or higher should be eligible for the Primary Service Credit, regardless of whether they own a substation or not as the AESO has avoided the cost of transformation in both cases. EPCOR takes no issue with the proposed calculation of the Primary Service Credit.

Additional Comments

Please return this form with your comments by July 11, 2006, to:

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**AESO 2007 Rates Consultation
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Comments From: IPCAA
 Date: July 10, 2006
 Contact: Ron Mikkelsen / Dan Macnamara
 Phone: (403) 263-3326 / 266-3180
 E-mail: consult@drazen.com / dmacnamara@shaw.ca

2006 Transmission Cost Causation Update

1. The 17.1% local system and 41.9% point of delivery functionalization developed in the original *Transmission Cost Causation Study* should be retained. Support
 Oppose
 Indifferent

Reasons for Stakeholder Position: IPCAA can accept the functionalization as it reflects the only information that is practically available.

2. Based on lack of correlation between transmission bulk line loading and total system load, it is more appropriate to recover demand-related bulk system costs through a \$/MW charge based on billing capacity. Support
 Oppose
 Indifferent

Reasons for Stakeholder Position: IPCAA is not satisfied that the demand measure should not reflect time of use, reflecting either peak, seasonal or time of use parameters. IPCAA would appreciate if the AESO would comment on the signals sent to loads through the tariff and the expected behavioural response, if any, of loads to the AESO tariff. Given that there are relatively few customers that have discretion to increase use in off peak periods, does the AESO feel it appropriate that the off-peak use of such customers should be the basis for allocating bulk transmission costs (i.e. through an NCP based tariff charge)? Have such conclusions been based on cost causation and examined in the TCCS?

3. The 80.7% adjustment to demand-related bulk system costs to reflect non-coincidence of POD load with bulk system maximum stress is appropriate, based on calculation at the time of maximum loading on each bulk line averaged for all bulk lines and weighted by line length. Support
 Oppose
 Indifferent

Reasons for Stakeholder Position: The proposed rate design appears inconsistent in that the 80% adjustment is proposed to reflect coincidence, in a fashion, yet the use of customer NCP (billing capacity) totally ignores coincidence.

4. It is appropriate to use the average cost function analysis to determine point of delivery cost classification of 40% demand-related and 60.0% customer-related. Support
 Oppose
 Indifferent

Reasons for Stakeholder Position: IPCAA agrees that it is appropriate to base the classification of POD costs on the most detailed information available. However, at this time, we are not prepared to endorse the AESO's interpretation of that cost data.

5. The proposed costs classification for 2007 rates presented in Figure 2 is appropriate, based on the analysis conducted and conclusions reached. Support
 Oppose

Indifferent

Reasons for Stakeholder Position: As noted under point 2, above, IPCAA does not agree that an NCP classification for bulk transmission is appropriate.

PODs Serving Smaller Loads

6. Rate GTS in the proposed rate schedules will be provided for services with DTS contract capacities of 5 MW or less as of January 1, 2006 and which are the sole service at a substation. Support
 Oppose
 Indifferent
 (g) Consider separating export and import facilities from domestic facilities.

Reasons for Stakeholder Position: IPCAA would like the AESO to present the different types of services under 5 MW (such as isolated generation, potential transformers, etc.) and indicate how many of the sites are "conventional" PODs under 5 MW. It would then be appropriate to comment as to whether the cost profile derived from the analysis of recent projects generally reflects the cost of these "conventional" facilities and, separately, explain why the customer/demand tariff would not be appropriate for each such POD.

Backup Transmission Service Rate

7. A rate with a \$/MWh System Charge equivalent to the DTS System Charge at 10% load factor and no POD Charge is an appropriate backup service for short-duration, infrequent use of the transmission system. Support
 Oppose
 Indifferent

Reasons for Stakeholder Position: It would be helpful for the AESO to examine how many existing DTS loads (if any) would be expected to make use of this service and to provide details as to how previous customer contributions (if any) would be reconciled. Do any such services also receive the Primary Service credit? If so, how would the tariff reflect this?

Export and Import Rates

8. Rate XTS in the proposed rate schedules will be provided for non-recallable export transmission service. Support
 Oppose
 Indifferent

Reasons for Stakeholder Position:

9. Rates XOS 1 Hour and XOS 1 Month in the proposed rate schedules will be provided for export opportunity service. Support
 Oppose
 Indifferent

Reasons for Stakeholder Position:

Merchant Export and Import Rates

10. Rates XTS, XOS 1 Hour, and XOS 1 Month be reduced by the share of costs attributable to the existing inter-ties when applied to service over merchant inter-ties. Support
 Oppose
 Indifferent

Reasons for Stakeholder Position:

Primary Service Credit

11. The Primary Service Credit level should be increased to \$599.00/MW + (11,373.00/month × Substation Fraction) based on project costs analysis in the customer contribution policy study:
- Support
 Oppose
 Indifferent

Reasons for Stakeholder Position: It is appropriate for the AESO to align the Primary Service credit with the DTS tariff.

Additional Comments

Please return this form with your comments by July 11, 2006, to:

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**AESO 2007 Rates Consultation
Discussion Paper — Stakeholder Comment Form**

Comments From: (KMC) Kinder Morgan Canada Inc./ Power Pipeline Group and Associates (PPGA)

Date: July 14, 2006

Contact: Neall Banner, Ed de Palezieux, Jamie Shand, Colin Carlsen

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2006 Transmission Cost Causation Update

1. The 17.1% local system and 41.9% point of delivery functionalization developed in the original *Transmission Cost Causation Study* should be retained. Support
 Oppose
 Indifferent

Reasons for Stakeholder Position:

In the 2006 tariff proceeding, Arnie Reimer stated that the allocation of all radial line and substation costs to the POD category needs to be revisited since the high side costs – such as breakers and switch gear, would more properly categorized as a local cost. While this reclassification may be difficult, an expert should be retained to estimate this cost. It does not seem reasonable to state that these costs are relatively small without a more thorough analysis of the costs. This expert estimate should be used to better allocate costs between the POD and local categories. KMC is supportive of the AESO estimating this cost allocation in order to improve the integrity of the POD/ Local cost split.

In the original cost causation report, EPCOR and ENMAX (the Cities) provided PS Technologies with a total cost for all substations – not by each individual substation. PS Technologies therefore placed the entire amount of substations for the Cities in the POD category and did not allocate any of the substation costs to the local grouping. The percent of costs allocated to the POD categories was 68.3% in the Cities, while averaging only 32.2% in ATCO and Altalink territories, highlighting the inconsistency of the data. Given that the Cities were not able to provide a similar cost breakdown as ATCO and Altalink, it appears questionable to include the entire cost of the Cities substations in the POD category. KMC recommends the POD/ Local cost split be adjusted to the average of ATCO/Altalink POD/Local split (i.e. 32%), given the inadequate data breakdown provided by the Cities.

2. Based on lack of correlation between transmission bulk line loading and total system load, it is more appropriate to recover demand-related bulk system costs through a \$/MW charge based on billing capacity. Support
 Oppose
 Indifferent

Reasons for Stakeholder Position:

3. The 80.7% adjustment to demand-related bulk system costs to reflect non-coincidence of POD load with bulk system maximum stress is appropriate based on calculation at the time of maximum loading on each bulk line averaged for all bulk lines and weighted by line length. Support
 Oppose
 Indifferent

Reasons for Stakeholder Position:

4. It is appropriate to use the average cost function analysis to determine point of delivery cost classification of 40% demand-related and 60.0% customer-related. Support
 Oppose
 Indifferent

Reasons for Stakeholder Position:

It is not reasonable to create a large increase in costs to certain customers based upon a cost function that draws its conclusions from low correlation factors between key variables. While the investment function must be created in determining system contribution for future projects, despite the relatively low correlation between data points, it is not reasonable to use a low correlation to, in some cases, increase customer tariff costs by over 200% per year.

KMC believes that the analysis conducted by the AESO is prejudiced against smaller than average size transmission customers. It is KMC's experience that larger sized transformers are more expensive than smaller sized transformers. The PS Technologies analysis does not break down the POD's by physical asset size, before assessing an appropriate y-intercept and fixed customer cost. Likewise the new partial POD data used by the AESO does not have an adequate number of data points to breakdown the POD costs into appropriate groupings to reflect or differentiate between different facility sizes – such as less than 10 MVA, 11 – 25 MVA, 26-50 MVA, etc.

A number of methods could be used to create a POD charge that more accurately reflects the actual costs to each customer class; however to simplify matters, KMC is also supportive of modifying the proposed GTS rate design in order to address this issue. Please see comments under question 6.

5. The proposed costs classification for 2007 rates presented in Figure 2 is appropriate, based on the analysis conducted and conclusions reached. Support
 Oppose
 Indifferent

Reasons for Stakeholder Position:

PODs Serving Smaller Loads

6. Rate GTS in the proposed rate schedules will be provided for services with DTS contract capacities of 5 MW or less as of January 1, 2006 and which are the sole service at a substation.
(g) Consider separating export and import facilities from domestic facilities. Support
 Oppose
 Indifferent

Reasons for Stakeholder Position:

KMC is generally supportive of the GTS rate proposal. However, KMC is not supportive of the current 5 MW or less cutoff for this type of service.

KMC believes that a key reason for creating the GTS rate class is to moderate the rate shock, or rate impact, to smaller load customers. Many customers above 5 MW experienced rate shock of over 200%. It is KMC's opinion that the current 5 MW limit is unfair and rather arbitrary and that better methods exist to determine the proper cut-off level for the GTS service.

One method of setting the GTS limit is to base it on the average size of transformers. Smaller loads require less costly, smaller transformers. The AESO's rate making methodology, creating one POD charge instead of several distinct POD charges (based upon transformer size) does not properly reflect the principles of cost/ causation. An improved method is to create different POD cost groups, based upon Transformer size. The AESO does not appear to have adequate data to properly calculate POD charges in this manner. To rectify this situation KMC suggests that the AESO increase the customers eligible for GTS service to 25 MVA (the approximate average size transformer in the province). This will reduce the POD charge burden to smaller customers, creating a closer alignment between the POD charge and the principles of cost causation.

A second method of determining a more appropriate cut-off for GTS rate class recognizes that many customers chose transmission over distribution service. KMC believes that industrial transmission customers that made a choice between distribution and transmission service, before implementation of the POD charge, should be included in the GTS rate class.

The largest standard size transformer used on the distribution system is 16.7 MVA. Industrial customers with a peak load of less than 16.7 MVA, in many cases, may select between transmission and distribution (T vs. D) service. The tariff of the day will determine the level of system investment for each type of service, and customers make the T vs. D selection based upon the capital cost of each type of service (transmission and distribution) operating tariff costs, required level of reliability and requirements for future growth. Therefore, another alternative is to set the cut-off for GTS service at the highest load customer that may have chosen transmission over distribution service, or 16.7 MVA.

Finally, the POD data analysis does not recognize that smaller load transmission level customers rarely require an interconnection at 138 kV. However, the TFO's in Alberta have adopted 138 kV as the minimum standard transmission voltage. While this standard saves the system funds by minimizing parts inventories, minimizing system losses and reducing operating, and maintenance charges, it ends up costing smaller customers higher costs for their interconnections. It is estimated by KMC that smaller load transmission customers could pay up to 30% more for their interconnections that would be necessary if they could have connected at a lower voltage level, such as 69 kV. AESO rates do not consider this extra cost burden faced by smaller load customers, creating another reason to grant smaller load customers access to a staged GTS rate of 25 MVA.

It is reasonable to assume that most industrial customers did not believe they would face a large increase in tariff costs when they chose to connect to the transmission system. It seems unreasonable to increase tariff charges to these customers by over 200% when the customers have already sunk capital into a Transmission service and made term commitments to their resulting DTS contracts. These customers now face limited opportunity to change their type of service to mitigate tariff cost increases.

KMC believes that the definition of a GTS eligible customer should be expanded to include industrial loads over 5 MW but below 16.7 MVA or 25 MVA. Can the AESO please assess the POD costs applicable to customers if the allowable GTS limit was increased to 16.7 or 25 MVA?

Backup Transmission Service Rate

7. A rate with a \$/MWh System Charge equivalent to the DTS System Charge at 10% load factor and no POD Charge is an appropriate backup service for short-duration, infrequent use of the transmission system.
- Support
 Oppose
 Indifferent

Reasons for Stakeholder Position: The Back-up rate proposed by the AESO needs further analysis. Not enough time or detail has been given to KMC or other customers for analysis and due diligence.

The AESO predicts that over 4000 MW of customer billing capacity may utilize this rate. Based upon this type of usage, what is the expected impact on other customers on the system? How will the POD charge be impacted? How will the system recover the Bulk system investment that was made to provide service to these customers?

Export and Import Rates

8. Rate XTS in the proposed rate schedules will be provided for non-recallable export transmission service.
- Support
 Oppose
 Indifferent

Reasons for Stakeholder Position:

9. Rates XOS 1 Hour and XOS 1 Month in the proposed rate schedules will be provided for export opportunity service.
- Support
 Oppose
 Indifferent

Reasons for Stakeholder Position:

Merchant Export and Import Rates

10. Rates XTS, XOS 1 Hour, and XOS 1 Month be reduced by the share of costs attributable to the existing inter-ties when applied to service over merchant inter-ties.
- Support
 Oppose
 Indifferent

Reasons for Stakeholder Position:

Primary Service Credit

11. The Primary Service Credit level should be increased to \$599.00/MW + (11,373.00/month × Substation Fraction) based on project costs analysis in the customer contribution policy study:
- Support
 Oppose
 Indifferent

Reasons for Stakeholder Position:

The Primary Service credit rate proposed by the AESO properly compensates customers for the construction and maintenance of their transformation equipment. KMC is therefore supportive of this proposal.

Additional Comments

Please return this form with your comments by July 11, 2006, to:

John Martin
Manager, Regulatory
E-mail: john.martin@ieso.ca
Phone: (403) 539-2465
Fax: (403) 539-2524

**AESO 2007 Rates Consultation
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Comments From: Desiderata Energy Consulting Inc (for Petro-Canada)
 Date: July 12, 2006
 Contact: Dale Hildebrand
 Phone: 403-869-6200
 E-mail: dale.hildebrand@desiderataenergy.com

2006 Transmission Cost Causation Update

1. The 17.1% local system and 41.9% point of delivery functionalization developed in the original *Transmission Cost Causation Study* should be retained. Support
 Oppose
 Indifferent

Reasons for Stakeholder Position:

2. Based on lack of correlation between transmission bulk line loading and total system load, it is more appropriate to recover demand-related bulk system costs through a \$/MW charge based on billing capacity. Support
 Oppose
 Indifferent

Reasons for Stakeholder Position:

3. The 80.7% adjustment to demand-related bulk system costs to reflect non-coincidence of POD load with bulk system maximum stress is appropriate, based on calculation at the time of maximum loading on each bulk line averaged for all bulk lines and weighted by line length. Support
 Oppose
 Indifferent

Reasons for Stakeholder Position:

4. It is appropriate to use the average cost function analysis to determine point of delivery cost classification of 40% demand-related and 60.0% customer-related. Support
 Oppose
 Indifferent

Reasons for Stakeholder Position:

5. The proposed costs classification for 2007 rates presented in Figure 2 is appropriate, based on the analysis conducted and conclusions reached. Support
 Oppose
 Indifferent

Reasons for Stakeholder Position:

PODs Serving Smaller Loads

6. Rate GTS in the proposed rate schedules will be provided for services with DTS contract capacities of 5 MW or less as of January 1, 2006 and which are the sole service at a substation.
 (g) Consider separating export and import facilities from domestic facilities. Support
 Oppose
 Indifferent

Reasons for Stakeholder Position:

Backup Transmission Service Rate

7. A rate with a \$/MWh System Charge equivalent to the DTS System Charge at 10% load factor and no POD Charge is an appropriate backup service for short-duration, infrequent use of the transmission system.
- Support
 Oppose
 Indifferent

Reasons for Stakeholder Position:
Allows for low load factor usage of transmission system and for appropriate planning of transmission system. Good initiative.

Export and Import Rates

8. Rate XTS in the proposed rate schedules will be provided for non-recallable export transmission service.
- Support
 Oppose
 Indifferent

Reasons for Stakeholder Position:

9. Rates XOS 1 Hour and XOS 1 Month in the proposed rate schedules will be provided for export opportunity service.
- Support
 Oppose
 Indifferent

Reasons for Stakeholder Position:

Merchant Export and Import Rates

10. Rates XTS, XOS 1 Hour, and XOS 1 Month be reduced by the share of costs attributable to the existing inter-ties when applied to service over merchant inter-ties.
- Support
 Oppose
 Indifferent

Reasons for Stakeholder Position:

Primary Service Credit

11. The Primary Service Credit level should be increased to \$599.00/MW + (11,373.00/month × Substation Fraction) based on project costs analysis in the customer contribution policy study:
- Support
 Oppose
 Indifferent

Reasons for Stakeholder Position:
Since the EUB has determined that investment policy should be cost based instead of revenue based it makes sense to tie the PSC to the costs.

Additional Comments

Please return this form with your comments by July 11, 2006, to:

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July 11, 2006

John Martin
Alberta Electric System Operator
2500, 330 – 5 Ave SW
Calgary, AB T2P 0L4

Dear Mr. Martin

SUBJECT: AESO 2006 Cost of Service Update

In response to your July 4th draft entitled “2006 Transmission Cost Causation Update,” I am responding on behalf of the Cities of Red Deer and Lethbridge to your invitation for comment. The Cities recognize the AESO’s continued efforts to improve the accuracy and credibility of the cost causation study. Based on the AESO’s comments, it may be faced with data limitations beyond its control, which may lead to a less than ‘perfect’ tariff proposal in the upcoming 2007 GTA.

Should the AESO’s study be approved by the Board in a 2007 GTA for ratemaking purposes, our concern is that the AESO might conclude that the matter is resolved. We therefore recommend that the AESO include credible assurances in its 2007 GTA that it will continue long-term efforts to address the data deficiencies identified to date.

Sincerely,

<sent by email>

Nigel Chymko
President

2006-07-11 AESO 2007 Rates Consultation - TransAlta Comments.txt

From: Bob_Smith@TransAlta.com
Sent: Tuesday, July 11, 2006 2:15 PM
To: John Martin
Subject: 2007 Rates and T&Cs

John

TransAlta has no significant comments to make with respect to both the proposed rates and Terms and Conditions sent to us on June 27, 2006. Our one concern relates to the apparent need to continually change the rate structure of the DTS rate. The lack of correlation between bulk line loading and total system load, in itself, should not be reason enough to change back to charges based on billing capacity. Rate stability should also be a consideration in the final determination of the rate structure.

Bob Smith, P. Eng.
Manager, Regulatory Affairs
TransAlta
(403) 267-7119

**AESO 2007 Rates Consultation
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Comments From: TransCanada Energy Ltd.
 Date: July 11, 2006
 Contact: Cheryl Terry / Dan Levson
 Phone: 920-2092 / 920-2095
 E-mail: Cheryl_Terry@TransCanada.com / Dan_Levson@TransCanada.com

2006 Transmission Cost Causation Update	
<p>1. The 17.1% local system and 41.9% point of delivery functionalization developed in the original <i>Transmission Cost Causation Study</i> should be retained.</p>	<input type="checkbox"/> Support <input checked="" type="checkbox"/> Oppose <input type="checkbox"/> Indifferent
<p>Reasons for Stakeholder Position: TransCanada remains concerned about the fundamental flaw in the cost of service study where the AESO has assumed that the sum of the RGUC Charges from the PPA generation (i.e. a revenue stream) are totalled and then deducted from the transmission costs as if they are an accurate reflection of the costs associated with interconnecting the PPA generators to the transmission system. The most current evidence provided by the AESO indicates the sum of the RGUCC is significantly different from the best estimate of the actual interconnection costs for PPA generation. The AESO should either use its most current estimate of these interconnection costs or improve their accuracy and submit that new cost analysis. In other words, the AESO should not use a revenue stream derived from a rate or a part of a rate as a proxy for costs. The AESO's \$11.9 million estimate of interconnection costs associated with regulated generating units is found in Exhibit 02-033-005, TCE-AESO-251(d) revised from the 2006 AESO GTA. Regardless of whether the AESO is prepared to recommend a change to the RGUCC, the cost study should not be distorted by this approach.</p>	
<p>2. Based on lack of correlation between transmission bulk line loading and total system load, it is more appropriate to recover demand-related bulk system costs through a \$/MW charge based on billing capacity.</p>	<input type="checkbox"/> Support <input checked="" type="checkbox"/> Oppose <input type="checkbox"/> Indifferent
<p>Reasons for Stakeholder Position: The reasons TransCanada is opposed to this approach are set out in a separate attachment to this document that will be provided shortly.</p>	
<p>3. The 80.7% adjustment to demand-related bulk system costs to reflect non-coincidence of POD load with bulk system maximum stress is appropriate, based on calculation at the time of maximum loading on each bulk line averaged for all bulk lines and weighted by line length.</p>	<input type="checkbox"/> Support <input checked="" type="checkbox"/> Oppose <input type="checkbox"/> Indifferent
<p>Reasons for Stakeholder Position: TransCanada is opposed to this adjustment since it is opposed to moving to the use of billing demand to charge for the demand-related bulk system costs as described in the previous question. More details will be provided in a separate document to be provided shortly.</p>	
<p>4. It is appropriate to use the average cost function analysis to determine point of delivery cost classification of 40% demand-related and 60.0% customer-related.</p>	<input type="checkbox"/> Support <input checked="" type="checkbox"/> Oppose <input type="checkbox"/> Indifferent

Reasons for Stakeholder Position: TransCanada has raised concerns about the accuracy of the data used in the review of projects completed to 1999 to 2005. The validity of a 40% demand-related and 60% customer-related split cannot be substantiated without these concerns being addressed. Details of the concerns are provided in a separate letter to the AESO.

5. The proposed costs classification for 2007 rates presented in Figure 2 is appropriate, based on the analysis conducted and conclusions reached.

Support
 Oppose
 Indifferent

Reasons for Stakeholder Position: Since the cost classifications described in Figure 2 are based on analysis provided in items discussed above, TransCanada cannot endorse these cost classifications until the other matters are resolved.

PODs Serving Smaller Loads

6. Rate GTS in the proposed rate schedules will be provided for services with DTS contract capacities of 5 MW or less as of January 1, 2006 and which are the sole service at a substation.
(g) Consider separating export and import facilities from domestic facilities.

Support
 Oppose
 Indifferent

Reasons for Stakeholder Position: TransCanada can see merit in splitting smaller PODs into a separate rate class as long as the rate design, cost of service and investment policies are aligned within the new rate class. When creating a new rate class, it is also necessary to revisit the costs, rate design and investment policy for the former rate class (i.e. Rate DTS) to ensure that is aligned given its new configuration. The AESO does not appear to have completed this work and therefore TransCanada cannot endorse this rate as yet. Also, TransCanada opposes treating this rate class on a grandfathered basis (i.e. only PODs with contract capacities of 5 MW or less as of January 1, 2006). If Rate GTS is properly designed, there should be no need to grandfather the rate. If the rate is properly designed, it will address the issues raised by the AESO in paragraphs (a) through (d) on page 7. Furthermore, a small customer wanting to attach to the system in the future would face material discrimination in its charges compared to similar customers with similar load characteristics on Rate GTS. The lack of such new customers in recent years is not a sufficient predictor of future requirements that might arise. If a small load is close to the transmission system and is a significant distance to the closest distribution line, it may be that the best engineering solution is to connect to the transmission system. The AESO has provided no evidence why such circumstances, which clearly have occurred in the past, will no longer occur in the future. Other problems about transferring between rate classes (page 8, first paragraph) are solved when both rate classes are properly designed and consistent between rates, costs and investment levels. The AESO should not need to block movement between the rate classes if the conditions, obligations and charges are met by the customer.

TransCanada recommends that the AESO examine a multivariable analysis of radial line costs. The AESO Discussion Paper stated (p. 5) that these costs correlated well to line length but poorly to DTS capacity. This is contrary to the well accepted engineering practice of estimating the cost of transmission lines by estimating the cost of the line per km for a given voltage level (where the terrain, brushing and other variables are not significant). If the AESO corrects for inflation in the Alberta context, obtains accurate estimates of the costs (rather than using preliminary estimates) and obtains accurate dates for project completion, there should be a

multi-variable correlation for voltage level and line length. If not, the AESO needs to perform further analysis to see if some outliers involving unusual circumstances should be removed from the analysis or adjusted to reflect the unusual circumstances.

TransCanada is also concerned about the following:

1. The exclusion of normal transmission charges for Isolated Generating Units since they have no transmission costs (page 6). This treatment is likely inappropriate since the generation costs of Isolated Generating Units are being pooled as if they were transmission costs. All other transmission customers are therefore subsidizing Isolated Generation and it is unfair to provide an additional price reduction in the GTS rate given the major cross-subsidy already occurring.
2. The AESO states (page 6) that it has been unable to determine project costs for small loads interconnected to the transmission system. If this is the case, how will these assets be retired by the TFO when they are no longer used and useful? The AESO may need to inquire further with the TFOs to obtain this information.
3. The proposal (page 8) to exclude rate GTS from applying to substations with multiple points of service due to the use of a substation fraction is unnecessary if rate GTS is properly designed. If a small customer can be served from a substation that is designed to serve another but much larger customer and where service from the Distribution system would be more expensive, that customer should be permitted to be served from the substation. By insisting that the small customer pay charges that are only suitable for a large customer, even though those charges are reduced using a substation fraction, the more cost effective engineering solution may be blocked. The application of a substation fraction does not provide an accurate cost signal for smaller customers; it is only designed to allocate the higher costs of serving large customers among the larger customers who cause the costs. In many cases, smaller customers do not cause as many costs per MW of capacity as larger customers.

Backup Transmission Service Rate

7. A rate with a \$/MWh System Charge equivalent to the DTS System Charge at 10% load factor and no POD Charge is an appropriate backup service for short-duration, infrequent use of the transmission system.
- Support (qualified)
 Oppose
 Indifferent

Reasons for Stakeholder Position: TransCanada offers qualified support for a Backup Transmission Service Rate. TransCanada requests clarification that:

- (a) the AESO intends that the 10% load factor limit is applied on an annual basis (or a 12 month rolling average)
- (b) the standby service is provided on a firm basis
- (c) the length of time that the standby service can be contracted for
- (d) the process for allocation of limited transmission capacity
- (e) whether rate BTS might be provided on a non-firm basis and the conditions that would apply

Export and Import Rates

8. Rate XTS in the proposed rate schedules will be provided for non-recallable export transmission service.
- Support (qualified)
 Oppose

Indifferent

Reasons for Stakeholder Position: TransCanada offers qualified support for Rate XTS. Before this rate is implemented, the AESO should address the following concerns:

- (a) Could the rate be offered as firm service equivalent to Rate DTS (curtailment priority 29) with an option to accept a pre-curtailment before step 29 and receive the UFLS Credit (if desired)?
- (b) For circumstances where no new transmission is constructed for these customers, provide a reduction (such as 50%) in the bulk system and local system cost allocations.
- (c) Clarify that Rate XTS is only charged in the hours when ATC is available and not cut before or during the hour. The current wording in the tariff implies that the rate will be charged even if the service is withdrawn.
- (d) Clarify that Rate XTS may include different amounts every hour given the amount of ATC available and the amount that the Customer chooses to book on the service.
- (e) What general process will the AESO follow if there is an oversubscription of available capacity? Confirm that this process will be addressed in the AESO's OPPs as implied on page 12 and that the process will be completed at or before the tariff becomes available.

9. Rates XOS 1 Hour and XOS 1 Month in the proposed rate schedules will be provided for export opportunity service.

Support (qualified)
 Oppose
 Indifferent

Reasons for Stakeholder Position: TransCanada is generally supportive of Rates XOS 1 Hour and Rate XOS 1 Month. However TransCanada would like clarification on the reasons for the substantial price difference between these two tariffs. They are both opportunity service tariffs that can be cut before or during the hour of a transaction. No transmission is built for them and they are required to pay all incremental losses. The XOS 1 Month rate appears to be excessive under these circumstances.

Merchant Export and Import Rates

10. Rates XTS, XOS 1 Hour, and XOS 1 Month be reduced by the share of costs attributable to the existing inter-ties when applied to service over merchant inter-ties.

Support
 Oppose
 Indifferent

Reasons for Stakeholder Position: TransCanada is disappointed that the AESO has not developed Merchant Transmission Rates that are "appropriate for the class of service provided to persons who use the facilities referred to in this section for import and export of electricity to and from Alberta" per Section 15(6) of the Transmission Regulation. Merchant Transmission lines are specifically identified as persons "referred to in this section" per Section 15(1) (a) of the Transmission Regulation. TransCanada will undertake to work with the AESO on this matter to explore a Merchant Transmission tariff that addresses the needs of Merchant Transmission lines. Overall, TransCanada is concerned that discounting the existing export and import tariffs by the costs of existing inter-ties of \$0.62/MWh is substantially too small in circumstances where a Merchant Transmission line uses only a very limited portion of the AES to interconnect with generation sources or loads.

Primary Service Credit

11. The Primary Service Credit level should be increased to \$599.00/MW + (11,373.00/month × Substation Fraction) based on project costs analysis in the customer contribution policy study:
- Support (qualified)
 Oppose
 Indifferent

Reasons for Stakeholder Position: TransCanada offers qualified support for this change to the Primary Service Credit. Again, as noted earlier, if the analysis in the customer contribution study needs further revisions, those revisions will impact on the level of the Primary Service Credit. Also, in the case where the customer owns the substation, the Primary Service Credit should not be reduced by the Substation Fraction, or, alternatively, the costs that are not reduced by the substation fraction (i.e. the remaining costs to be born by the Customer) should be reimbursed to the entity that owns the Substation, not a TFO or the AESO who has no ownership interest in the substation.

Additional Comments

Due to the short period of time for comments and since consultations are occurring in the summer vacation period, the comments provided are not necessarily complete. TransCanada reserves the right to provide further comments at a later date.

Please return this form with your comments by July 11, 2006, to:

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