

**Stakeholder Comments**  
**AESO 2006 Transmission Cost Causation Update: Draft Report**  
July 31, 2006

Written comments were received from:

ADC

ATCO Electric

CNRL

EnCana

EPCOR

IPCAA

TransCanada

**AESO 2006 Transmission Cost Causation Update  
Draft Report — 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](mailto:Colette@valeopower.com) / [carrie@valeopower.com](mailto:carrie@valeopower.com)

**2. Bulk System Demand Related Costs**

The time of maximum stress on the Bulk system cannot be reliably predicted by considering the peak system load in Alberta.

- Support  
 Oppose  
 Indifferent

Reasons for Stakeholder Position: The ADC does agree that the issue of when a particular line achieves or nears its condition of maximum stress does not have a simple relationship to the coincident demand of the province. Nevertheless, the ADC cannot agree that the coincident loads of large groups of customers plays no role in the need to upgrade or reinforce the transmission system.\* There is simply too much precedent across North America for the use of coincident demands to totally discard that parameter based on the data contained in the latest study. The ADC suggests that additional analyses may be justified to shed more light on this issue, including but not limited to 1) Examining data for more than just one year; 2) examining the relationship between *regional* coincident loads and the times when maximum stress is achieved or nearly achieved on lines within that region; 3) aggregating groups of transmission paths in the analysis instead of individual lines.

\* P. 12 of TCCS Update states that the system is planned as a whole and considers interaction between components.

The maximum demand at each POD is an appropriate indicator of contribution to stress on the Bulk System.

- Support  
 Oppose  
 Indifferent

Reasons for Stakeholder Position: The ADC has seen no statistical evidence or evidence from planning criteria that would indicate the validity of this statement. While CP demand may not be a perfect indicator of bulk transmission needs, the situation appears more complex than that indicated by using non-coincident demand as a simple expedient.

**3. Interprovincial Ties**

The interprovincial ties comprise of 17% of the NBV of the Bulk System.

- Support  
 Oppose  
 Indifferent

Reasons for Stakeholder Position: Assuming that \$1,456 million cited in the PST study includes the NBV of the interprovincial ties, this statement appears to be correct.

<p>The cost of the interprovincial ties should continue to be part of the Bulk System.</p>	<input checked="" type="checkbox"/> Support <input type="checkbox"/> Oppose <input type="checkbox"/> Indifferent
<p>Reasons for Stakeholder Position: As the cost of interprovincial ties form part of the revenue requirement which must be recovered through the AESO tariff, and since these ties are clearly not local or POD related, the ADC agrees that Bulk System is the only remaining category that could be considered logical.</p>	

<p><b>4. Local System</b></p>	
<p>Based on the data currently available, the expected small impact of the refinement, and the resulting misalignment between functionalization and cost treatment in the contribution policy, it seems appropriate to continue the functionalization proposed in the original <i>Transmission Cost Causation Study</i>.</p>	<input checked="" type="checkbox"/> Support <input type="checkbox"/> Oppose <input type="checkbox"/> Indifferent
<p>Reasons for Stakeholder Position: The ADC agrees with the logic inherent in the above statement.</p>	

<p><b>5. Point of Delivery Costs</b></p>	
<p>The AESO will rely on the contribution policy study data for additional analysis of POD costs.</p>	<input checked="" type="checkbox"/> Support <input type="checkbox"/> Oppose <input type="checkbox"/> Indifferent
<p>Reasons for Stakeholder Position: The ADC would support the use of contribution policy study data as long as the data is reflective of finalized POD costs.</p>	

<p><b>6. Contributions In Aid of Construction (CIAC)</b></p>	
<p>The cost functionalization has been appropriately adjusted to reflect the refinement to CIAC treatment.</p>	<input type="checkbox"/> Support <input type="checkbox"/> Oppose <input type="checkbox"/> Indifferent
<p>Reasons for Stakeholder Position:</p>	

<p><b>7. Dual Use Substations</b></p>	
<p>The functionalization of point of exchange costs between dual-use load and supply customers cannot be determined through analysis of the cost data. Costs will always need to be shared between the two functions. In the AESO's case, the EUB has approved cost sharing based on the substation fraction approach.</p>	<input type="checkbox"/> Support <input type="checkbox"/> Oppose <input type="checkbox"/> Indifferent
<p>Reasons for Stakeholder Position:</p>	

**8. Operations, Maintenance, and Administration**

At this time, there is insufficient data to properly allocate OM&A costs by function, vintage or equipment type.  Support  
 Oppose  
 Indifferent

Reasons for Stakeholder Position:

The impact of functionalizing OM&A is likely to be small because:  
• OM&A accounts for about ¼ of the revenue requirement,  Support  
• Difference in OM&A accounting for equipment age is likely to be small because all equipment is similarly aged,  Oppose  
• Difference in OM&A accounting for difference between substations and lines is likely to be small since the largest function (Bulk System) is relatively equally split by line and substation equipment.  Indifferent

Reasons for Stakeholder Position:

**9. Recommended Additional Activities**

*Local System and Point of Delivery* — After development of aligned definitions, the TCCS should be reviewed with functions that align to the Customer Contribution Policy.  Support  
 Oppose  
 Indifferent

Reasons for Stakeholder Position: It is important to have a customer contribution policy that is aligned with costs to serve.

*Operations, Maintenance, and Administration* — Since OM&A accounts for a small portion of the total revenue requirement, better functionalization of OM&A may not change the results of the TCCS study significantly.  Support  
 Oppose  
 Indifferent

Reasons for Stakeholder Position:

**Additional Comments**

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

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Manager, Regulatory  
E-mail: [john.martin@aeso.ca](mailto:john.martin@aeso.ca)  
Phone: (403) 539-2465  
Fax: (403) 539-2524

**AESO 2006 Transmission Cost Causation Update  
Draft Report — Stakeholder Comment Form**

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

**2. Bulk System Demand Related Costs**

The time of maximum stress on the Bulk system cannot be reliably predicted by considering the peak system load in Alberta.  Support  
 Oppose  
 Indifferent

Reasons for Stakeholder Position:

The maximum demand at each POD is an appropriate indicator of contribution to stress on the Bulk System.  Support  
 Oppose  
 Indifferent

Reasons for Stakeholder Position:

ATCO Electric believes that the Bulk system is planned to meet system load under numerous conditions. These conditions includes loads in summer and winter at peak and off peak hours, various generation patterns and contingencies, extreme hydro conditions, unit turn around and low system load conditions. The POD peak demand is not a good representative of the system loading conditions that are used for the Bulk system planning purposes. In ATCO Electric's view, annual energy is a more appropriate representative of these loading conditions as these conditions happen over several hours and are distributed throughout the year. As such, energy should be used for the recovery of costs associated with the Bulk system.

**3. Interprovincial Ties**

The interprovincial ties comprise of 17% of the NBV of the Bulk System.  Support  
 Oppose  
 Indifferent

Reasons for Stakeholder Position:

The cost of the interprovincial ties should continue to be part of the Bulk System.  Support  
 Oppose  
 Indifferent

Reasons for Stakeholder Position:

**4. Local System**

Based on the data currently available, the expected small impact of the refinement, and the resulting misalignment between functionalization and cost treatment in the contribution policy, it seems appropriate to continue the functionalization proposed in the original *Transmission Cost Causation Study*.  Support  
 Oppose  
 Indifferent

Reasons for Stakeholder Position:

**5. Point of Delivery Costs**

The AESO will rely on the contribution policy study data for additional analysis of POD costs.

- Support
- Oppose
- Indifferent

Reasons for Stakeholder Position:

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 would not be appropriate, especially if used for the determination of fixed POD charges for small PODs. However, this concern would be mitigated if the GTS rate for small PODs is accepted.

**6. Contributions In Aid of Construction (CIAC)**

The cost functionalization has been appropriately adjusted to reflect the refinement to CIAC treatment.

- Support
- Oppose
- Indifferent

Reasons for Stakeholder Position:

**7. Dual Use Substations**

The functionalization of point of exchange costs between dual-use load and supply customers cannot be determined through analysis of the cost data. Costs will always need to be shared between the two functions. In the AESO's case, the EUB has approved cost sharing based on the substation fraction approach.

- Support
- Oppose
- Indifferent

Reasons for Stakeholder Position:

**8. Operations, Maintenance, and Administration**

At this time, there is insufficient data to properly allocate OM&A costs by function, vintage or equipment type.

- Support
- Oppose
- Indifferent

Reasons for Stakeholder Position:

<p>The impact of functionalizing OM&amp;A is likely to be small because:</p> <ul style="list-style-type: none"> <li>• OM&amp;A accounts for about ¼ of the revenue requirement,</li> <li>• Difference in OM&amp;A accounting for equipment age is likely to be small because all equipment is similarly aged,</li> <li>• Difference in OM&amp;A accounting for difference between substations and lines is likely to be small since the largest function (Bulk System) is relatively equally split by line and substation equipment.</li> </ul>	<input type="checkbox"/> Support <input type="checkbox"/> Oppose <input type="checkbox"/> Indifferent
<p>Reasons for Stakeholder Position:</p>	

<p><b>9. Recommended Additional Activities</b></p>	
<p><i>Local System and Point of Delivery</i> — After development of aligned definitions, the TCCS should be reviewed with functions that align to the Customer Contribution Policy.</p>	<input checked="" type="checkbox"/> Support <input type="checkbox"/> Oppose <input type="checkbox"/> Indifferent
<p>Reasons for Stakeholder Position:</p>	
<p><i>Operations, Maintenance, and Administration</i> — Since OM&amp;A accounts for a small portion of the total revenue requirement, better functionalization of OM&amp;A may not change the results of the TCCS study significantly.</p>	<input type="checkbox"/> Support <input type="checkbox"/> Oppose <input type="checkbox"/> Indifferent
<p>Reasons for Stakeholder Position:</p>	

<p><b>Additional Comments</b></p>

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

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**AESO 2006 Transmission Cost Causation Update  
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Comments From: Canadian Natural Resources Limited  
Date: July 10<sup>th</sup>, 2006  
Contact: Dean Chesterman  
Phone: (403) 669 - 6051  
E-mail: chesterman.consulting@shaw.ca

**2. Bulk System Demand Related Costs**

The time of maximum stress on the Bulk system cannot be reliably predicted by considering the peak system load in Alberta.

Support  
 Oppose  
 Indifferent

Reasons for Stakeholder Position: Agreed, the Peak System Load as the bulk system maximum stress has always been an easily defended and easily measured data point. Historically, with a central generation / distributed load scenario, there was little justification for considering any other proxy for maximum stress. Now that Alberta has developed with major generation centres in Southern Alberta, Fort McMurray and distributed generation in Grande Prairie, Peace River, Medicine Hat and other areas, the old proxy is no longer valid.

The maximum demand at each POD is an appropriate indicator of contribution to stress on the Bulk System.

Support  
 Oppose  
 Indifferent

Reasons for Stakeholder Position: Somewhat agree. The Maximum Stress at the POD can be demonstrated as the maximum stress on the bulk system at that point, but this ignores the network affects. The network affects are clearly seen in the large number of lines with negative correlations. The transmission system was developed on the single contingency with worst placed generator out of service scenario. With all lines in service there are very likely to be reduced and even reversed flows on a specific transmission line as compared to the case that was used to justify the installation of that transmission line.

One Factor in Maximum Stress is the Maximum Demand at each POD.  
Other factors include; Generation Dispatch, Contingencies, Thermal Limits, Dynamic Limits, Voltage Control, network effects, available Static and Dynamic reactive sources and etc.

For the POD charges though, there is a clear pattern of Maximum Demand being Maximum Stress on the local system. For the rest of the transmission system there is no clear proxy.

**3. Interprovincial Ties**

The interprovincial ties comprise of 17% of the NBV of the Bulk System.

Support  
 Oppose  
 Indifferent

Reasons for Stakeholder Position: CNRL is a majority DTS customer. The interprovincial ties have no influence on CNRL's normal operations; however, the impact of the imports over the interprovincial ties and the system adequacy graphs has been noted.

The cost of the interprovincial ties should continue to be part of the Bulk System.  Support  
 Oppose  
 Indifferent

Reasons for Stakeholder Position: It appears clear that imports have a huge impact on the system adequacy charts and should thus be included as one of the resources to support the transmission system. The costs of the interprovincial ties should continue to be part of the Bulk Transmission system.

**4. Local System**

Based on the data currently available, the expected small impact of the refinement, and the resulting misalignment between functionalization and cost treatment in the contribution policy, it seems appropriate to continue the functionalization proposed in the original *Transmission Cost Causation Study*.  Support  
 Oppose  
 Indifferent

Reasons for Stakeholder Position: There is a misalignment, but without more data and much more time to analysis it there is little opportunity to reduce the misalignment at this time.

**5. Point of Delivery Costs**

The AESO will rely on the contribution policy study data for additional analysis of POD costs.  Support  
 Oppose  
 Indifferent

Reasons for Stakeholder Position: Agreed, the more data analysed and the better quality data analysed the better the decisions around the contribution policy

**6. Contributions In Aid of Construction (CIAC)**

The cost functionalization has been appropriately adjusted to reflect the refinement to CIAC treatment.  Support  
 Oppose  
 Indifferent

Reasons for Stakeholder Position:

**7. Dual Use Substations**

The functionalization of point of exchange costs between dual-use load and supply customers cannot be determined through analysis of the cost data. Costs will always need to be shared between the two functions. In the AESO's case, the EUB has approved cost sharing based on the substation fraction approach.  Support  
 Oppose  
 Indifferent

Reasons for Stakeholder Position: CNRL disagrees with this. Granted it is difficult to separate the use of the system by DTS vs STS, but as has been argued and accepted by the Board in previous hearings around the COS credit, the substation fraction is not required. With the DTS customers paying for the transmission system, and with the Load First approach, the DTS customers are bearing the costs and should be getting the full credit for building their own substations.

## 8. Operations, Maintenance, and Administration

At this time, there is insufficient data to properly allocate OM&A costs by function, vintage or equipment type.

- Support  
 Oppose  
 Indifferent

Reasons for Stakeholder Position: Agreed, the transmission cost accounts were never set up to separate functions or to vintage installations or equipment type. For most of the accounts, the whole substation or even multiple substations and substation enhancements were combined into one project and then charged to the general asset accounts.

The impact of functionalizing OM&A is likely to be small because:

- OM&A accounts for about  $\frac{1}{4}$  of the revenue requirement,
- Difference in OM&A accounting for equipment age is likely to be small because all equipment is similarly aged,
- Difference in OM&A accounting for difference between substations and lines is likely to be small since the largest function (Bulk System) is relatively equally split by line and substation equipment.

- Support  
 Oppose  
 Indifferent

Reasons for Stakeholder Position: Agreed, this would be interesting to identify, but the data sources and the resources required for the analysis are not likely available in time. There is still merit in considering a future study as there are different people doing different activities for the O&M of the substations vs the transmission lines.

## 9. Recommended Additional Activities

*Local System and Point of Delivery* — After development of aligned definitions, the TCCS should be reviewed with functions that align to the Customer Contribution Policy.

- Support  
 Oppose  
 Indifferent

Reasons for Stakeholder Position: Agreed, there should be a clear connection between cost causation, tariffs and the contribution policy. Any misalignment should be removed, explained and justified, or identified and left alone if there is no benefit to removing the misalignment. .

*Operations, Maintenance, and Administration* — Since OM&A accounts for a small portion of the total revenue requirement, better functionalization of OM&A may not change the results of the TCCS study significantly.

- Support  
 Oppose  
 Indifferent

Reasons for Stakeholder Position: Disagree, O&M charges for transmission lines and transmission substations are different people doing different activities. There are opportunities for cross subsidization, where line related O&M is charged to a substation. Until the study is done the AESO statement can not be made. One example is the Telecommunications and Teleprotection network. There are possible arguments that all O&M charges are all substation related, all generation related or all line related or some mix. Considering the high cost of maintenance on the typically remote microwave sites, a reallocation of costs may have a significant impact on functionalization of O&M costs.

**Additional Comments**

The AESO has obviously taken the comments from stakeholders, accepted a number of the stakeholder recommendations and has incorporated them into the next version of the studies. This effort is appreciated.

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

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**AESO 2006 Transmission Cost Causation Update  
Draft Report — Stakeholder Comment Form**

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:

**2. Bulk System Demand Related Costs**

The time of maximum stress on the Bulk system cannot be reliably predicted by considering the peak system load in Alberta.

Support  
 Oppose  
 Indifferent

Reasons for Stakeholder Position:

The TCC-Update makes too many spurious associations. First, it presumes “maximum stress” is a reasonable proxy for transmission planning decisions. There is insufficient investigation of actual transmission planning to conclude that “maximum stress” is appropriate terminology or concept. Second, it presumes that “maximum stress” can be simplified to a single circuit line loading without any loss of meaning or ability to explain transmission planning. The TCC-Update readily admits that transmission planning is complex and driven by multiple independent factors yet there is no investigation as to the portion of transmission developments that are caused by reasons other than line loading. Instead, the Update presumes a 100% correlation between transmission expansions and line loading when it is not the case.

The resulting AIL peak & line loading correlation analysis does not measure the relevant associations between load and transmission system expansions and cost causation. Nor can it distinguish between the predictive ability of peak system load versus any other measure of load since no other relationship between load and transmission expansions were investigated. In other words, the TCC-Update is unable to say what other measures of load are a more reliable predictor of “maximum stress” than peak system load. This is an important conclusion because it means the TCC-Update is unable to demonstrate that maximum POD demand (i.e. “billing capacity”) has any better or worse ability to predict a customer’s contribution to transmission stress.

The maximum demand at each POD is an appropriate indicator of contribution to stress on the Bulk System.

Support  
 Oppose  
 Indifferent

Reasons for Stakeholder Position:

The TCC-Update has not provided any statistical or qualitative support which shows that maximum POD demand is the best correlation with “maximum stress” or transmission cost causation.

The TCC-Update appears to support “maximum POD demand” (billing capacity) for its ability to be “known”, “easy to understand” and “less volatile” than load coincident to AIL peak system load. This can also be said of many other definitions of demand, including on-peak average, seasonal demand or the average of all-hour demand (i.e. energy), yet the TCC-Update does not (a) give mention to any other definition or characterisation of demand and (b) investigate the relative merits and correlation of these other definitions. Why?

In EnCana's view, the TCC-Update is incomplete because it has not investigated the merits of any other characterisation of load demand.

### 3. Interprovincial Ties

The interprovincial ties comprise of 17% of the NBV of the Bulk System.

- Support
- Oppose
- Indifferent

Reasons for Stakeholder Position:

The cost of the interprovincial ties should continue to be part of the Bulk System.

- Support
- Oppose
- Indifferent

Reasons for Stakeholder Position:

### 4. Local System

Based on the data currently available, the expected small impact of the refinement, and the resulting misalignment between functionalization and cost treatment in the contribution policy, it seems appropriate to continue the functionalization proposed in the original *Transmission Cost Causation Study*.

- Support
- Oppose
- Indifferent

Reasons for Stakeholder Position:

Every effort should be made to address any misalignment or misallocation of costs in the rate design as compared to the contribution policy.

### 5. Point of Delivery Costs

The AESO will rely on the contribution policy study data for additional analysis of POD costs.

- Support
- Oppose
- Indifferent

Reasons for Stakeholder Position:

### 6. Contributions In Aid of Construction (CIAC)

The cost functionalization has been appropriately adjusted to reflect the refinement to CIAC treatment.

- Support
- Oppose
- Indifferent

Reasons for Stakeholder Position:

**7. Dual Use Substations**

The functionalization of point of exchange costs between dual-use load and supply customers cannot be determined through analysis of the cost data. Costs will always need to be shared between the two functions. In the AESO's case, the EUB has approved cost sharing based on the substation fraction approach.

- Support
- Oppose
- Indifferent

Reasons for Stakeholder Position:

Every effort should be made to address the allocation of costs.

**8. Operations, Maintenance, and Administration**

At this time, there is insufficient data to properly allocate OM&A costs by function, vintage or equipment type.

- Support
- X  Oppose
- Indifferent

Reasons for Stakeholder Position:

The impact of functionalizing OM&A is likely to be small because:

- OM&A accounts for about ¼ of the revenue requirement,
- Difference in OM&A accounting for equipment age is likely to be small because all equipment is similarly aged,
- Difference in OM&A accounting for difference between substations and lines is likely to be small since the largest function (Bulk System) is relatively equally split by line and substation equipment.

- Support
- X  Oppose
- Indifferent

Reasons for Stakeholder Position:

It is unclear to EnCana why the TCC-Update is considering the *functionalization* of O&M when the Board directed the examination of the *classification* of O&M; that is, the extent to which O&M costs are energy-related. Because the TCC-Update does not investigate the classification of O&M costs, as much as 25% to 33% of the wires costs could be mis-classified.

EnCana requests that AESO and TCC-Update to address the classification of the O&M costs.

**9. Recommended Additional Activities**

*Local System and Point of Delivery* — After development of aligned definitions, the TCCS should be reviewed with functions that align to the Customer Contribution Policy.

- Support
- Oppose
- Indifferent

Reasons for Stakeholder Position:

<p><i>Operations, Maintenance, and Administration</i> — Since OM&amp;A accounts for a small portion of the total revenue requirement, better functionalization of OM&amp;A may not change the results of the TCCS study significantly.</p>	<input type="checkbox"/> Support <input type="checkbox"/> Oppose <input type="checkbox"/> Indifferent
<p>Reasons for Stakeholder Position:</p>	

<p><b>Additional Comments</b></p> <p>In EnCana's view the AESO has not established a long-term vision as to the direction of the rate design and cost causation studies and as a result the TCCS approaches the Cost Causation on a piecemeal basis. The lack of a coherent long-term vision is counter-productive and will result in continuing revisions to the cost causation studies and ultimately the rate design. EnCana reiterates its request to establish with stakeholders a long-term vision of the rate-design.</p>
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Please return this form with your comments by July 11, 2006, to:

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**AESO 2006 Transmission Cost Causation Update  
Draft Report — Stakeholder Comment Form**

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

**2. Bulk System Demand Related Costs**

The time of maximum stress on the Bulk system cannot be reliably predicted by considering the peak system load in Alberta.  Support  
 Oppose  
 Indifferent

Reasons for Stakeholder Position: As described in the 2006 Transmission Cost Causation Update, EPCOR is in agreement that “the correlation between coincident peak load and stress on the Bulk System is very weak.”

The maximum demand at each POD is an appropriate indicator of contribution to stress on the Bulk System.  Support  
 Oppose  
 Indifferent

Reasons for Stakeholder Position: The maximum demand at each POD exhibits less variability than the AIL CP. The maximum demand at each POD is known and is a better measure of transmission cost causation. Coincident peak is relevant only at the generation level.

**3. Interprovincial Ties**

The interprovincial ties comprise of 17% of the NBV of the Bulk System.  Support  
 Oppose  
 Indifferent

Reasons for Stakeholder Position: EPCOR does not see the value in separating out the interprovincial ties from the Bulk System.

The cost of the interprovincial ties should continue to be part of the Bulk System.  Support  
 Oppose  
 Indifferent

Reasons for Stakeholder Position: Based on the definitions of Bulk and Local Systems as presented in the draft report, interprovincial ties are reasonably characterized as Bulk System assets.

**4. Local System**

Based on the data currently available, the expected small impact of the refinement, and the resulting misalignment between functionalization and cost treatment in the contribution policy, it seems appropriate to continue the functionalization proposed in the original *Transmission Cost Causation Study*.  Support  
 Oppose  
 Indifferent

Reasons for Stakeholder Position: EPCOR agrees, as no new evidence has been provided to

date.

### 5. Point of Delivery Costs

The AESO will rely on the contribution policy study data for additional analysis of POD costs.

- Support  
 Oppose  
 Indifferent

Reasons for Stakeholder Position: EPCOR is supportive of this approach, provided that any additional analysis only be carried out if the benefits can be reasonably expected to outweigh the costs of such analysis.

### 6. Contributions In Aid of Construction (CIAC)

The cost functionalization has been appropriately adjusted to reflect the refinement to CIAC treatment.

- Support  
 Oppose  
 Indifferent

Reasons for Stakeholder Position:

### 7. Dual Use Substations

The functionalization of point of exchange costs between dual-use load and supply customers cannot be determined through analysis of the cost data. Costs will always need to be shared between the two functions. In the AESO's case, the EUB has approved cost sharing based on the substation fraction approach.

- Support  
 Oppose  
 Indifferent

Reasons for Stakeholder Position: Given the shift in cost functionalization over time, analysis of data can be difficult and not cost-effective. It is therefore reasonable to use the substation fraction approach as it is the AESO's most recently approved cost sharing method.

### 8. Operations, Maintenance, and Administration

At this time, there is insufficient data to properly allocate OM&A costs by function, vintage or equipment type.

- Support  
 Oppose  
 Indifferent

Reasons for Stakeholder Position: EPCOR agrees that there is insufficient data to properly allocated OM&A costs and feel there is questionable value to this approach

The impact of functionalizing OM&A is likely to be small because:

- OM&A accounts for about ¼ of the revenue requirement,
- Difference in OM&A accounting for equipment age is likely to be small because all equipment is similarly aged,
- Difference in OM&A accounting for difference between substations and lines is likely to be small since the largest function (Bulk System) is relatively equally split by line and substation equipment.

- Support  
 Oppose  
 Indifferent

Reasons for Stakeholder Position: Although the high level assumptions do not seem unreasonable, further analysis might be best to determine any impacts. EPCOR suggests that no further activities take place until the Uniform System of Accounts initiative being undertaken

by the EUB is finalized. Any work done before this time would result in costs outweighing any foreseen benefits.

**9. Recommended Additional Activities**

*Local System and Point of Delivery* — After development of aligned definitions, the TCCS should be reviewed with functions that align to the Customer Contribution Policy.  Support  
 Oppose  
 Indifferent

Reasons for Stakeholder Position:

*Operations, Maintenance, and Administration* — Since OM&A accounts for a small portion of the total revenue requirement, better functionalization of OM&A may not change the results of the TCCS study significantly.  Support  
 Oppose  
 Indifferent

Reasons for Stakeholder Position: Again, EPCOR suggests that no further activities take place until the Uniform System of Accounts initiative being undertaken by the EUB is finalized. Any work done before this time would result in costs outweighing any foreseen benefits.

**Additional Comments**

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

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**AESO 2006 Transmission Cost Causation Update  
Draft Report — Stakeholder Comment Form**

Comments From: IPCAA  
 Date: July 10, 2006  
 Contact: Ron Mikkelsen / Dan Macnamara  
 Phone: (403) 263-3326 / 266-3180  
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<b>2. Bulk System Demand Related Costs</b>	
The time of maximum stress on the Bulk system cannot be reliably predicted by considering the peak system load in Alberta.	<input type="checkbox"/> Support <input type="checkbox"/> Oppose <input checked="" type="checkbox"/> Indifferent
Reasons for Stakeholder Position: From the text of the TCCS it is not apparent if any analysis was undertaken distinguishing between on-peak and off peak hours of the day. Are the correlations etc. examined consistent for on-peak and off-peak periods?	
The maximum demand at each POD is an appropriate indicator of contribution to stress on the Bulk System.	<input type="checkbox"/> Support <input type="checkbox"/> Oppose <input checked="" type="checkbox"/> Indifferent
Reasons for Stakeholder Position:	
<b>3. Interprovincial Ties</b>	
The interprovincial ties comprise of 17% of the NBV of the Bulk System.	<input type="checkbox"/> Support <input type="checkbox"/> Oppose <input checked="" type="checkbox"/> Indifferent
Reasons for Stakeholder Position:	
The cost of the interprovincial ties should continue to be part of the Bulk System.	<input type="checkbox"/> Support <input type="checkbox"/> Oppose <input checked="" type="checkbox"/> Indifferent
Reasons for Stakeholder Position:	
<b>4. Local System</b>	
Based on the data currently available, the expected small impact of the refinement, and the resulting misalignment between functionalization and cost treatment in the contribution policy, it seems appropriate to continue the functionalization proposed in the original <i>Transmission Cost Causation Study</i> .	<input checked="" type="checkbox"/> Support <input type="checkbox"/> Oppose <input type="checkbox"/> Indifferent
Reasons for Stakeholder Position:	

**5. Point of Delivery Costs**

The AESO will rely on the contribution policy study data for additional analysis of POD costs.

- Support  
 Oppose  
 Indifferent

Reasons for Stakeholder Position:

**6. Contributions In Aid of Construction (CIAC)**

The cost functionalization has been appropriately adjusted to reflect the refinement to CIAC treatment.

- Support  
 Oppose  
 Indifferent

Reasons for Stakeholder Position:

**7. Dual Use Substations**

The functionalization of point of exchange costs between dual-use load and supply customers cannot be determined through analysis of the cost data. Costs will always need to be shared between the two functions. In the AESO's case, the EUB has approved cost sharing based on the substation fraction approach.

- Support  
 Oppose  
 Indifferent

Reasons for Stakeholder Position:

**8. Operations, Maintenance, and Administration**

At this time, there is insufficient data to properly allocate OM&A costs by function, vintage or equipment type.

- Support  
 Oppose  
 Indifferent

Reasons for Stakeholder Position:

The impact of functionalizing OM&A is likely to be small because:

- OM&A accounts for about 1/4 of the revenue requirement,
- Difference in OM&A accounting for equipment age is likely to be small because all equipment is similarly aged,
- Difference in OM&A accounting for difference between substations and lines is likely to be small since the largest function (Bulk System) is relatively equally split by line and substation equipment.

- Support  
 Oppose  
 Indifferent

Reasons for Stakeholder Position:

**9. Recommended Additional Activities**

*Local System and Point of Delivery* — After development of aligned definitions, the TCCS should be reviewed with functions that align to the Customer Contribution Policy.

- Support  
 Oppose  
 Indifferent

Reasons for Stakeholder Position:

*Operations, Maintenance, and Administration* — Since OM&A accounts for a small portion of the total revenue requirement, better functionalization of OM&A may not change the results of the TCCS study significantly.

- Support  
 Oppose  
 Indifferent

Reasons for Stakeholder Position:

**Additional Comments**

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

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July 28, 2006

John Martin  
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Dear John:

TransCanada Energy (“TransCanada”) has reviewed the “2006 Transmission Cost Causation Update” July 4, 2006 – Draft prepared by PS Technologies (the “Cost Causation Update”) and the AESO Rates Analysis that builds upon the Cost Causation Update and offers the following comments.

TransCanada is concerned about the adequacy of the Cost Causation Update that is being used to support a significant change in the rate design of the Demand Transmission Service (DTS) Rate. The AESO is proposing to move from a coincident peak (“CP”) method to a non-coincident peak (“NCP”) method for the allocation of bulk system costs. The AESO indicates that the bulk system is 41% (or \$144.6 million) of the total wires related costs of \$352.6 million. Further, about 66% of the bulk system costs (or \$95.4 million) would be allocated on a coincident peak method under the current method.<sup>1</sup> If the AESO proposal is approved, the \$95.4 million would then be allocated on an NCP basis.

In support of its proposed tariffs, the AESO has not adhered to industry practice in that it has not conducted a traditional cost of service study, an incremental cost study or a short run marginal cost study. The AESO has instead conducted what is effectively a Transmission Line Usage study based on recent transmission flow activity. In this letter, TransCanada will describe its concerns with the Cost Causation Update and recommend that the AESO conduct a full cost of service study in support of any recommended changes to allocation of bulk system costs.

### **TransCanada Concerns**

TransCanada’s concerns with the Cost Causation Update and the AESO’s subsequent rate design conclusions are (1) insufficient justification to depart from industry practice, (2) moving to the NCP approach results in counter-intuitive impacts to customers and removes incentives for beneficial behaviour (3) the AESO has not followed a standard approach to cost of service studies and (4) the

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<sup>1</sup> Refer to Table 4.3.1 and Table 4.3.3 in AESO 2007 General Tariff Application, Draft Section 4 – 2007 Rate Design, pages 4 and 9, respectively.

underlying assumptions used by the AESO for transmission usage in the Cost Causation Update are problematic.

Details of these concerns are outlined below:

1. The AESO by suggesting that bulk transmission cost causation be allocated on an NCP method is proposing a dramatic departure from industry practice. The AESO has not sufficiently justified why such a unique approach is needed in Alberta. Specifically:
  - a. In the industry, it has been generally accepted that transmission lines are sized based on peak demand. For example, the National Association of Regulatory Utility Commissioners (“NARUC”) concluded: “Since generating units and transmission lines are sized according to the peak demand consumed, the individual contribution to peak demand came to be considered the appropriate factor for the allocation of the costs of those facilities.”<sup>2</sup> It remains unclear to TransCanada whether system peaks and transmission line peaks are materially different from a planning perspective and whether the system peak can provide a reasonable proxy to the transmission line peak for transmission line planning purposes.
  - b. While NCP may be used to allocate subtransmission costs, there appears to be little, if any, precedent for the use of NCP for allocating bulk system costs. NARUC confirms the general practice as follows: “Depending on the factual situation present on a utility’s system, it may be appropriate to employ a combination of methods to properly allocate cost responsibility to customers. Thus, an NCP allocation is sometimes used to allocate subtransmission [i.e. local system] costs, while a peak responsibility method based on coincident demands is used for the higher order transmission facilities.”<sup>3</sup>
  - c. The current DTS rate, which includes a diverse allocation using energy, customer, NCP and CP methods, is more moderate and is likely a fairer allocation than would occur by going to the extreme and unprecedented position of moving all bulk system costs to NCP.
  - d. The AESO does not review advantages and disadvantages of the 12 CP method or some other broader definition of an on-peak allocation method versus their proposed NCP methodology. Variations of these more moderate methods were proposed by a significant portion of the load customers (IPCAA, ADC, TransCanada, EnCana) in the 2006 AESO GTA.
  - e. The AESO has not provided any statistical support that NCP will more accurately assign the costs of bulk transmission line costs to customers than would the 12 CP method or a broader definition of an on-peak allocation method.

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<sup>2</sup> Electric Utility Cost Allocation Manual, NARUC, January, 1992, pages 13 to 14

<sup>3</sup> Electric Utility Cost Allocation Manual, NARUC, January, 1992, page 83

- f. The AESO has not included any analysis as to whether application of the 12 CP method or a method involving more on peak hours would adequately reflect cost causation. The 12 CP method assigns some cost responsibility to customers who peak in summer months. The inability of customers to predict the hour when the coincident peak will occur means that load suppression or load shifting activities have to occur in many hours and in every month, therefore reducing the possibility of the free-rider problem. Using a broader definition of the on-peak period for billing purposes will reduce the likelihood of free-rider problems to an immaterial level.
2. Moving to the unusual situation where cost causation for the entire demand related costs on the bulk transmission system is allocated and billed on an NCP approach would result in counter-intuitive impacts to customers and removes incentives for beneficial behaviour. Specifically:
  - a. The NCP method places the same cost burden on off-peak as on-peak loads. As a result, compared to the 12 CP method, the NCP method will allocate more costs for customers who are off-peak, who can control their peaks or who peak randomly. The method eliminates incentives for load shifting or peak suppression. This is contrary to the general practice of encouraging off-peak use of the system to increase overall usage levels and minimize new capital additions. Examples of these types of loads are gas storage facilities, pipelines, non-critical pumping and heating loads at plants, and electricity intensive process plants that can be easily curtailed for a few hours per day. The NCP method does not recognize the probability of a customer's contribution to system peak (and group peak, where there are rate classes). For example, export loads, being largely off-peak, will carry the same cost responsibility as on-peak loads.
  - b. Customers with relatively low load factors will likely experience an adverse impact from the proposed change to NCP. Pipeline loads, gas storage facilities and some gas compression loads will fall into this category. These are loads that have opportunities for either load shifting, load suppression or both. Oil pipelines, with load peaks directly correlated to the volume and type of oil being pumped are particularly harmed. An oil pipeline load may have peaks fairly randomly distributed across all hours. To the extent that the cost impact of an NCP method are flowed through the Discos to residential and farm customers who have relatively low load factors, they could also experience an adverse impact.
  - c. The proposal also creates difficulty in the design of a standby or backup service. The lack of a standby tariff will have an adverse impact on existing cogeneration facilities and will act to discourage future cogeneration facilities.
3. The AESO has not followed a standard approach to cost of service studies. Specifically:
  - a. The conventional approach to cost causation is to start with a traditional cost of service study, an incremental cost study or a short run marginal cost study in order to understand the relationship between costs and drivers. It is not entirely clear, but it appears that AESO has conducted what is effectively a Transmission usage study

based on recent transmission flow patterns a methodology that has not been proven to provide a reasonable basis for cost causation for bulk transmission systems.

- b. In the absence of compelling evidence that a particular cost driver is relevant, more weight should be placed on historical cost drivers that have been demonstrated to be reliable and have a factual underpinning. To ignore cost drivers from the past will create the potential that the customers with load characteristics that drove the need for the original capital costs will not bear an appropriate share of cost responsibility.
- c. The original reasons why the transmission lines were constructed, from a planning perspective, are not included in the Cost Causation Update, nor were they studied in the original Cost Causation Study. The original reasons for transmission line construction are set out in the planning approval documents that were used to obtain approvals. The embedded costs of the transmission system have arisen from the decisions of transmission planners over several decades. The discussions with planners described in the Cost Causation Update appear focused on recent transmission lines, some of which are in the planning or construction process, but are not in service. For those lines that are not in service, they are not a part of the revenue requirement being allocated. For those lines being examined for considerations such as the future Brooks Plant or future wind developments, these considerations are based on forecasts and are therefore speculative. Without input on the original factors driving the need for the transmission lines, the AESO study cannot be considered a traditional embedded cost of service study.
- d. There is a lack of clear evidence that the current transmission usage activity is indicative of how the transmission system was originally planned. For example, TransCanada observes there has been a significant amount of new generation constructed in the Calgary area that materially alters the transmission flows in the north south corridor. This usage can change over time, particularly as pool prices change and more generation is added to the provincial grid. The changed flow patterns may or may not be permanent. The AESO agrees that changes in generation and load profiles can result in changed stresses on the transmission system.<sup>4</sup> The AESO has provided no quantifiable evidence that the transmission flows currently being experienced on the north south corridor are the same as historical patterns (e.g. pre 2000). Only in the context of the North South 500 kV transmission upgrade has the AESO conducted a quantitative planning analysis of peak loads that drive the need for new transmission. Beyond that, there is no evidence that the current flows are indicative of what will be the key drivers for planning future additions to the bulk transmission system. Another potential flaw in the transmission usage analysis is the differences between how a system is planned (and capital costs are incurred) and how a system is operated. Transmission system operators are under materially different

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<sup>4</sup> The AESO states at page 28 of the 2006 Transmission Cost Causation Update that “The maximum stress on the Bulk System is driven by a number of variables including the location of generation and load, the profiles (daily and seasonally) of generation and load, and the configuration of the electric transmission system in Alberta. As these variables change, the time at which maximum stress occurs on the Bulk System will also change.”

circumstances, as they have access to real time information, whereas planners must make decisions on long term forecasts. Extensive and detailed analysis of how the system is operated is not necessarily a good indicator of what drives transmission costs.

- e. The Cost Causation Update does not include transmission modeling work that arises from planning models. Real time flow patterns do not reflect, except by chance, the stressed conditions that occur when transmission planners are applying reliability criteria to determine the need for new transmission lines.<sup>5</sup> For example, on examination of the data provided by the AESO, TransCanada found the flows on 911 L from Calgary to Peigan never exceeds 90 MW, yet the line has a capacity of 337 MVA in summer and 407 MVA in winter. The line was clearly designed for greater flows than about 30% of the line capacity. Other information provided by the AESO indicates that the average usage of bulk transmission lines as a percentage of the line rating, weighted by line length, is less than 21%. At the same time, the AESO routinely describes the AIES as being stretched to capacity. The difference, as TransCanada understands, is the requirement of the transmission system to maintain reliable supply during worst case contingency conditions.
  - f. TransCanada understands that transmission maintenance is scheduled to avoid on-peak hours during system peak periods. This suggests that system peaks are relevant to transmission reliability.
4. Even if the proposed transmission usage approach were to be accepted, the underlying assumptions used by the AESO for transmission usage in the Cost Causation Update are problematic as follows:
- a. The Cost Causation Update does not correct for the artificial impact that Calgary area TMR, IBOC and LBC-SO generation has on the usage of the transmission system. These relatively recent generators have altered the usage levels of the transmission system. This Calgary area generation is effectively a substitute for transmission that should have been built between Edmonton and Calgary, but could not be built in the time frame available.
  - b. One factor that may be confusing the analysis of the peak data at the present time is the surplus generation on the system. This generation surplus can cause a major redistribution of which plants run in order to meet system load. For example, on the north south 240 kV system, the peak flows in off-peak hours are typically associated with low pool prices. Since much of the Calgary area generation has a high marginal cost, when AIL load is low, the Calgary area is typically supplied from low marginal cost generation near Edmonton or further north. The generation configuration loads up the north south transmission system in off-peak hours. When combined with exports, this results in relatively high flows in off peak hours. However, as the

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<sup>5</sup> It is possible, but highly improbable, that a transmission line in any given year will experience an outage of an element that results in transmission flows for at least one hour that reflects the worst contingency possible in terms of stressing that transmission line.

generation surplus declines, combined with Calgary area load increases and rising pool prices, the Calgary area generation will run more in both on-peak and off-peak hours and north south flows could peak in on-peak hours (including shoulder hours). As this occurs, the AESO transmission usage analysis will then show a better correlation between AIL on peak periods and peaks on the north south 240 kV system.

- c. Even if the changes in the north south corridor are permanent (i.e. Calgary area generation), the AESO has apparently placed no weight on transmission flows that would have been in place in the 1970s and 1980s when the north south corridor was being developed.
- d. Examination of individual lines will not provide as useful an analysis as an examination of transmission paths. Individual line flows in a transmission path may vary whereas the sum of the flows in a transmission path can provide a more accurate picture of the system's response to overall changes in load levels. TransCanada's initial analysis of the Calgary to Lethbridge path has resulted in flows that appear to not be possible.
- e. The data used by the AESO includes non-firm exports. These exports should be removed from any analysis as no transmission has been built for these loads. If there is any stress on the transmission system, these loads are curtailed. Put simply, non-firm exports have not historically caused any costs to be incurred. The recent 500 kV North South upgrade was planned by setting exports to zero.
- f. It is TransCanada's experience that almost all exports from Alberta occur in off-peak hours. The Cost Causation Update of the North South system did not remove exports but planners (per the AESO's own evidence) say exports drive peaks in off-peak hours.<sup>6</sup> If off-peak hours were just as stressed as on peak hours, this would suggest that exports could be added in almost any hour of the day, which does not occur.
- g. The Cost Causation Update provides no correction for flows during abnormal system conditions including plant shut-downs and transmission line outages. The system is planned by placing all elements in service and then tested to see if it meets the reliability criteria (such as N-1 or N-2 contingencies). The way the existing system is operated in any given hour can be significantly different than the way the system was planned as planning criteria are not the same as operating criteria.

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<sup>6</sup> 2006 Transmission Cost Causation Update, July 4, 2006 – DRAFT, prepared by PS Technologies, page 11

**Recommendation:**

Based on the concerns raised above, TransCanada recommends that the AESO should commission a full cost of service study in support of the recommended changes. The cost of service study should address the concerns raised in this letter in addition to others raised by other stakeholders.

If you have any questions, please contact me at 920-2092 or Dan Levson at 920-2095.

Yours truly,

**TRANSCANADA ENERGY LTD.**

Cheryl L. Terry  
Director, Market Services

cc. Dan Levson - TransCanada  
Chris Best - TransCanada