

Stakeholder Comments
AESO 2006 Cost Causation Study: Preliminary Report
May 10, 2006

Written comments were received from:

ADC

ATCO Electric

EnCana

EPCOR

IPCAA

Kinder Morgan

City of Medicine Hat

Cities of Red Deer & Lethbridge

TransAlta

TransCanada



Mr. John Martin
Manager, Regulatory
2500, 330-5th Ave S.W.
Calgary, AB T2P 0L4

May 9, 2006

Re: AESO 2007 Tariff – 2006 Cost Causation Study Preliminary Report

Dear Mr. Martin:

This letter is in response to your solicitation for stakeholder feedback on the April 19, 2006 Preliminary Report to the AESO, prepared by PS Technologies (Preliminary Report) as well as the accompanying letter (4/19 Letter) from yourself of the same date which expressed certain “views” of the AESO based on the Preliminary Report. For reasons that we will expand upon later in this response, the ADC believes that the 4/19 Letter reaches conclusions that are not supported by the Preliminary Report, and which would, if adopted, send the wrong price signals and cause undue harm to high load factor customers, the most efficient users of the transmission system. At the very least, there is insufficient evidence to justify the changes intimated by the 4/19 Letter. To be perfectly candid, we believe that some of the views expressed in the 4/19 are at best premature, and at worst, spurious. At the end of this response, the ADC will suggest a process, which we believe, will resolve some of our concerns and facilitate the progression to a 2007 Tariff, before views become prematurely, and improperly, hardened.

In particular, the ADC is of the opinion that the Preliminary Report suffers from an oversimplified search for a correlation between stress on the bulk system, and momentary peaks of the AIS coincident demand. At the risk of overusing clichés, the Preliminary Report may be missing the forest from the trees, and the 4/19 Letter, in our view, is making “the perfect” the enemy of “the good”. The ADC realizes that, in every circumstance, coincident demand may not be perfectly correlated with the loading on a particular transmission line. Nevertheless, it is our view that it is better to be approximately right than it is to be exactly wrong. A case in point is the “conclusion” that 54.6% of bulk system costs should be classified as energy-related. The ADC could not find evidence in the Preliminary Report that purports to show that *any* portion of the fixed costs of the bulk system are, or can reasonably be expected to be, proportional to annual energy consumption – let alone *over one-half* of these fixed costs. In fact, just the opposite seems to be the case. On page 4 of the Preliminary Report it lists four factors that “drive Bulk system upgrades”, namely violation of: (a) thermal capacity; (b) operating voltage; (c) voltage drop following a contingency; and (d) stability during a disturbance. Based on our understanding of the physics of the transmission system, we cannot see how any of these four factors relate to annual energy use.

Another example of oversimplification we believe is the statement that, while the evidence does not support classification of the bulk system on either a 1 CP or an (equally weighted) 12 CP basis, there is no “clear evidence” to point to another superior method for classifying costs based on cost-causation. Even if we assume, for the sake of argument, that the premise of the statement is correct, i.e. that neither a 1 CP nor 12 CP is justified by the evidence, the conclusion that it draws is, in our opinion, overly pessimistic. The Report seems to ignore the possibility of using a seasonal CP. Instead, it seems to suggest that we ought to abandon cost causation as totally unattainable and revert to other considerations, such as expediency or “popular opinion”, as the primary guide to rate design. The ADC is unwilling to go down that route.

The ADC realizes that there are situations where increases in demand at a particular moment, and at a particular place, will not result in additional stress on a particular line. In fact, it may have just the opposite effect. For example if a line is congested, increased load at an upstream node (upstream meaning the direction from which the power is flowing) will actually relieve the congestion. We also realize that generation dispatch can also influence the flow over transmission lines, separate and apart from the actions of a particular subset of consumers. The ADC is also cognizant and sensitive to the limitations of the tariff process (such as the legislative ban on geographically differentiated rates, or the mandate to collect all transmission costs, with the exception of losses, from load rather than generation), which preclude capturing the nuances of cost causation alluded to above. Nevertheless, the ADC is not willing to abandon common sense and to regress from the progress that we feel was made in the last rate proceeding.

The ADC also finds the emphasis of the Preliminary Report on the impact of generation on the transmission loading to be misplaced. While such information may have been relevant for rate design prior to 2006, under the current paradigm the load customers are responsible for the entire cost of wires. Consequently, we do not believe it is appropriate to be giving load customers price signals based on factors over which they have no control, such as wind generation.

The ADC is not of the view that all changes to the current tariff are off the table. A good tariff can always be improved. The ADC is willing to work, in a collaborative fashion, with the AESO to better reflect cost causation in the tariff, while respecting the considerations of legislative mandates, as well as practicality and customer acceptance. In furtherance of that objective, we respectfully request the following process. The ADC has retained Dr. Rosenberg of Brubaker & Associates, Inc. (BAI) to advise them on the 2007 Tariff. The ADC requests that the AESO advise Arnie Reimer that Dr. Rosenberg, and James Dauphinais, an associate of Dr. Rosenberg, will be calling him early next week to discuss the report and request certain information. Obviously, BAI requires a more complete understanding of the methodology and data that underlies the April 19 PST Preliminary Report so that we may advance the process. In furtherance of that objective, we suggest that AESO direct Mr. Reimer to cooperate fully and comply with any reasonable requests from BAI, so as to make the study more transparent, and to enable BAI to conduct any further analysis that they feel may be relevant to the task at hand.

After a period of analysis, BAI will request a meeting, hopefully as early as the end of this month, with Mr. Reimer, John Martin, and Heidi Kirrmaier. Prior to the meeting, BAI will supply PST and the AESO with a bullet list of issues/concerns that will be the subject of the meeting. The ADC is optimistic that such a meeting will allay our concerns expressed above and will lead to a more productive and expedited hearing process. Subsequent to the Calgary meeting, the ADC expects to be in a position to issue a more complete response to the AESO to move the process forward.

Thank you for your serious consideration of our comments. We look forward to your thoughtful response.

Sincerely,

P Schubert

Vice Chair, ADC (Alberta Direct Connect Consumer Association)

AESO 2006 Cost Causation Study
April 19, 2006 Preliminary Report — Stakeholder Comment Form

Comments From: ATCO Electric
 Date: May 3, 2006
 Contact: Satar Parhar
 Phone: 780-420-5501
 E-mail: Satar.Parhar@atcoelectric.com

1. Approaches Used in Study

The preliminary study discusses the correlation of Alberta Internal Load (AIL) with factors that cause expansion of the transmission bulk system. This correlation was investigated through three approaches:

- (a) qualitative discussion with transmission system planners;
- (b) quantitative analysis of 240 kV line loads and AIL load; and
- (c) quantitative analysis of percentage of 240 kV line thermal capacity and AIL load (not yet completed).

The AESO considers these three approaches to provide an appropriate and comprehensive examination of correlation of AIL load with factors that cause expansion of the transmission bulk system.

Support
 Oppose
 Indifferent

Reasons for Stakeholder Position:

2. Weighting of Monthly Peaks

The AIL load profile is relatively flat, with the summer peak load in 2005 approximately 90% of the winter peak load. In addition, the original *Transmission Cost Causation Study* identified that 55% of points of delivery experienced peak load conditions in the winter and 45% experienced peak load conditions in other periods. The preliminary study has also found that transmission upgrades are driven by concerns that occur both in the winter and in the summer. Given these findings, the bulk system rate design should generally provide equal weighting to all months.

Support
 Oppose
 Indifferent

Reasons for Stakeholder Position:

3. Cost Causation Conclusions for Bulk System

The preliminary study has confirmed that transmission system planning is very complex. It is not dominated by any one simple factor such as AIL peak load, but instead responds to a large number of independent factors such as generation patterns, regional loads, and summer and winter thermal capacities. Most 240 kV circuits (59 of 88, or 67%) exhibit only small correlation (Pearson's coefficients less than 0.30, either positive or negative) with AIL load. A significant number of 240 kV circuits (26 of 88, or 30%) exhibit line loading that is inversely proportional to AIL load. Given these factors, the AESO considers that cost causation does not support the recovery of bulk system costs on the basis of coincidence with AIL peak.

Support
 Oppose
 Indifferent

Reasons for Stakeholder Position:

4. Consideration of Other Rate Design Principles

The time of maximum stress on bulk system circuits does not necessarily coincide with the time of ALL peak load. The evidence does not support the classification of the bulk system in Alberta on either a 1 CP (one annual coincident peak) or 12 CP (twelve monthly coincident peaks, equally weighted) basis, nor is there clear evidence to point to another superior method of classifying costs based on cost causation. In the absence of a classification that is clearly cost driven, the AESO suggests that other rate design principles should be considered. Specifically, considerations of practicality, including simplicity, convenience, understandability, acceptability, and billing ease suggest that reverting to recovery of bulk system costs based on billing capacity should be considered.

Support
 Oppose
 Indifferent

Reasons for Stakeholder Position:

ATCO Electric believes that in designing rates, a significant weight should be given to practicality, convenience and simplicity, in the event that that a clear superior method of classifying costs can not be established.

5. Calculation of Coincident Demand Component

The original *Transmission Cost Causation Study* concluded that the bulk system should be classified 81.5% as demand-related and 18.5% as energy-related based on a minimum system analysis. The AESO then reduced the demand-related component further to reflect the coincidence of ALL peak with time of maximum stress, using a coincidence factor, based on data for the 500 kV N-S path, of 71.1%. The demand-related component became $81.5\% \times 71.1\% = 57.9\%$, and the balance (42.1%) of bulk system costs was classified as energy-related. The preliminary study has determined the average coincidence factor for all 240 kV lines to be 56%. If the coincident demand component for recovery of bulk system costs is retained in the DTS rate, it should therefore be reduced to recover only $81.5\% \times 56\% = 45.6\%$ of the bulk system costs, with the balance (54.4%) classified as energy-related.

Support
 Oppose
 Indifferent

Reasons for Stakeholder Position:

ATCO Electric supports the use of updated classification factors (based on the most recent study) in the determination of Demand and Energy related bulk system costs.

Additional Comments

Please return this form with your comments by May 3, 2006, to:

John Martin
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AESO 2006 Cost Causation Study
April 19, 2006 Preliminary Report — Stakeholder Comment Form

Comments From: EnCana Corporation
Date: April 24, 2006
Contact: Rod Crockford, Rinde Powell, Roger Belland
Phone:
E-mail:

1. Approaches Used in Study

The preliminary study discusses the correlation of Alberta Internal Load (AIL) with factors that cause expansion of the transmission bulk system. This correlation was investigated through three approaches:
(a) qualitative discussion with transmission system planners;
(b) quantitative analysis of 240 kV line loads and AIL load; and
(c) quantitative analysis of percentage of 240 kV line thermal capacity and AIL load (not yet completed).

- Support
 Oppose
 Indifferent

The AESO considers these three approaches to provide an appropriate and comprehensive examination of correlation of AIL load with factors that cause expansion of the transmission bulk system.

Reasons for Stakeholder Position:

2. Weighting of Monthly Peaks

The AIL load profile is relatively flat, with the summer peak load in 2005 approximately 90% of the winter peak load. In addition, the original *Transmission Cost Causation Study* identified that 55% of points of delivery experienced peak load conditions in the winter and 45% experienced peak load conditions in other periods. The preliminary study has also found that transmission upgrades are driven by concerns that occur both in the winter and in the summer. Given these findings, the bulk system rate design should generally provide equal weighting to all months.

- Support
 Oppose
 Indifferent

Reasons for Stakeholder Position:

The preliminary study appears to show that transmission upgrades are not generally related to either a winter-centered or summer-centered load pattern. This however does not necessarily imply that each month should be weighted equally. The key drivers to transmission upgrades appear to be related to the level of energy transactions/flows, which may or may not have an equal distribution across each month.

3. Cost Causation Conclusions for Bulk System

The preliminary study has confirmed that transmission system planning is very complex. It is not dominated by any one simple factor such as AIL peak load, but instead responds to a large number of independent factors such as generation patterns, regional loads, and summer and winter thermal capacities. Most 240 kV circuits (59 of 88, or 67%) exhibit only small correlation (Pearson's coefficients less than 0.30, either positive or negative) with AIL load. A significant number of 240 kV circuits

- X Support
 Oppose
 Indifferent

(26 of 88, or 30%) exhibit line loading that is inversely proportional to AIL load. Given these factors, the AESO considers that cost causation does not support the recovery of bulk system costs on the basis of coincidence with AIL peak.

Reasons for Stakeholder Position:

The table on pages 7-8 shows that transmission upgrades are required for various reasons with no single “cause of constraining factor” being the cause of bulk transmission upgrades. Demonstrating that most of the “causes” or “triggers” for transmission upgrades are not correlated to AIL load is sufficient to demonstrate that bulk expansions are not correlated to AIL peak load. The story should simply end there.

The Preliminary study confuses the issue in section 2.3 by then using “loading on Bulk Systems” as a proxy for “maximum stress” which is itself a proxy for the drivers of transmission upgrades. The Table on pages 7-8 show that “stress” is a malleable concept that does not necessarily correlate to the peak loading of a single path or transmission line. Therefore, there is no reason to assume that maximum loading on one circuit reflects “stress” or the cause of transmission upgrades. The preliminary study seems to take this needless detour based on the convenience and availability of data rather than relevance of this data to the issue.

4. Consideration of Other Rate Design Principles

The time of maximum stress on bulk system circuits does not necessarily coincide with the time of AIL peak load. The evidence does not support the classification of the bulk system in Alberta on either a 1 CP (one annual coincident peak) or 12 CP (twelve monthly coincident peaks, equally weighted) basis, nor is there clear evidence to point to another superior method of classifying costs based on cost causation. In the absence of a classification that is clearly cost driven, the AESO suggests that other rate design principles should be considered. Specifically, considerations of practicality, including simplicity, convenience, understandability, acceptability, and billing ease suggest that reverting to recovery of bulk system costs based on billing capacity should be considered.

- Support
- Oppose
- Indifferent

Reasons for Stakeholder Position:

The preliminary study does not estimate the “time of maximum stress”. It estimates the time of bulk loading as a (poor) proxy for maximum stress, which is misleading and wrong.

Transmission upgrades are “driven” by voltage, thermal and stability constraints during normal or n-1 operations as well as to accommodate energy flows from generation developments or a combination of the above. Clearly no single measure of peak demand relates to these factors consistently.

However, the degree to which customers continually use the transmission system reflects on the degree to which they contribute to the continual loading of the network of transmission paths and therefore to the need for upgrades. This suggests that with the absence of identifiable AIL peak drivers, transmission should be classified as AIL energy-related. E.g. When energy levels rise, constraints are more pronounced. When energy levels fall, constraints are generally less pronounced.

5. Calculation of Coincident Demand Component

The original *Transmission Cost Causation Study* concluded that the bulk system should be classified 81.5% as demand-related and 18.5% as energy-related based on a minimum system analysis. The AESO then reduced the demand-related component further to reflect the coincidence of AIL peak with time of maximum stress, using a coincidence factor, based on data for the 500 kV N-S path, of 71.1%. The demand-related component became $81.5\% \times 71.1\% = 57.9\%$, and the balance (42.1%) of bulk system costs was classified as energy-related. The preliminary study has determined the average coincidence factor for all 240 kV lines to be 56%. If the coincident demand component for recovery of bulk system costs is retained in the DTS rate, it should therefore be reduced to recover only $81.5\% \times 56\% = 45.6\%$ of the bulk system costs, with the balance (54.4%) classified as energy-related.

- Support
- Oppose
- Indifferent

Reasons for Stakeholder Position:

EnCana understands that the AESO is attempting to classify bulk costs by exception. i.e. bulk costs that can be positively identified to serve demand requirements will be classified as 'demand-related' otherwise the costs will be considered 'energy-related'. EnCana questions whether the stated calculation is a sound approach to achieving this classification by exception.

First, the method double counts the incidence in which transmission upgrades are demand-driven. This occurs because the method starts by adopting the TCCS presumption that transmission is 81.5% demand-related as justified by the "minimum system approach" of classification, which itself was based on the unqualified assumption that transmission upgrades are required to serve demand. Clearly, the summary on pages 7-8 shows that this presumption is unsound. Because transmission upgrades provide capacity, it does not imply that the capacity was needed to serve peak load.

Second, using coincidence factors to adjust the demand-related share of costs is unreasonable. Neither the preliminary study nor the AESO define the "coincidence factor" used here but we assume the AESO intends to reflect the ratio of load at time of (i.e. coincident with) maximum bulk circuit loading relative to the annual peak load. The purpose of such an adjustment is to temper the rate charged through the 'coincident to AIL peak demand' billing determinant. The ratio is however erroneous because the numerator (AIS load at time of maximum bulk load) presumes that all transmission upgrades are driven by the loading limits on a single bulk circuit. Quite simply, this ignores the nature of bulk systems as a network of circuits that are integrated to provide a reliable and secure transfer of energy. Once again, the summary on pages 7-8 shows that transmission upgrades (the so called point of "stress") are not exclusively driven by peak-demand on individual circuits.

Ideally, the AESO should simply return to the transmission upgrades as stated on pages 7-8 and observe directly the extent to which those upgrades are driven by the need to accommodate peak AIL load. When the upgrades are not required to accommodate peak load (whether single circuit or AIL peak) then they should be classified as 'energy-related'. Based on the reporting of the causes for upgrades, it would seem that the vast majority of these costs should therefore be 'energy-related'.

Additional Comments

The abbreviated nature of the preliminary study and the AESO conclusions raise concerns about the interpretation and understanding of the material. Given the somewhat technical nature of the material and the sometimes complex logic of the method proposed by the AESO there is the concern that Customers will misinterpret or misunderstand the recommendations of the AESO. Therefore EnCana strongly recommends that in future the AESO hold an open stakeholder session to review all materials and respond to questions in advance of requesting written comments.

Please return this form with your comments by May 3, 2006, to:

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Manager, Regulatory
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Fax: (403) 539-2524

AESO 2006 Cost Causation Study
April 19, 2006 Preliminary Report — Stakeholder Comment Form

Comments From: EPCOR Utilities Inc.

Date: May 3, 2006

Contact: Richard Stout

Phone: (780) 412-3017

E-mail: rstout@epcor.ca

1. Approaches Used in Study

The preliminary study discusses the correlation of Alberta Internal Load (AIL) with factors that cause expansion of the transmission bulk system.

This correlation was investigated through three approaches:

- (a) qualitative discussion with transmission system planners;
- (b) quantitative analysis of 240 kV line loads and AIL load; and
- (c) quantitative analysis of percentage of 240 kV line thermal capacity and AIL load (not yet completed).

The AESO considers these three approaches to provide an appropriate and comprehensive examination of correlation of AIL load with factors that cause expansion of the transmission bulk system.

- Support
- Oppose
- Indifferent

Reasons for Stakeholder Position: EPCOR generally supports that these three approaches would provide a high level examination of correlation between AIL load and the driving factors that cause expansion of the transmission bulk system. However, transmission planning often starts out from a regional need. Therefore, EPCOR suggests a more in-depth examination be carried out to include a similar type of correlation analysis based on regions, for example, as in North and South where these 240 kV lines served them. A Pearson coefficient can be then determined for the North region based on the correlation of 240 kV circuit loads that served the North region and the North regional peak. Similarly, a Pearson coefficient can be obtained for the South region. It is likely that the analysis based on the regions would yield better correlation results than the analysis based on the entire system. The result then concludes that transmission planning is stemmed from regional need.

2. Weighting of Monthly Peaks

The AIL load profile is relatively flat, with the summer peak load in 2005 approximately 90% of the winter peak load. In addition, the original *Transmission Cost Causation Study* identified that 55% of points of delivery experienced peak load conditions in the winter and 45% experienced peak load conditions in other periods. The preliminary study has also found that transmission upgrades are driven by concerns that occur both in the winter and in the summer. Given these findings, the bulk system rate design should generally provide equal weighting to all months.

- Support
- Oppose
- Indifferent

Reasons for Stakeholder Position: EPCOR suggests the study considers more history than just one year (2005) and the extended data be analyzed for weather normalization and determine if there are any impacts on the current result. EPCOR would consider a 5 year test period to be reasonable.

3. Cost Causation Conclusions for Bulk System

The preliminary study has confirmed that transmission system planning is very complex. It is not dominated by any one simple factor such as AIL peak load, but instead responds to a large number of independent factors such as generation patterns, regional loads, and summer and winter thermal capacities. Most 240 kV circuits (59 of 88, or 67%) exhibit only small correlation (Pearson's coefficients less than 0.30, either positive or negative) with AIL load. A significant number of 240 kV circuits (26 of 88, or 30%) exhibit line loading that is inversely proportional to AIL load. Given these factors, the AESO considers that cost causation does not support the recovery of bulk system costs on the basis of coincidence with AIL peak.

- Support
- Oppose
- Indifferent

Reasons for Stakeholder Position: EPCOR supports this conclusion as this has previously been EPCOR's position that electrical (transmission) system planning is NOT based on any single needle peak event in either a month or a year.

4. Consideration of Other Rate Design Principles

The time of maximum stress on bulk system circuits does not necessarily coincide with the time of AIL peak load. The evidence does not support the classification of the bulk system in Alberta on either a 1 CP (one annual coincident peak) or 12 CP (twelve monthly coincident peaks, equally weighted) basis, nor is there clear evidence to point to another superior method of classifying costs based on cost causation. In the absence of a classification that is clearly cost driven, the AESO suggests that other rate design principles should be considered. Specifically, considerations of practicality, including simplicity, convenience, understandability, acceptability, and billing ease suggest that reverting to recovery of bulk system costs based on billing capacity should be considered.

- Support
- Oppose
- Indifferent

Reasons for Stakeholder Position: Billing demand is a more suitable billing determinant than CP, which was developed to allocate generation costs and is unsuitable as a transmission bill determinant.. Further, EPCOR applauds the AESO for their consideration of more balanced and established rate design principles, and agrees that coincident peak is a poor billing determinant and a poor measure of transmission cost causation.

5. Calculation of Coincident Demand Component

The original *Transmission Cost Causation Study* concluded that the bulk system should be classified 81.5% as demand-related and 18.5% as energy-related based on a minimum system analysis. The AESO then reduced the demand-related component further to reflect the coincidence of AIL peak with time of maximum stress, using a coincidence factor, based on data for the 500 kV N-S path, of 71.1%. The demand-related component became $81.5\% \times 71.1\% = 57.9\%$, and the balance (42.1%) of bulk system costs was classified as energy-related. The preliminary study has determined the average coincidence factor for all 240 kV lines to be 56%. If the coincident demand component for recovery of bulk

- Support
- Oppose
- Indifferent

system costs is retained in the DTS rate, it should therefore be reduced to recover only $81.5\% \times 56\% = 45.6\%$ of the bulk system costs, with the balance (54.4%) classified as energy-related.

Reasons for Stakeholder Position: EPCOR supports that there should be more costs classified as energy-related, as the revised calculation has provided.

Additional Comments

Please return this form with your comments by May 3, 2006, to:

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Manager, Regulatory
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Phone: (403) 539-2465
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AESO 2006 Cost Causation Study
April 19, 2006 Preliminary Report — Stakeholder Comment Form

Comments From: IPCAA
Date: May 3, 2006
Contact: Ron Mikkelsen / Dan Macnamara
Phone: (250) 483-5306 / 266-6433
E-mail: consult@drazen.com / dmacnamara@shaw.ca

1. Approaches Used in Study

The preliminary study discusses the correlation of Alberta Internal Load (AIL) with factors that cause expansion of the transmission bulk system. This correlation was investigated through three approaches:

- (a) qualitative discussion with transmission system planners;
- (b) quantitative analysis of 240 kV line loads and AIL load; and
- (c) quantitative analysis of percentage of 240 kV line thermal capacity and AIL load (not yet completed).

The AESO considers these three approaches to provide an appropriate and comprehensive examination of correlation of AIL load with factors that cause expansion of the transmission bulk system.

Support
 Oppose
 Indifferent

Reasons for Stakeholder Position: The preliminary paper appears to cover one of the eight areas in the terms of reference (bulk system). The discussion of loading on various 240 kV lines implicitly gave equal weighting to all lines. Would the results differ if they were “cost-weighted”?

2. Weighting of Monthly Peaks

The AIL load profile is relatively flat, with the summer peak load in 2005 approximately 90% of the winter peak load. In addition, the original *Transmission Cost Causation Study* identified that 55% of points of delivery experienced peak load conditions in the winter and 45% experienced peak load conditions in other periods. The preliminary study has also found that transmission upgrades are driven by concerns that occur both in the winter and in the summer. Given these findings, the bulk system rate design should generally provide equal weighting to all months.

Support
 Oppose
 Indifferent

Reasons for Stakeholder Position:
It appears to be a leap for the AESO to suggest that all months should be equally weighted based on the material presented. The preliminary report did not talk about summer vs. winter peak loading on the bulk transmission circuits.
A summer peak equal to 90% of the winter peak is still a difference of almost 1000 MW. In the view of the AESO is this difference inconsequential? The previous TCCS identified winter and summer peaking PODs whereas the present preliminary report looked at circuit loading. In terms of cost causation on the bulk system, would it be correct to assume that the circuit loading is the more relevant measure? If so, then the time of peak load on various PODs is not terribly relevant to bulk transmission costs.

3. Cost Causation Conclusions for Bulk System

The preliminary study has confirmed that transmission system planning is Support

very complex. It is not dominated by any one simple factor such as AIL peak load, but instead responds to a large number of independent factors such as generation patterns, regional loads, and summer and winter thermal capacities. Most 240 kV circuits (59 of 88, or 67%) exhibit only small correlation (Pearson's coefficients less than 0.30, either positive or negative) with AIL load. A significant number of 240 kV circuits (26 of 88, or 30%) exhibit line loading that is inversely proportional to AIL load. Given these factors, the AESO considers that cost causation does not support the recovery of bulk system costs on the basis of coincidence with AIL peak.

- Oppose
- Indifferent

Reasons for Stakeholder Position:

The real question that the TCCS should be looking to answer is whether increased customer loads give rise to bulk transmission costs. While the analysis has examined the correlation of loading on paths with AIL load, would it not be logical to look at the correlation of path loading with area load? After all, the ultimate use of the analysis is to develop a rate design that passes through to customers the cost consequences of their use of the transmission system.

4. Consideration of Other Rate Design Principles

The time of maximum stress on bulk system circuits does not necessarily coincide with the time of AIL peak load. The evidence does not support the classification of the bulk system in Alberta on either a 1 CP (one annual coincident peak) or 12 CP (twelve monthly coincident peaks, equally weighted) basis, nor is there clear evidence to point to another superior method of classifying costs based on cost causation. In the absence of a classification that is clearly cost driven, the AESO suggests that other rate design principles should be considered. Specifically, considerations of practicality, including simplicity, convenience, understandability, acceptability, and billing ease suggest that reverting to recovery of bulk system costs based on billing capacity should be considered.

- Support
- Oppose
- Indifferent

Reasons for Stakeholder Position:

Further detail would be necessary to understand if the AESO proposal is consistent with the preliminary TCCS results. For example, if billing for bulk transmission reverts to billing capacity, what ratchet treatment does the AESO propose is supported by the results?

5. Calculation of Coincident Demand Component

The original *Transmission Cost Causation Study* concluded that the bulk system should be classified 81.5% as demand-related and 18.5% as energy-related based on a minimum system analysis. The AESO then reduced the demand-related component further to reflect the coincidence of AIL peak with time of maximum stress, using a coincidence factor, based on data for the 500 kV N-S path, of 71.1%. The demand-related component became $81.5\% \times 71.1\% = 57.9\%$, and the balance (42.1%) of bulk system costs was classified as energy-related. The preliminary study has determined the average coincidence factor for all 240 kV lines to be 56%. If the coincident demand component for recovery of bulk system costs is retained in the DTS rate, it should therefore be reduced to recover only $81.5\% \times 56\% = 45.6\%$ of the bulk system costs, with the balance (54.4%) classified as energy-related.

- Support
- Oppose
- Indifferent

Reasons for Stakeholder Position:

To date, there has not been a rationalization for classifying transmission costs as energy related. Rather there has been a presumption that if costs are not peak-demand related then they are energy related. If this demand/energy classification methodology is translated directly into the rate design it suggests a greater degree of cost causation is attributable to a customer with the same peak demand as another but a higher load factor. Whether or not this is the case (and whether there may be exceptions) should be addressed by the AESO.

Additional Comments

Please return this form with your comments by May 3, 2006, to:

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Fax: (403) 539-2524

AESO 2006 Cost Causation Study
April 19, 2006 Preliminary Report — Stakeholder Comment Form

Comments From: Kinder Morgan Canada Inc.
Date: May 5, 2006
Contact: Neall Banner
Phone: 514-6552
E-mail: neall_banner@kindermorgan.com:

1. Approaches Used in Study

The preliminary study discusses the correlation of Alberta Internal Load (AIL) with factors that cause expansion of the transmission bulk system. This correlation was investigated through three approaches:
(a) qualitative discussion with transmission system planners;
(b) quantitative analysis of 240 kV line loads and AIL load; and
(c) quantitative analysis of percentage of 240 kV line thermal capacity and AIL load (not yet completed).

The AESO considers these three approaches to provide an appropriate and comprehensive examination of correlation of AIL load with factors that cause expansion of the transmission bulk system.

Support
 Oppose
 Indifferent

Reasons for Stakeholder Position:

As stated in the Cost/ Causation preliminary report, transmission planning is very complex and is not dominated by one simple factor. The use of both quantitative and qualitative analysis is appropriate for such a complex system.

2. Weighting of Monthly Peaks

The AIL load profile is relatively flat, with the summer peak load in 2005 approximately 90% of the winter peak load. In addition, the original *Transmission Cost Causation Study* identified that 55% of points of delivery experienced peak load conditions in the winter and 45% experienced peak load conditions in other periods. The preliminary study has also found that transmission upgrades are driven by concerns that occur both in the winter and in the summer. Given these findings, the bulk system rate design should generally provide equal weighting to all months.

Support
 Oppose
 Indifferent

Reasons for Stakeholder Position:

The data confirms that peak loads appear at different times of the year for different points of delivery. The data suggests that the bulk system rate design should generally provide equal weighting to all months – this seems consistent with the principle of cost/ causation.

3. Cost Causation Conclusions for Bulk System

The preliminary study has confirmed that transmission system planning is very complex. It is not dominated by any one simple factor such as AIL peak load, but instead responds to a large number of independent factors such as generation patterns, regional loads, and summer and winter thermal capacities. Most 240 kV circuits (59 of 88, or 67%) exhibit

Support
 Oppose
 Indifferent

only small correlation (Pearson's coefficients less than 0.30, either positive or negative) with AIL load. A significant number of 240 kV circuits (26 of 88, or 30%) exhibit line loading that is inversely proportional to AIL load. Given these factors, the AESO considers that cost causation does not support the recovery of bulk system costs on the basis of coincidence with AIL peak.

Reasons for Stakeholder Position:

Kinder Morgan is very supportive of the AESO's methodology and conclusions drawn from this analysis. Generally, if data is analyzed and a poor correlation exists between key variables, it is proper to **not** use the analysis in determining transmission rates. Cost causation should be used as the over-guiding principle only if proper analysis shows a consistent, statistically significant relationship between rate setting variables.

4. Consideration of Other Rate Design Principles

The time of maximum stress on bulk system circuits does not necessarily coincide with the time of AIL peak load. The evidence does not support the classification of the bulk system in Alberta on either a 1 CP (one annual coincident peak) or 12 CP (twelve monthly coincident peaks, equally weighted) basis, nor is there clear evidence to point to another superior method of classifying costs based on cost causation. In the absence of a classification that is clearly cost driven, the AESO suggests that other rate design principles should be considered. Specifically, considerations of practicality, including simplicity, convenience, understandability, acceptability, and billing ease suggest that reverting to recovery of bulk system costs based on billing capacity should be considered.

- Support
- Oppose
- Indifferent

Reasons for Stakeholder Position:

Kinder Morgan agrees with the AESO that in the absence of statistically significant method of classifying costs, other rate principles should apply. In addition to the principles mentioned by the AESO, Kinder Morgan suggests that the following principles should also be considered:

- minimizing rate shock and mitigating the impact of large increases in transmission tariff charges,
- fairness of rates to new and existing customers, including the fair allocation of costs,
- Minimizing the impact of changing economic signals after customers have committed to constructing facilities

Kinder Morgan is also supportive of the efforts of the AESO in researching tariff allocation methods from other jurisdictions. The lessons learned in other jurisdictions should provide guidance to the AESO in designing rates that create the right economic signals.

5. Calculation of Coincident Demand Component

The original *Transmission Cost Causation Study* concluded that the bulk system should be classified 81.5% as demand-related and 18.5% as energy-related based on a minimum system analysis. The AESO then reduced the demand-related component further to reflect the coincidence of AIL peak with time of maximum stress, using a coincidence factor, based on data for the 500 kV N-S path, of 71.1%. The demand-related component became $81.5\% \times 71.1\% = 57.9\%$, and the balance (42.1%) of bulk system costs was classified as energy-related. The preliminary

- Support
- Oppose
- Indifferent

study has determined the average coincidence factor for all 240 kV lines to be 56%. If the coincident demand component for recovery of bulk system costs is retained in the DTS rate, it should therefore be reduced to recover only $81.5\% \times 56\% = 45.6\%$ of the bulk system costs, with the balance (54.4%) classified as energy-related.

Reasons for Stakeholder Position:

Additional Comments

Kinder Morgan thanks the AESO for the opportunity of providing early comments on the cost causation study.

Please return this form with your comments by May 3, 2006, to:

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AESO 2006 Cost Causation Study
April 19, 2006 Preliminary Report — Stakeholder Comment Form

Comments From: City of Medicine Hat
Date: May 3, 2006
Contact: Douglas Crichton
Phone: (403) 529 8365
E-mail: doucri@medicinehat.ca

1. Approaches Used in Study

The preliminary study discusses the correlation of Alberta Internal Load (AIL) with factors that cause expansion of the transmission bulk system. This correlation was investigated through three approaches:
(a) qualitative discussion with transmission system planners;
(b) quantitative analysis of 240 kV line loads and AIL load; and
(c) quantitative analysis of percentage of 240 kV line thermal capacity and AIL load (not yet completed).

The AESO considers these three approaches to provide an appropriate and comprehensive examination of correlation of AIL load with factors that cause expansion of the transmission bulk system.

Support
 Oppose
 Indifferent

Reasons for Stakeholder Position:

2. Weighting of Monthly Peaks

The AIL load profile is relatively flat, with the summer peak load in 2005 approximately 90% of the winter peak load. In addition, the original *Transmission Cost Causation Study* identified that 55% of points of delivery experienced peak load conditions in the winter and 45% experienced peak load conditions in other periods. The preliminary study has also found that transmission upgrades are driven by concerns that occur both in the winter and in the summer. Given these findings, the bulk system rate design should generally provide equal weighting to all months.

Support
 Oppose
 Indifferent

Reasons for Stakeholder Position:

Summer load from irrigation and air-conditioning in the south of the province is significantly different than winter consumption. Rate design that has an objective of reducing the peaks needs to recognize they are monthly or at least seasonal. CMH does not agree that bulk system rate design should generally provide equal weighting to all months.

3. Cost Causation Conclusions for Bulk System

The preliminary study has confirmed that transmission system planning is very complex. It is not dominated by any one simple factor such as AIL peak load, but instead responds to a large number of independent factors such as generation patterns, regional loads, and summer and winter thermal capacities. Most 240 kV circuits (59 of 88, or 67%) exhibit only small correlation (Pearson's coefficients less than 0.30, either positive or negative) with AIL load. A significant number of 240 kV circuits

Support
 Oppose
 Indifferent

(26 of 88, or 30%) exhibit line loading that is inversely proportional to AIL load. Given these factors, the AESO considers that cost causation does not support the recovery of bulk system costs on the basis of coincidence with AIL peak.

Reasons for Stakeholder Position:

Notwithstanding study results and that transmission system planning is complex and factors lack correlation with AIL peakloads, it remains intuitive that a rate design that has an objective that serves to reduce demand peaks should be supported (or not discounted).

4. Consideration of Other Rate Design Principles

The time of maximum stress on bulk system circuits does not necessarily coincide with the time of AIL peak load. The evidence does not support the classification of the bulk system in Alberta on either a 1 CP (one annual coincident peak) or 12 CP (twelve monthly coincident peaks, equally weighted) basis, nor is there clear evidence to point to another superior method of classifying costs based on cost causation. In the absence of a classification that is clearly cost driven, the AESO suggests that other rate design principles should be considered. Specifically, considerations of practicality, including simplicity, convenience, understandability, acceptability, and billing ease suggest that reverting to recovery of bulk system costs based on billing capacity should be considered.

- Support
- Oppose
- Indifferent

Reasons for Stakeholder Position:

The rate design changes to include cost recovery based in part on CP billing have already been implemented. Why change again based on lack of evidence that points to a superior method based on cost causation. CMH does not support reverting to recovery of bulk system costs based on billing capacity.

5. Calculation of Coincident Demand Component

The original *Transmission Cost Causation Study* concluded that the bulk system should be classified 81.5% as demand-related and 18.5% as energy-related based on a minimum system analysis. The AESO then reduced the demand-related component further to reflect the coincidence of AIL peak with time of maximum stress, using a coincidence factor, based on data for the 500 kV N-S path, of 71.1%. The demand-related component became $81.5\% \times 71.1\% = 57.9\%$, and the balance (42.1%) of bulk system costs was classified as energy-related. The preliminary study has determined the average coincidence factor for all 240 kV lines to be 56%. If the coincident demand component for recovery of bulk system costs is retained in the DTS rate, it should therefore be reduced to recover only $81.5\% \times 56\% = 45.6\%$ of the bulk system costs, with the balance (54.4%) classified as energy-related.

- Support
- Oppose
- Indifferent

Reasons for Stakeholder Position:

For City of Medicine Hat, a rate design to recover costs based 100% on energy related is most suitable. One based on 100% billing capacity is least suitable. Any move to increase recovery thru energy-related billing is supported.

The logo for CHYMKO, featuring the word "CHYMKO" in white, bold, uppercase letters on a red rectangular background.

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May 3, 2006

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

Dear Mr. Martin

SUBJECT: AESO 2006 Preliminary Cost of Service Report

In response to your April 19th letter, I am responding on behalf of the Cities of Red Deer and Lethbridge to your invitation for comment. The Cities have reviewed the PS Technologies report and are encouraged by the AESO's efforts to rationalize and justify key components of its tariff.

We do not have any comments or questions at this time, but look forward to the final report as well as the AESO's recommendation as to how the results will be incorporated into its 2007 tariff application.

Sincerely,

<sent by email>

Nigel Chymko
President

AESO 2006 Cost Causation Study
April 19, 2006 Preliminary Report — Stakeholder Comment Form

Comments From: TransCanada
 Date: May 4, 2006
 Contact: Cheryl Terry/ Dan Levson
 Phone: 920-2092 / 920-2095
 E-mail: Cheryl_Terry@transcanada/ Dan_Levson@transcanada.com

1. Approaches Used in Study

The preliminary study discusses the correlation of Alberta Internal Load (AIL) with factors that cause expansion of the transmission bulk system. This correlation was investigated through three approaches:

- (a) qualitative discussion with transmission system planners;
- (b) quantitative analysis of 240 kV line loads and AIL load; and
- (c) quantitative analysis of percentage of 240 kV line thermal capacity and AIL load (not yet completed).

The AESO considers these three approaches to provide an appropriate and comprehensive examination of correlation of AIL load with factors that cause expansion of the transmission bulk system.

Support
 Oppose
 Indifferent

Reasons for Stakeholder Position: TransCanada supports item (a) above. Item (c) above is not yet completed, so no comment is offered.

Regarding item (b), requiring “the quantitative analysis of 240 kV loads and AIL load”, the AESO report appears to have interpreted this to mean the correlation between 240 kV loads and the AIL peak load. The AIL peak load occurs in one hour and due to the complex nature of the transmission system, there will be few if any lines that exactly peak at the time of the AIL peak. The report acknowledges that “a number of lines are near their peak load during the hour of annual AIL peak.” It is also possible that an even greater number of lines peak during AIL peak loads that are close to the AIL annual peak, but are not peaking at that exact hour.

2. Weighting of Monthly Peaks

The AIL load profile is relatively flat, with the summer peak load in 2005 approximately 90% of the winter peak load. In addition, the original *Transmission Cost Causation Study* identified that 55% of points of delivery experienced peak load conditions in the winter and 45% experienced peak load conditions in other periods. The preliminary study has also found that transmission upgrades are driven by concerns that occur both in the winter and in the summer. Given these findings, the bulk system rate design should generally provide equal weighting to all months.

Support
 Oppose
 Indifferent

Reasons for Stakeholder Position: TransCanada has difficulty accepting the AESO’s logic on this point. The analysis does not differentiate PODs by size, presumably counting one POD equally with others. For example, does a small POD serving summer peaking irrigation load get the same weight as a POD serving a winter peaking refinery load? Also, from TransCanada’s experience, the peak loads are more likely in July, August, November, December and January. There may be approximately 50 to 100 peak hours that are the real drivers for new transmission lines (after adjusting for opportunity sales and abnormal system

conditions). If the bulk of these peaks occur in the months noted, then a coincident peak taken from those five months may be fairly indicative of true cost causation. It is not clear to TransCanada if “other periods” include spring and fall months or only summer months. TransCanada recommends summer, winter, spring and fall months be defined.

3. Cost Causation Conclusions for Bulk System

The preliminary study has confirmed that transmission system planning is very complex. It is not dominated by any one simple factor such as AIL peak load, but instead responds to a large number of independent factors such as generation patterns, regional loads, and summer and winter thermal capacities. Most 240 kV circuits (59 of 88, or 67%) exhibit only small correlation (Pearson’s coefficients less than 0.30, either positive or negative) with AIL load. A significant number of 240 kV circuits (26 of 88, or 30%) exhibit line loading that is inversely proportional to AIL load. Given these factors, the AESO considers that cost causation does not support the recovery of bulk system costs on the basis of coincidence with AIL peak.

Support
 Oppose
 Indifferent

Reasons for Stakeholder Position:

While the report acknowledges the importance of opportunity imports and exports, the report needs more clarity around the issue of the cost causation drivers for new transmission (which are typically peak loads on a given transmission line for a given area of the province) versus how the transmission system is actually operated. Opportunity service loads such as imports, exports and DOS loads substantially affect the transmission flows being used in the AESO report but are not included when planning for new transmission. Exports in off-peak hours partially explain why the system peaks in the off-peak hours on the north south transmission path. Removal of the effect of exports could result in peaks occurring in on-peak hours.

While not clearly a part of the scope, the correlation of customer POD level peaks to the 240 kV load peaks is an important correlation given that POD level demands is another potential billing mechanism and has been used historically. TransCanada draws a distinction between 240 kV lines that are bulk in nature (Edmonton to Calgary, Edmonton area to Ft. McMurray) and those that are more localized in nature, including those designed to interconnect generation such as the Sheerness plants. Consideration should be given to treating these separately to recognize significant differences in cost per line and in their general purpose. While it is recognized that the transmission system is complex, the purpose of conducting a cost of service study is to identify patterns and key cost drivers that (1) may be obscured in complexity and (2) are exceptions to the general pattern.

4. Consideration of Other Rate Design Principles

The time of maximum stress on bulk system circuits does not necessarily coincide with the time of AIL peak load. The evidence does not support the classification of the bulk system in Alberta on either a 1 CP (one annual coincident peak) or 12 CP (twelve monthly coincident peaks, equally weighted) basis, nor is there clear evidence to point to another superior method of classifying costs based on cost causation. In the absence of a classification that is clearly cost driven, the AESO suggests that other rate design principles should be considered. Specifically, considerations of practicality, including simplicity, convenience,

Support
 Oppose
 Indifferent

understandability, acceptability, and billing ease suggest that reverting to recovery of bulk system costs based on billing capacity should be considered.

Reasons for Stakeholder Position:

TransCanada is not convinced that the review of the input from planners in combination with load flows that are adjusted to remove all types of opportunity service loads (EOS, IOS, DOS) would not lead to the conclusion that transmission lines are caused by peak AIL loads for bulk transmission paths and by a combination of peak AIL loads and local POD level loads for more localized 240 kV lines. Monthly peak AIL loads, while not necessarily grouped into 12 months, could be reasonably represented by about 5 monthly peak loads.

Given that the AESO has not proposed a specific alternative, TransCanada is currently indifferent. However, adoption of an energy intensive approach and setting aside longstanding use of demand-intensive pricing that reflects the largely fixed nature of transmission costs would not be supported by TransCanada. TransCanada would not support that “simplicity, convenience, understandability, acceptability, and billing ease” justifies such a radical pricing change.

5. Calculation of Coincident Demand Component

The original *Transmission Cost Causation Study* concluded that the bulk system should be classified 81.5% as demand-related and 18.5% as energy-related based on a minimum system analysis. The AESO then reduced the demand-related component further to reflect the coincidence of AIL peak with time of maximum stress, using a coincidence factor, based on data for the 500 kV N-S path, of 71.1%. The demand-related component became $81.5\% \times 71.1\% = 57.9\%$, and the balance (42.1%) of bulk system costs was classified as energy-related. The preliminary study has determined the average coincidence factor for all 240 kV lines to be 56%. If the coincident demand component for recovery of bulk system costs is retained in the DTS rate, it should therefore be reduced to recover only $81.5\% \times 56\% = 45.6\%$ of the bulk system costs, with the balance (54.4%) classified as energy-related.

- Support
- Oppose
- Indifferent

Reasons for Stakeholder Position: TransCanada is concerned that the outcome of a 54.4% energy-related pricing mechanism is counter-intuitive for a transmission system that is largely fixed in nature. Examination of the filings used to justify new transmission lines for loads confirms that it is new loads that drive the need for new transmission, not more energy transported at the same peak load (i.e. higher load factor). While the transmission system addresses more than just peak loads and provides reliability services when specific transmission lines are down, it is still generally true that the amount of redundancy on a transmission system will be affected by the amount of energy transmitted. For example, if three 240 kV lines are required to reliably transmit 600 MW of peak load, then six 240 kV lines will likely be required to transport 1200 MW of peak load, regardless of the load factor. Put another way, the redundancy of transmission to meet N-1 contingencies is not materially affected by load factor, but it could be affected by the total number of lines in a transmission path.

TransCanada is also concerned there may be some double-counting between the minimum system analysis and the application of the 71.1% coincidence factor. TransCanada does not

support the use of the minimum system analysis for a Transmission cost study. The minimum system analysis is a method used only in Distribution cost studies elsewhere in the world.

Additional Comments

TransCanada recommends the AESO conduct a small work session with experts in the cost of service and transmission planning areas to minimize hearing time, identify best practices in conducting cost of service studies and minimize confusion on terminology.

Please return this form with your comments by May 3, 2006, to:

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Manager, Regulatory
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Phone: (403) 539-2465
Fax: (403) 539-2524

AESO 2006 Cost Causation Study
April 19, 2006 Preliminary Report — Stakeholder Comment Form

Comments From: TransAlta Corporation
Date: 2006/04/28
Contact: Jim Paton
Phone: 267-7522
E-mail: jpaton@transalta.com

1. Approaches Used in Study

The preliminary study discusses the correlation of Alberta Internal Load (AIL) with factors that cause expansion of the transmission bulk system. This correlation was investigated through three approaches:
(a) qualitative discussion with transmission system planners;
(b) quantitative analysis of 240 kV line loads and AIL load; and
(c) quantitative analysis of percentage of 240 kV line thermal capacity and AIL load (not yet completed).

Support
 Oppose
 Indifferent

The AESO considers these three approaches to provide an appropriate and comprehensive examination of correlation of AIL load with factors that cause expansion of the transmission bulk system.

Reasons for Stakeholder Position:

Not enough evidence yet to support the statement that the three approaches are all encompassing and therefore comprehensive enough. History has played a large part in the system as it now exists. Generation was located near the fuel source and the transmission was built to transmit from the generator to the load. The same is true today for the wind sites.

2. Weighting of Monthly Peaks

The AIL load profile is relatively flat, with the summer peak load in 2005 approximately 90% of the winter peak load. In addition, the original *Transmission Cost Causation Study* identified that 55% of points of delivery experienced peak load conditions in the winter and 45% experienced peak load conditions in other periods. The preliminary study has also found that transmission upgrades are driven by concerns that occur both in the winter and in the summer. Given these findings, the bulk system rate design should generally provide equal weighting to all months.

Support
 Oppose
 Indifferent

Reasons for Stakeholder Position:

As discussed above the monthly peak loads are not a key cause of the need to invest in bulk system additions.

3. Cost Causation Conclusions for Bulk System

The preliminary study has confirmed that transmission system planning is very complex. It is not dominated by any one simple factor such as AIL peak load, but instead responds to a large number of independent factors such as generation patterns, regional loads, and summer and winter thermal capacities. Most 240 kV circuits (59 of 88, or 67%) exhibit only small correlation (Pearson's coefficients less than 0.30, either positive or negative) with AIL load. A significant number of 240 kV circuits

Support
 Oppose
 Indifferent

(26 of 88, or 30%) exhibit line loading that is inversely proportional to ALL load. Given these factors, the AESO considers that cost causation does not support the recovery of bulk system costs on the basis of coincidence with ALL peak.

Reasons for Stakeholder Position: As above.

4. Consideration of Other Rate Design Principles

The time of maximum stress on bulk system circuits does not necessarily coincide with the time of ALL peak load. The evidence does not support the classification of the bulk system in Alberta on either a 1 CP (one annual coincident peak) or 12 CP (twelve monthly coincident peaks, equally weighted) basis, nor is there clear evidence to point to another superior method of classifying costs based on cost causation. In the absence of a classification that is clearly cost driven, the AESO suggests that other rate design principles should be considered. Specifically, considerations of practicality, including simplicity, convenience, understandability, acceptability, and billing ease suggest that reverting to recovery of bulk system costs based on billing capacity should be considered.

Support
 Oppose
 Indifferent

Reasons for Stakeholder Position: TransAlta tentatively supports consideration of billing capacity for recovery of bulk system costs but more evidence is required to support this proposition.

5. Calculation of Coincident Demand Component

The original *Transmission Cost Causation Study* concluded that the bulk system should be classified 81.5% as demand-related and 18.5% as energy-related based on a minimum system analysis. The AESO then reduced the demand-related component further to reflect the coincidence of ALL peak with time of maximum stress, using a coincidence factor, based on data for the 500 kV N-S path, of 71.1%. The demand-related component became $81.5\% \times 71.1\% = 57.9\%$, and the balance (42.1%) of bulk system costs was classified as energy-related. The preliminary study has determined the average coincidence factor for all 240 kV lines to be 56%. If the coincident demand component for recovery of bulk system costs is retained in the DTS rate, it should therefore be reduced to recover only $81.5\% \times 56\% = 45.6\%$ of the bulk system costs, with the balance (54.4%) classified as energy-related.

Support
 Oppose
 Indifferent

Reasons for Stakeholder Position: The 56% factor suggests that coincident demand probably should not be the demand recovery component. Using a single hour from a single year to indicate coincidence and to use such for rates is superficial and in our view is not a robust approach to determining coincidence considering rate stability concerns.

Additional Comments

Under 2.1 the comment is made that “the transmission system in southern Alberta is not constrained in the winter time.” For clarity we suggest inserting the words “240 kV” before the word transmission. Under 2.2 in the table the comment is made repeatedly that “Wind generation is not correlated to AIL Load”. There is nothing in the study which shows this analysis. We would suggest that such analysis should also be done for all generating plants as we expect that they would show low correlations with the exception of hydro to AIL Load. See below for January 2006 with hourly system demand versus various generating plants.

Please return this form with your comments by May 3, 2006, to:

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