



May 31, 2006

Sent via e-mail

AESO Stakeholders
AESO 2007 General Tariff Application

Dear Stakeholder:

Re: 2006 Cost Causation Study Preliminary Report — AESO Responses to Stakeholder Comments

On April 19, 2006, the AESO distributed a preliminary report on the 2006 Cost Causation Study being completed as part of preparations for its 2007 tariff application, and invited stakeholder comments on the report. The AESO received comments from the Alberta Direct Connect Consumer Association (ADC), ATCO Electric, EnCana Corporation, EPCOR, the Industrial Power Consumers Association of Alberta (IPCAA), Kinder Morgan Canada, City of Medicine Hat, Cities of Red Deer and Lethbridge, TransAlta Corporation, and TransCanada.

Stakeholders expressed a variety of comments on the preliminary report itself and on the AESO's views provided in the update letter distributed with the report. In reply to those comments the AESO offers the following general remarks as well as more specific responses in the attached matrix.

- (a) The 2006 Cost Causation Study is being prepared in response to Directions 4C and 5A in EUB Decision 2005-096 and in accordance with the terms of reference for the study as revised on February 19, 2006. As part of the study, activities are being conducted to investigate certain aspects of cost causation on the transmission system. The preliminary report provides findings on one of those activities, as the AESO wished to offer stakeholders the opportunity to provide early input for further work before finalizing conclusions from the study.
- (b) The bulk system coincident demand charge in the 2006 DTS rate recovers about 25% of transmission system costs. Some stakeholders indicate that the charge should be further differentiated, for example, into regional, monthly, or seasonal components. The AESO suggests that one of the goals of cost causation-based rate design is providing a clear price signal that results in customer behaviour which reduces cost. Dividing the DTS charge into ever-smaller components would weaken the price signal. The resulting price signal could eventually become so weak or fractured that no practical customer response would be encouraged, and even if a response occurs it results only in costs being shifted between customers rather than actually being reduced.

- (c) Some stakeholders suggested analysis of regional load coincidence with bulk system stress would provide higher correlation factors. The AESO agrees that bulk system lines are planned to meet constraints on specific paths (as discussed on pages 7-8 of the preliminary report), but does not see how such a relationship could be reflected in a “postage stamp” transmission rate. The AESO is not aware of any practical means of implementing a “coincident regional peak” billing determinant. Furthermore, the qualitative discussion in the preliminary report did assess the factors considered in the planning of individual bulk system lines, and demonstrated that transmission planning is not dominated by any one simple factor such as peak load. Finally, the AESO suggests that any regional analysis would be subject to continual debate over appropriate boundaries for the regions, and would not provide a clear and transparent pricing signal.
- (d) Some stakeholders interpreted comments in the preliminary report as indicating that the study examined bulk system loading during the single hour of AIL peak. The study examined all 8,760 hours of load on each 240 kV line during the year to establish whether there was a relationship between line load and AIL.

The AESO is continuing work on the 2006 Cost Causation Study in accordance with the terms of reference developed for it. The AESO will be preparing a final report for distribution and comment in mid-June, and expects to hold a stakeholder workshop to review the findings and final conclusions at that time. Details on the workshop will be distributed when release of the final report has been scheduled.

If you wish to provide further comments on the preliminary report or on the 2007 rates consultation to date, you can send them at any time to John Martin at john.martin@aeso.ca. If you have questions on the 2007 tariff consultation, please contact John Martin at (403) 539-2465 or Ed Hucman at (403) 539-2469 (both in Calgary) or by e-mail to john.martin@aeso.ca or ed.hucman@aeso.ca.

All information on the 2007 tariff consultation is available on the AESO’s website at www.aeso.ca by following the paths:

- Tariff ► Current Consultations ► 2007 Rates, and
- Tariff ► Current Consultations ► 2007 Terms and Conditions.

Yours truly,

[original signed by]

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**AESO 2006 Cost Causation Study Preliminary Report Response Matrix
Stakeholder Comments and AESO Responses — May 31, 2006**

AESO Proposal	Stakeholder Comment	AESO Response
1. Approaches Used in Study		
<p>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:</p> <ul style="list-style-type: none"> (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). <p>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.</p>	<p>ADC – Position not indicated 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.</p> <p>ATCO Electric – Support</p> <p>EnCana – Position not indicated</p> <p>EPCOR – Support 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.</p> <p>IPCAA – Indifferent The preliminary paper appears to cover one of the eight areas in the terms</p>	<p>It is unclear what is meant by high load factor customers being the “most efficient users” of the transmission system. If the term indicates continuous load on the transmission system, then such loads will contribute to maximum stress no matter when that stress occurs and will offer no benefits of load diversity. The AESO agrees that the cost causation study is not yet complete. The stakeholder comments received to date will ensure that all concerns are effectively reviewed before the tariff application is filed.</p> <p>Please refer to comments in point (c) of the AESO’s response letter.</p> <p>Please refer to comments in point (a) of</p>

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	<p>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”?</p> <p>Kinder Morgan – Support 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.</p> <p>Medicine Hat – Indifferent</p> <p>TransAlta – Oppose 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.</p> <p>TransCanada – (a) Support, (b) Oppose, (c) Position not indicated 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.</p>	<p>the AESO’s response letter. Weighting of lines by length (as a proxy for costs) will be examined to determine if results would be materially affected.</p> <p>If the proposed approaches are not comprehensive, the AESO would appreciate suggestions of additional approaches that would address bulk system cost causation.</p> <p>Please refer to comments in point (d) of the AESO’s response letter. The AESO will investigate line loading during the hours near the AIL annual peak to see if additional insights may be gained.</p>
2. Weighting of Monthly Peaks		
<p>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 <i>Transmission Cost Causation Study</i> identified that 55% of points of delivery experienced</p>	<p>ATCO Electric – Support</p> <p>EnCana – Position not indicated The preliminary study appears to show that transmission upgrades are <u>not</u> 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</p>	<p>As indicated in the table on page 8 of the preliminary report, winter loads in the northwest are currently driving bulk system upgrades in the northwest. As well, summer loads in the south have</p>

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<p>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.</p>	<p>distribution across each month.</p> <p>EPCOR – Oppose 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.</p> <p>IPCAA – Oppose 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.</p> <p>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.</p>	<p>historically driven transmission upgrades in the south. As generation locates in different areas of the province, simple correlations such as these are becoming less common.</p> <p>In general, for the bulk transmission system, year-over-year loading is stable and affected more by major load and generation additions than by weather. Two years of actual system data are generally used when reviewing system loading and data is not normalized for weather. Given the stability of bulk system loading and the low correlation demonstrated by 2005 data, the AESO would not expect an additional year's data would affect conclusions or be a productive use of time and resources.</p> <p>The preliminary report does discuss how bulk lines in the southern part of Alberta experience constraining factors in the summer, and in the northern part of Alberta experience constraining factors in the winter.</p> <p>Please refer to comments in point (c) of the AESO's response letter.</p> <p>The AESO considers that differentiating a rate component to address a seasonal difference of 10% would likely not impact customer behaviour compared to a non-differentiated rate. Furthermore, reducing the already small seasonal gap (for example, such that the system load in every month is 95% of the current winter peak) would provide minimal system benefits or cost reductions.</p> <p>The AESO agrees that POD peaks</p>

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	<p>Kinder Morgan – Support 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.</p> <p>Medicine Hat – Oppose 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.</p> <p>TransAlta – Support As discussed above the monthly peak loads are not a key cause of the need to invest in bulk system additions.</p> <p>TransCanada – Oppose 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.</p>	<p>do not necessarily cause system peaks, but the seasonal variation in POD peaks is consistent with the findings on bulk circuit loading.</p> <p>Please refer to comments in point (b) of the AESO’s response letter. The AESO agrees that rate design should not be generalized to equal weighting where substantial benefits can be expected from seasonal or monthly differentiation. However, this does not appear to be the case in Alberta.</p> <p>Please refer to comments in point (b) of the AESO’s response letter and to the AESO’s response to IPCAA’s comments above. As noted in the Preliminary Report, constraints other than peak loading frequently drive bulk system upgrades – factors like voltage constraints and system stability.</p>

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3. Cost Causation Conclusions for Bulk System		
<p>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.</p>	<p>ATCO Electric – Support</p> <p>EnCana – Support</p> <p>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.</p> <p>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 shows 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.</p> <p>EPCOR – Support</p> <p>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.</p> <p>IPCAA – Indifferent</p> <p>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.</p>	<p>Please refer to comments in point (a) of the AESO's response letter. The AESO considers that reaching conclusions based on a qualitative discussion only would neither satisfy EUB directions nor stakeholder concerns.</p> <p>Although maximum stress is not synonymous with maximum load, maximum stress typically does occur when transmission system components are heavily loaded (as discussed in response to ADC Request 4). However, the AESO's 2006 tariff recovers bulk system costs based neither on transmission component maximum stress nor maximum load, but on maximum load <i>for the total system</i>. The analysis in section 2.3 examines the validity of this approach.</p> <p>The AESO agrees that system planning is not based on load in a single hour in a month or year. However, if a correlation exists between the bulk line load for which a system is planned and the total system load, then it may have merit to recover costs on coincidence with total system load.</p> <p>The differentiation of system costs into bulk and local functions in the original Transmission Cost Causation Study was based on the bulk system delivering energy over long distances to many users, while the local system met the needs of local area loads. The 240 kV system generally satisfies the</p>

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	<p>Kinder Morgan – Support 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.</p> <p>Medicine Hat – Oppose Notwithstanding study results and that transmission system planning is complex and factors lack correlation with AIL peak loads, it remains intuitive that a rate design that has an objective that serves to reduce demand peaks should be supported (or not discounted).</p> <p>TransAlta – Support As above.</p> <p>TransCanada – Oppose 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.</p>	<p>bulk function definition, and includes the capability of carrying electricity into or out of an area.</p> <p>As discussed in point (b) of the AESO’s response letter, the AESO agrees that rate design should pass cost consequences to customers. If coincidence with total system peak has no cost consequence (or, conversely, if avoidance of system peak provides no cost benefit), then a rate design based on peak coincidence is not appropriate.</p> <p>The AESO suggests that “intuitive” results must align with qualitative and quantitative analysis or else should be discounted. Please refer to comments in point (b) of the AESO’s response letter.</p> <p>The Transmission Regulation requires the AESO to plan a transmission system that accommodates loads, imports, exports, and in-merit generation, with no distinctions relating to opportunity service. As well, the nature of the bulk system makes it virtually impossible to remove opportunity services from energy flows used for coincidence analysis. As</p>

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	<p>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.</p>	<p>opportunity service, by definition, is available only when sufficient transmission capacity exists, opportunity service should not identifiably contribute to periods of maximum stress on the transmission system.</p> <p>The Preliminary Report also discussed that bulk system drivers are thermal, voltage, and stability constraints, and that maximum stress on individual bulk system circuits frequently occur at times other than system peak.</p> <p>The AESO agrees that billing capacity (which reflects POD-level demands) may be an appropriate determinant on which to recover bulk system costs, as discussed in item 4 of the AESO's April 19 update letter. Please see response to IPCAA above for comments on bulk system and local system distinctions. The AESO will examine whether 240 kV lines which primarily interconnect generation should be included in the cost classification analysis. (Such lines will continue to be functionalized as bulk system in any event.)</p>
4. Consideration of Other Rate Design Principles		
<p>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,</p>	<p>ADC – Position not indicated</p> <p>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</p>	<p>The AESO considers it appropriate to retain the demand and energy components of the bulk system to reflect cost causation as examined in the original Transmission Cost Causation Study. The question being pursued in the Preliminary Report is which of the available demand billing determinants (including contract</p>

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<p>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.</p>	<p>considerations, such as expediency or “popular opinion”, as the primary guide to rate design. The ADC is unwilling to go down that route.</p> <p>ATCO Electric – Support ATCO Electric believes that in designing rates, a significant weight should be given to practicality, convenience and simplicity, in the event that a clear superior method of classifying costs can not be established.</p> <p>EnCana – Position not indicated 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.</p>	<p>demand, non-coincident peak, and coincident peak, with various ratchet and minimum provisions) should be used to recover demand-related costs? The initial analysis does not appear to support recovering demand-related bulk system costs through a coincident peak charge. It may be more appropriate to recover such demand-related costs through a different demand charge, such as billing capacity, which would remain consistent with cost causation principles.</p> <p>As well, the findings with respect to seasonality in the report appear to reflect geographic distinctions, and the AESO is required to offer a postage-stamp tariff.</p> <p>Based on the direction provided in EUB Decision 2005-096, other rate design principles should only be given consideration after the cost causation principle is satisfied.</p> <p>The quantitative analysis in the Preliminary Report examines bulk line loading as reflective of thermal constraints on the bulk system. The AESO agrees that bulk line loading does not necessarily reflect voltage or stability constraints. However, voltage or stability constraints which contribute to maximum stress frequently occur during periods of high loading on bulk lines (combined with poor power factor for voltage constraints). Finding that bulk line loading does not correlate to AIL total system demand indicates that coincident demand may not be an appropriate billing determinant to</p>

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	<p>EPCOR – Support 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.</p> <p>IPCAA – Indifferent 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?</p> <p>Kinder Morgan – Support 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:</p> <ul style="list-style-type: none"> • 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. <p>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.</p> <p>Medicine Hat – Oppose 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</p>	<p>recover bulk system costs driven by thermal constraints, but it does not follow that energy is a more appropriate billing determinant for such costs nor that energy is the appropriate billing determinant for costs driven by voltage or stability constraints.</p> <p>Please see the AESO's response to ATCO Electric comments above.</p> <p>The AESO agrees additional consideration would be required for details such as ratchet provisions.</p> <p>Please see the AESO's response to ATCO Electric comments above.</p> <p>As detailed in the original Transmission Cost Causation Study, other jurisdictions generally have not investigated cost causation for the transmission system in detail.</p> <p>The move to coincident peak billing was based on cost causation principles. If coincident peak billing is not supported</p>

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	<p>reverting to recovery of bulk system costs based on billing capacity.</p> <p>TransAlta – Support TransAlta tentatively supports consideration of billing capacity for recovery of bulk system costs but more evidence is required to support this proposition.</p> <p>TransCanada – Indifferent 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.</p>	<p>by cost causation, the AESO considers it inappropriate to continue it. Although coincident peak billing is already implemented, questions of transparency and stability remain. As well, maintaining a separate billing determinant incurs on-going administrative and billing costs which may otherwise be avoided.</p> <p>Billing capacity, which is still a demand-based billing determinant, was suggested by the AESO as an alternative to coincident peak. The AESO agrees that moving to a billing determinant simply for practicality and convenience does not meet the rate design principles established by Decisions 2005-096.</p>
5. Calculation of Coincident Demand Component		
<p>The original <i>Transmission Cost Causation Study</i> 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</p>	<p>ADC – Position not indicated 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</p>	<p>In the AESO’s opinion, the results of the Preliminary Report suggest that coincident peak billing may be “approximately wrong” rather than “approximately right”, although further investigation is warranted. The Preliminary Report examined bulk system loading as a function of AIL</p>

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<p>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.</p>	<p>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.</p> <p>ATCO Electric – Support 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.</p> <p>EnCana – Position not indicated 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.</p>	<p>peak load in accordance with the terms of reference for the 2006 Cost Causation Study. If the study results do not support a cost causation relationship, what does ADC propose as a cost recovery mechanism? The AESO suggests that operating voltage, voltage drop following a contingency, and stability during a disturbance are constraints which would exhibit an even weaker relationship to AIL peak load or perhaps to customer demand. If that is the case, then recovery on a non-coincident peak basis, or perhaps on an energy basis, may be a more appropriate approach.</p> <p>The AESO considers that the qualitative discussion in section 2 of the Preliminary Report is not “identification by exception”, although the quantitative analysis could be considered that. The AESO does not agree that the analysis “double-counts” demand causation. The minimum system analysis demonstrated that beyond the minimum size required to accommodate the demand on the transmission system, other energy-related factors resulted in additional capacity. The Preliminary Report now adds that, for the minimum size required to accommodate demand on the system, a quantifiable component has a causal relationship to coincidence with AIL peak. The Preliminary Report</p>

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	<p>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.</p> <p>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’.</p> <p>EPCOR – Support EPCOR supports that there should be more costs classified as energy-related, as the revised calculation has provided.</p> <p>IPCAA – Oppose 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.</p> <p>Kinder Morgan – Support</p> <p>Medicine Hat – Support 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.</p> <p>TransAlta – Oppose 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</p>	<p>does not address what the remaining component should be classified as, in part because the causal relationship to coincidence is weak.</p> <p>The AESO agrees that additional examination of the qualitative assessments of bulk system costs drivers may be helpful, and expects to complete such examination for the final report.</p> <p>Please see response to EnCana comments above.</p> <p>The AESO supports rate design based on cost causation and other principles. The nature of Alberta’s transmission system does not lend itself to simple classification such as 100% energy-related or 100% demand-related.</p> <p>Please refer to comments in point (d) of the AESO’s response letter.</p>

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	<p>robust approach to determining coincidence considering rate stability concerns.</p> <p>TransCanada – Oppose 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.</p> <p>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.</p>	<p>The AESO agrees that the costs of a transmission system are largely fixed in nature. However, despite costs being fixed, it remains appropriate that they be recovered based on a variable quantity — either demand or energy — to appropriately allocate costs to users of the system. Where the cost driver for the bulk system is not coincidence with system peak but rather reflects a variety of non-coincident factors, the challenge is to determine the most appropriate cost recovery mechanism.</p> <p>With respect to double-counting, please refer to the response to EnCana’s comments above. The minimum system analysis may have only been used in distribution cost studies because detailed transmission cost studies have not been conducted in other jurisdictions, as discussed in the original Transmission Cost Causation Study.</p>
Additional Comments		
	<p>ADC – 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</p>	

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	<p>common sense and to regress from the progress that we feel was made in the last rate proceeding.</p> <p>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.</p> <p>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.</p> <p>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.</p>	<p>If transmission system costs are driven by “factors over which [load customers] have no control,” then it may not be appropriate to recover those costs using a specific charge which may be neither transparent nor stable. It may be more appropriate to use a billing quantity which the customer can monitor and control and which, in conjunction with other rate components billed on the same quantity, provides a clear and significant price signal.</p> <p>The AESO agrees that collaboration and cooperation before an application is filed should result in improving the efficiency of the regulatory process. The AESO has also responded to data requests from ADC. In the interests of transparency, the AESO has made the responses available to all stakeholders on the AESO’s website, and suggests that discussions with ADC or BAI generally be open to other consultation participants.</p> <p>The AESO would also like to reiterate that its proposal for the 2007 rate design has not been “hardened” as suggested by ADC in comments provided in Item 1 above. The AESO distributed the Preliminary Report and requested comments on the AESO’s views to prompt stakeholder discussion and feedback. The AESO will consider stakeholder comments in finalizing the 2006 Cost Causation Study and in preparing the rate design for its 2007 tariff application.</p>

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	<p>EnCana – 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.</p> <p>Kinder Morgan – Kinder Morgan thanks the AESO for the opportunity of providing early comments on the cost causation study.</p> <p>Red Deer-Lethbridge – 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.</p> <p>TransAlta – 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. [graphs attached to and provided with original stakeholder comments]</p> <p>TransCanada – 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.</p>	<p>The AESO expects to hold a stakeholder meeting after a final discussion paper is issued, or possibly before in response to comments from ADC provided above.</p> <p>The transmission system reference will be clarified to indicate the 240 kV bulk system in the final report. The comments in section 2.2 of the Preliminary Report were a summary of qualitative assessments by transmission system planners. They were not the result of quantitative analysis. The AESO is not sure what the purpose of such analysis would be, given that bulk system costs must be recovered from transmission load customers in accordance with the Transmission Regulation.</p> <p>The AESO suggests the current consultation process, which will include meeting with stakeholders, is an appropriate approach to receive comments on best practices and standard terminology.</p>