

ALBERTA ENERGY AND UTILITIES BOARD

**IN THE MATTER OF THE
ALBERTA ELECTRIC SYSTEM OPERATOR
2007 GENERAL TARIFF APPLICATION
NO. 1485517**

—

**WRITTEN REPLY ARGUMENT
OF THE
ALBERTA ELECTRIC SYSTEM OPERATOR**

JULY 13, 2007



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1 STAKEHOLDER CONSULTATION AND PROCESS MATTERS

Argument was filed with respect to the AESO's 2007 General Tariff Application by 15 parties (besides the AESO): ADC, ASBG/PGA, ATCO Electric, CCA/PICA, DUC, DUC/TCE, EnCana, EPCOR, FortisAlberta, IPCAA, IPPSA, Powerex, PPGA, TCE, and TransAlta.

The AESO provides the following reply Argument to those parties. Where the AESO has already sufficiently addressed matters in its Argument, no further comments are provided. However, lack of response in this Reply Argument to any particular matter raised by interveners in Argument does not indicate agreement on that matter by the AESO.

The AESO has numbered sections in this Reply Argument in accordance with the decision outline distributed by the EUB on May 30, 2007. Where the AESO provides no further comments with respect to a particular section in the outline, that section has simply been omitted from this document.

1.1 Stakeholder Consultation

ASBG/PGA suggest "that a Board sanctioned workshop process, similar to that employed for the recent ATCO Gas Phase II process (Application 1475249), should be considered by the AESO for future GTAs, to ensure a more level playing field amongst interested stakeholders." (ASBG/PGA Argument, page 1) CCA/PICA similarly suggests "a Board sanctioned workshop process...be considered by the AESO for future GTAs" (CCA/PICA Argument, page 2). The use of a technical meeting or information conference is already addressed in EUB Bulletin 2005-31: *Revisions to EUB Cost Policies and Prehearing Processing for Utility Matters*. Bulletin 2005-31 provides appropriate guidance for the use of workshops and similar processes, and the AESO will consider its utility and applicability when preparing future tariff applications. The AESO submits that there is no need for specific additional direction as a result of this proceeding, regarding the use workshops or similar processes in tariff proceedings.

PPGA stated that it was "disappointed to find that the AESO had restricted its discussions regarding the implementation of its Distribution Point of Delivery Interconnection Process Guidelines (Ex. H-002, H-003) to a discussion with distribution companies..." (PPGA Argument, page 5). The AESO noted (1T: 0198, line 15 to 0199, line 9):

In the actual development of these particular guidelines, it primarily again included the distribution companies.

Q *Now, in Section 1.3(a) you are going to – you say you're going to seek input and feedback from affected parties prior to making changes or additions. Would that include under affected parties people beyond the DISCOs?*

I believe we would, yes.

Q *And I noted in 1.1, paragraph 1, the proposals are for a large new customers. Would parties such as the PPGA and the companies it represents fall in that category?*

5 *I believe it would as it states throughout the documents, specifically in Section 2 where it talks about the considerations involved with interconnecting a customer, whether it be on transmission or distribution. So yes, I would say yes.*

10 The AESO notes that it undertakes different types of consultation that engage customers and encourages communication and participation. The AESO engages the necessary parties on a case by case basis, and anticipates participation by interested parties at each stage in the process.

15 The AESO also notes that while the intention of a stakeholder consultation process is consensus, that may not always be the outcome, and the AESO attempts to pursue the most reasonable and fair course of action taking into account all technical and regulatory principles as part of its decision-making process.

20 The AESO notes TransCanada's suggestions regarding consultation and specifically the recommendation "to establish a Rates Committee to review tariff issues (rate design, cost of service, terms and conditions) with the mandate to meet frequently, to provide comments to the AESO, to provide a forum for issues to be reviewed and discussed early in the process, to work the process and to provide feedback to the stakeholders." (TCE Argument, page 1)
25 While the AESO has noted that its tariff consultation process could be improved (4T: 0875, lines 15-23), it does not endorse the "committee" concept put forward by TransCanada. On the one hand TransCanada suggests "sorting out issues on a month-to-month basis" (TCE Argument, page 1), but at the same time TransCanada notes that the experts that could be involved in such a process are expensive.

30 In the AESO's view, rate design is a matter that should be reviewed only at certain (ideally relatively infrequent) intervals, and is not a task that lends itself to continuous review. This would be at odds with the objective of certainty and stability. It certainly does not seem to the AESO that TransCanada's suggested committee approach would enhance efficiency or
35 reduce costs overall.

The AESO agrees with many participants that there is value in consultation which can contribute to a more efficient regulatory review process. Indeed, there are many examples in the 2007 Application which demonstrate that stakeholder feedback was in fact incorporated
40 in the AESO's proposals, resulting in elements of the proposed tariff that were not contentious and were therefore not further examined during the hearing process. For example, stakeholders encouraged the AESO to revert to the traditional approach of determining investment in customer interconnections without a prepaid operations and maintenance component, as discussed in Section 6.5.2 of the Application (Exhibit 007,
45 Section 6, pages 13-15). The AESO accordingly applied to remove the prepaid operations



and maintenance charge which exists in the AESO's current tariff, and no participant in this proceeding has opposed its removal.

5 The AESO provided feedback during the consultation process in a transparent way to the extent possible (Exhibit 004, AESO Application, Section 3, page 2, and as noted throughout Sections 4 and 6 of the Application), but the reality is that there comes a time when the application needs to be filed. While this may mean that opportunities for further feedback no longer exist, and as a result that some parties may not feel they have had the "last word", the EUB will appreciate this reality which the AESO faces in matters concerning its tariff applications.

10
15 The AESO will continue to conduct consultation in advance of filing its tariff applications, in a manner that is designed to contribute to streamlining the review process, wherever reasonably possible. Based on feedback and information gleaned from the 2007 tariff consultation and other consultations conducted by the AESO, the AESO will review and modify the consultation approach in relation to the next occasion of a tariff review. At the same time, lack of consensus or settlement on some matters prior to the regulatory review process should not be considered a failure of the consultation process. This is primarily due to the nature of Phase II matters, where parties often have conflicting interests not just with the AESO but also amongst themselves, as well as the fact that stakeholders engage or commit to the consultation process to varying degrees, given the availability of the EUB regulatory review process.



2 PHASE I MATTERS

2.2 Deferral Accounts

5 ASBG/PGA suggest “a Board sanctioned workshop process would also be applicable to the
review of deferral account filings.” (ASBG/PGA Argument, page 2) The AESO’s comments,
in Section 1 of this Reply Argument with respect to the guidance offered by EUB Bulletin
2005-31: *Revisions to EUB Cost Policies and Prehearing Processing for Utility Matters*, also
10 apply to the use of workshops or similar processes in deferral account proceedings.

10 TransCanada recommends “that the AESO should be directed to submit its Deferral Account
applications in a more timely fashion.” (TCE Argument, page 2) As discussed during the
hearing (3T: 0753, line 12 to 0754, line 16), the AESO is currently finalizing a deferral
account reconciliation application for the years 2004 and 2005, which will also include a
15 second reconciliation for the year 2003.

20 During the process of developing the 2004-2005 deferral account reconciliation application,
the AESO has developed an automated deferral account reconciliation tool. The AESO
expects that this tool will allow earlier filing of deferral account reconciliation applications in
the future.

Given the actions already taken regarding the filing of deferral accounts, the AESO submits
that no specific direction is required from the EUB in this proceeding.

3 PHASE II MATTERS

3.2 Rate Design Principles

5 TransCanada recommends “the adoption of rate design principles derived from those
approved in Board Decision 2000-1” (TCE Argument, page 3). As the AESO explained in
Argument (page 16, lines 32-35), “Principles and the weight which is accorded them change
and evolve over time to reflect changing legislation, policies, circumstances, and conditions.
10 The AESO submits that the more recent statements of principles should be considered the
more appropriate to use in assessing a rate design.”

TransCanada, however, appears to consider a certain version of the principles proposed by
Bonbright as being particularly noteworthy, specifically those referenced by the Public
Utilities Board in a 1985 decision (Decision E85063, referenced in TCE Evidence, page 4,
15 footnote 19). TransCanada apparently would ignore the fact that Bonbright himself does not
agree. In the latest edition of Bonbright’s work referenced in the AESO’s Application,
information responses, and Argument, following a list of ten “attributes of a sound rate
structure”, which are similar in large part to the eight principles cited by TransCanada, the
following comments are provided (*Principles of Public Utility Rates* by Bonbright, Danielsen,
20 and Kamerschen, 2nd ed., 1988, page 384):

*Lists of this nature are useful in reminding the ratemaker of considerations
that might otherwise be neglected, and also useful in suggesting important
reasons why problems of practical rate design do not yield readily to scientific
25 principles of optimum pricing. **But they are unqualified to serve as a base
on which to build these principles** because of their ambiguities (how, for
example, does one define “undue discrimination”?), their overlapping
character, their inconsistencies, and their failure to offer any basis for
establishing priorities in the event of a conflict. For such a basis, **we must
30 start with a simpler and more fundamental classification** of ratemaking
functions and objectives. [emphasis added]*

The “simpler and more fundamental classification” in the pages of Bonbright’s text which
follow this paragraph is that from which the AESO adapted the five rate design principles
35 summarized in section 4.2 of the AESO’s Application (Exhibit 005, section 4, page 4, lines
32-29) and with which the EUB agreed in Decision 2005-096 (pages 14-16).

TransCanada’s views also differ from the AESO’s with respect to how efficient use of the
transmission system should be achieved. TransCanada considers that efficiency is a
40 fundamental principle of rate design and “submits that the efficiency criterion is important
enough that it merits individual identification as a separate rate principle.” (TCE Evidence,
page 6)

The AESO considers efficiency to be an outcome, rather than a principle, of good rate
design. As explained by the AESO in Information Response IPCAA.AESO-006 (b) (Exhibit
45 112), a customer should be charged “a fair, objective, and equitable amount for the service
provided, no matter how the customer uses the service.” The customer is expected to

respond in a manner that would minimize those charges, and the resulting outcome is efficient use of the transmission system.

5 TransCanada suggests the AESO rate needs to explicitly promote efficient usage by sending a price signal that encourages usage at times other than system peak, and states, “If the AESO tariff sends a price signal that encourages those customers to alter their usage of the system to off-peak usage, there is the potential for significant cost savings to all customers.” (TCE Evidence, page 5) The AESO submits, based on its examination of bulk system cost causation in this proceeding, that such a signal would **not** result in efficient usage and significant cost savings, because usage at times other than system peak can contribute to maximum stress on bulk system components as summarized in section 3.4.3.1 of AESO Argument (pages 40-42). In the AESO’s view, the most efficient use of the bulk transmission system would be reflected in “consistent, long-term, and predictable usage patterns” (Exhibit 112, Information Response IPCAA.AESO-006 (b)) resulting from “a clear signal that customers should avoid demand peaks and should strive for as flat a load profile as practical.” (Exhibit 112, Information Response IPCAA.AESO-028)

3.3 Transmission Cost Causation

20 EnCana proposes a very simplified view of cost causation (EnCana Argument, page 8, lines 6-15):

25 *In summary, EnCana submits that the past, present and future transmission planning in Alberta focuses on preparing the transmission system to reliably serve the two most credible conditions forecasted to create the maximum flows across the bulk transmission system. This includes (1) a credible forecast of surplus generation based on a high-generation/ light AIL load (worst-case surplus generation condition) that will determine the need for new transmission to serve generation additions and (2) a credible forecast of the maximum AIL load based on the coincident system peak, coincident regional peaks or near peaks that will determine the need for new transmission to serve load growth (worst-case load condition). Because the system is planned in preparation for these conditions, it is submitted that they appropriately represent the “cause of costs”.*

35 EnCana apparently considers that only “the two most credible conditions forecasted to create the maximum flows” matter. This position is untenable for several reasons.

- 40 • First and foremost, “transmission planning is very complex and is not dominated by any one simple factor such as AIL peak load. Transmission planning is driven by a large number of independent factors such as the location of generation and load, the profiles (daily and seasonally) of generation and load, and the configuration of the electric transmission system in Alberta.” (Exhibit 012, AESO Application, Appendix C: *Transmission Cost Causation Update*, page 13)
- 45 • The conditions evaluated when assessing requirements to upgrade transmission system components are “a function of the load and generation in a region” that are relevant to the components being upgraded, not generation and load conditions on the system as a

whole (Exhibit 012, AESO Application, Appendix C: *Transmission Cost Causation Update*, page 9).

- As noted in the 10-Year Transmission System Plan, 88 different cases were studied because “the time of day and system conditions that stress different sections of the bulk transmission system do not necessarily coincide” (Exhibit 107, page 44).
- Individual projects involve studies of multiple cases as well, such as the 17 conditions studied +1, +5, +10, and +15 years into the future for the Edmonton-Calgary bulk transmission system (Exhibit 121, Information Response PWX.AESO-018).
- Although specific cases will be most relevant for a given bulk transmission system facility, different cases are relevant to different facilities as indicated in the points from interviews with transmission planning personnel included in the Transmission Cost Causation Update (Exhibit 012, AESO Application, Appendix C, pages 11-12).

Clearly, the transmission system is planned based on considerations beyond EnCana’s “two most credible conditions forecasted to create the maximum flows”. In fact, it seems unreasonable to expect that all the complexity and conditions identified above would be appropriately represented solely by the 12 hours of the year when system load is at its monthly peak. As the AESO concluded in its Application, “recovering bulk system costs on a coincident peak basis cannot be justified from a cost causation perspective.” (Exhibit 005, Section 4, page 8, lines 45-46)

EnCana also suggests the AESO’s analysis examines the wrong variables, and in particular that it “fails to account for the system capacity because these studies investigate only the demand for transmission use and ignore the rated capacity of transmission paths.” (EnCana Argument, page 12, lines 11-13) However, a capacity utilization analysis of line loading was provided in Information Response EnCana.AESO-025 (b) (Exhibit 172), and shows that many lines are loaded from 50% to 75% of their rated capacities over the entire day and throughout most of the year. Many of these lines will require upgrading if peak loading on them increases much beyond its current level.

3.3.1 Functionalization of Costs

ASBG/PGA suggest that, with respect to the functionalization of dual-use substation costs, “further effort and resources should be devoted to securing appropriate cost data from the TFOs for the next AESO GTA.” (ASBG/PGA Argument, page 3) However, the securing of additional data will not assist in the functionalization of dual-use substations costs. The *Transmission Cost Causation Update* describes the issue: “Dual use substations will provide a challenge for correlation because some substations were sized to serve the load with little or no regard for generator size, while other substations were sized to accommodate the generator with little or no regard for the load while other substations have DTS and STS load/supply of similar magnitude.” (Exhibit 012, AESO Application, Appendix C, page 50)

The functionalization of dual-use substation costs between supply and load is essentially a matter of policy, and the EUB in Decision 2005-096 determined that an appropriate approach is through the use of substation fractions. The AESO therefore submits that the approach adopted in the *Update*, where “[t]he functionalization of dual use facilities is

completed on the basis of substation fractions...” (Exhibit 012, AESO Application, Appendix C, page 51), is reasonable and appropriate, and would not be improved by the securing of additional data from the TFOs.

5 ASBG/PGA state “that overall summer peaking is not as significant as winter peaking on the system.” (ASBG/PGA Argument, page 4) However, the *Transmission Cost Causation Update* notes that “transmission upgrades in southern Alberta are driven by constraints that occur in summer, and therefore do not coincide with the time of annual AIL peak load.” (Exhibit 012, AESO Application, Appendix C, page 12) Summer peaking is therefore
10 significant for a material part of the transmission system in Alberta, and summer loads can result in upgrades being required for transmission system components.

PPGA recommends “that the AESO move 2% of the POD costs from POD to the local category” in respect of high-side breaker costs (PPGA Argument, page 23). CCA/PICA support this recommendation “to the extent this equipment forms part of the networked, or
15 looped system, which is part of the local system” (CCA/PICA Argument, page 26).

As explained in the *Transmission Cost Causation Study*, doing so would create “misalignment between functionalization and cost treatment in the contribution policy”
20 (Exhibit 012, AESO Application, Appendix C, page 46). High-side breakers are part of the substation facilities to accommodate a new customer and would be considered part of customer-related costs under the AESO’s contribution policy. Since the POD charge includes recovery of customer-related costs, it would be inappropriate to re-functionalize some of those costs as local system. The *Transmission Cost Causation Study* recommends
25 that this “tradeoff” in accuracy be accepted to maintain alignment with the existing customer contribution definitions.

3.4 Demand Transmission Service (DTS) Rate Design

30 3.4.1 Rate Design Considerations

TransCanada considers that “the AESO has failed to meet the significant burden of proof required to justify a major change of this nature” for several reasons (TCE Argument, page 8). The AESO offers the following comments in response to TransCanada’s “reasons”:
35

- (1) *The AESO proposed rate design is contrary to well accepted practices in North America for allocating bulk transmission system costs.*

As explained in AESO Argument (page 23, lines 31-32), “similar detailed analysis has not been conducted in other jurisdictions”. As well, the cost causation study filed by the AESO in its 2005-2006 tariff application and updated in the current proceeding is the first such study completed for the Alberta transmission system, as noted by ADC (ADC Argument, page 2). A rate design based on the detailed analysis of the cost causation study and update should not be faulted for results contrary to
40 practices in other jurisdictions where such studies have not been completed.
45

- (2) *The AESO proposed rate design is contrary to positions adopted by other rate design and cost of service experts in Alberta through history and in the current case.*

5 As noted in point (1) above, the detailed analysis of the cost causation study and update was not available to “rate design and cost of service experts” in historical rate proceedings, so it is not unreasonable that positions they adopted vary from that proposed in the AESO’s Application. With respect to the current rate case, parties have proposed a variety of cost classifications for rate design (as summarized in Section 3.4.3 of this Reply Argument), and contrary positions exist for every proposal put forward in this case.

- (3) *When a change is directionally very different from what is currently in place there ought to be a higher standard of proof.*

15 The AESO considers that appropriate “proof”, including any “higher standard” to the extent the EUB should agree it is necessary, is provided by the extensive and detailed analysis provided in:

- the original *Transmission Cost Causation Study*,
- the *Transmission Cost Causation Update* filed as Appendix C to the AESO’s Application (Exhibit 012), which was completed to specifically address and further refine elements of the study in accordance with EUB directions in Decision 2005-096,
- the additional bulk system analysis filed as Appendix D to the AESO’s Application (Exhibit 013),
- Sections 4.3 and 4.5 of the AESO’s Application (Exhibit 005), and
- Information Responses and other information provided during the course of this proceeding

30 IPCAA similarly suggests a “higher standard of proof” is required (IPCAA Argument, page 2), and the AESO’s comments above equally respond to it.

- (4) *When a change is being proposed on a matter that the Board has recently ruled on, there should be some compelling reason(s) or significant new facts to demonstrate the Board erred in their previous ruling.*

35 The last four items listed in point (3) above represent “compelling reason(s) and significant new facts” which were not available when the EUB approved the AESO rate design in Decision 2005-096. The AESO itself was surprised by this new information, and stated in Argument, “Contrary to the expectation expressed during the AESO’s 2005-2006 GTA hearing, the *Transmission Cost Causation Update* found that there was very weak correlation between individual bulk line loading and total AIL.” (AESO Argument, page 18) The EUB’s earlier decision should not be faulted simply because it was based on the best information available at the time.

- (5) *There are a significant number of interveners who are opposed to the change. In fact, through the course of the proceeding, the only intervener who appears to offer any support for the change is CCA/PICA.*

5 As noted in point (2) above and further discussed in Section 3.4.3 of this Reply Argument, there is no unanimity among interveners on the appropriate DTS rate design. Simply because some parties oppose the AESO's proposal does not mean there is universal support for an alternative.

10 **3.4.1.1 Cost of Service Criterion**

ADC states, "The fact that the load on some isolated lines is inversely correlated to the total provincial load is not that surprising, and in no way diminishes the role of coincidence." (ADC Argument, page 19) This may be a reasonable statement if the inverse correlation was in fact an exceptional circumstance. However, the evidence is clear that fully "28 lines (35%) of the 79 240 kV bulk system lines were negatively correlated with system demand in 2005, and 34 lines (43%) were negatively correlated in 2004." (AESO Argument, page 30, lines 4-6) The *Transmission Cost Causation Update* also included the following observations (Exhibit 012, AESO Application, Appendix C, page 28):

- 20 • "In reviewing the hourly data, none of the 240 kV circuits experienced its annual peak load during the hour of the AIL peak load."
- "Also, none of the 240 kV circuits experienced its monthly peak load during the hour of the monthly AIL peak load."
- 25 • "During the hour of AIL peak load, 240 kV circuits were loaded at about 60% of their annual peak load on average."
- "During the hour of AIL peak load, 5 of 79 lines in 2004 and 4 of 79 lines in 2005 were at 90% or more of their annual peak load."

30 In short, it appears that lack of correlation with total provincial load is not an exception as suggested by ADC, but rather quite common. This lack of correlation with system peak leads to the conclusion that it is inappropriate to recover bulk system costs on a coincident peak basis.

35 EnCana also suggests the AESO's analysis considers situations that are not relevant and that "the most strenuous condition will be the one combination of load, generation and contingency conditions that places the maximum flows (i.e. line loading) on the transmission facilities under examination." (EnCana Argument, page 11, lines 10-13, emphasis in original) The AESO generally agrees, and notes that the single combination of conditions which produced maximum flows on each of the 79 240 kV bulk system lines in the province did **not** occur at the time of monthly system peak. As noted above, "none of the 240 kV circuits experienced its monthly peak load during the hour of the monthly AIL peak load." (Exhibit 012, AESO Application, Appendix C: *Transmission Cost Causation Update*, page 28) Again, this indicates that the recovery of bulk system costs on a coincident peak basis does not reflect when maximum stress occurs on the bulk transmission system.

45

ASBG/PGA suggest “that in applying the cost causation criterion particular attention has to be given to the impact of seasonal DISCO customers since these customers do not utilize the transmission system during the peak winter period.” (ASBG/PGA Argument, page 5) However, the AESO’s analysis of the monthly profiles of loading on each of the seventy-nine 240 kV bulk transmission lines in the AIES reveals that “the bulk transmission system, on average, exhibits no distinct...monthly usage patterns.... In effect, some bulk lines are heavily loaded, and some are lightly loaded, in...every month of the year.” (Exhibit 005, AESO Application, Section 4, page 11, lines 42-46) Therefore, seasonal customers can increase loading on bulk system lines like other customers, and therefore require no special consideration with respect to cost causation.

CCA/PICA recommend that “time of use price signals consistent with cost causation would promote the efficient use of the transmission service.” (CCA/PICA Argument, page 6) Based on analysis by TransCanada, the AESO concluded in Argument, “At most, TransCanada’s analysis suggests that bulk system lines exhibit maximum loading over a broad daytime period, as over 2,000 km of lines experience maximum loading in each hour from about Hour Ending 8 to about Hour Ending 21.” (AESO Argument, page 41, lines 3-5) CCA/PICA also suggests a broad daytime “on peak period of HE8 to HE23 in all days and all months to provide a strong signal that use during any of the on peak hours can result in bulk system cost causation.” (CCA/PICA Argument, page 20) However, cost recovery over broad on-peak periods generally provides limited price differentiation compared to cost recovery over all hours, and therefore is ineffective at providing a price signal that could result in more efficient use of the transmission system.

DUC states “that historical system investments in customer interconnections for large PODs [are] materially different from the current policies of the AESO. The difference stems from the AESO’s current policy of only investing in a single transformer for new customer connections, whereas historically in Alberta more than one transformer was provided for larger services.” (DUC Argument, page 6, line 31 to page 7, line 2) Although DUC provided an example during the hearing of a large load where the AESO’s standard service proposal was apparently based on a single line and a single transformer (6T: 1338, lines 17-22), the AESO suggests the usual practice is described in Exhibit H-032. That information response from the AESO’s 2005-2006 GTA stated, “Three sizes of transformers are generally used for new interconnections to the transmission system, with multiple transformers used to serve larger loads.” The largest expected long term load served through a single transformer on the 138 kV system was stated to be 47 MW, and on the 240 kV system was stated to be 78 MW. The AESO considers this practice to be reasonably consistent with historical practice, and that no change in policy has occurred. At the same time, the AESO recognizes that considerations specific to an individual interconnection could sometimes result in the AESO varying from its usual practice.

In any event, the AESO notes that of the 28 substations for which information was provided as part of the Customer Contribution Study Data in Appendix G to the AESO’s Application (Exhibit 016, “Subs” Tab), seven of the 28 substations, or 25%, included two transformers. For comparison, in the historical data provided as an attachment to the AESO’s information request to DUC AESO.DUC-003 (Exhibit 256), 145 of the total of 451 substations, or 32%, included two or more transformers. This suggests that the AESO’s recent practice is

consistent with historical practice, and multiple transformers continue to be utilized in some services for large loads.

5 TransCanada proposes “that the AESO should be directed to produce revenue to cost ratios for each rate class in subsequent filings.” (TCE Argument, page 13)

10 A review of the rate calculations provided in Section 5 of the AESO’s Application (Exhibit 006) shows that the AESO has only two rate classes to which costs are allocated: Demand Transmission Service (DTS) and Supply Transmission Service (STS). The costs borne by each of these rate classes is established in legislation, as summarized in Section 4.1 of the Application (Exhibit 005, Section 4, pages 3-4). Furthermore, the costs allocated to each of those two rate classes are shown to be fully recovered within each rate class in Schedule 5.10 in Section 5 of the Application (Exhibit 006). Both DTS and STS therefore have revenue to cost ratios of 100%, effectively as required by legislation.

15 All other proposed rates of the AESO — Fort Nelson Demand Transmission Service (FTS), Demand Opportunity Services (DOS), Export Transmission and Opportunity Services (XTS and XOS), Merchant Transmission and Opportunity Services (MTS and MOS), Primary Service Credit (PSC), and Import Opportunity Service (IOS) — are derived based on comparable component charges from the DTS and STS rates. That is, the cost components are not determined and distinct charges developed to recover those costs, but rather the appropriate component charges from the DTS and STS rates are simply included in the additional rates. For example, the comparable component charges for DOS, Export, and Merchant rates are provided in Schedule 5.8 in Section 5 of the AESO’s Application (Exhibit 20 006).

This approach is taken because almost all of the component charges of these additional rates relate to shared or common costs that could not be explicitly determined for the rates.

30 As a result, the AESO only has charges — that is, revenues — for each of the additional rates, and not costs, which means that revenue to cost ratios in effect cannot be calculated. The AESO therefore submits that the production of revenue to cost ratios for the AESO’s rates would not provide useful information on which the AESO’s rates could be examined or assessed.

35 **3.4.1.2 Other Rate Design Criteria**

40 TransCanada begins its discussion of other rate design criteria by stating, “AESO customers fall into two broad categories, Disco PODs serving communities and Disco or direct connect PODs serving large industrial customers.” (TCE Argument, page 14)

45 TransCanada then continues, “Disco PODs serving communities are serving large numbers of residential, general service, small industrial and other customers. It is inconceivable given the diversity and numbers of these customers that they could all determine when the monthly AIS peak occurs and all turn off their use of electricity during that one hour.” (TCE Argument, pages 14-15)

5 The AESO interprets this submission to say that it is ineffective to provide a coincident peak price signal at multi-user DISCO PODs, and notes that such PODs account for over three-quarters of DTS energy and demand in Alberta (Exhibit 106, Information Response EnCana.AESO-002 (a)). The AESO therefore suggests that in such a case it is even more important that charges are “fair, objective, and equitable” as discussed in Section 3.2 of this Reply Argument. The AESO generally agrees that distribution customers served through multi-user DISCO PODs may be limited in their ability to respond to a coincident peak price signal. However, they are generally able to respond to a billing capacity charge which “provides a clear signal that customers should avoid demand peaks and should strive for as flat a load profile as practical” as discussed in Information Response IPCAA.AESO-028 (Exhibit 112).

15 TransCanada also comments that for large industrial loads, “In some months like May where the system load is flatter, it is even harder to predict the system peak hour and so someone load shifting has to do so for a lot of hours.” (TCE Evidence, page 15) The AESO suggests this indicates a coincident peak charge is not appropriate in such months, as selecting a single hour of system peak is meaningless when the system load is flat over “a lot of hours”. A better price signal is provided by a non-coincident peak charge which encourages each customer to avoid demand peaks in any hour and maintain a flat load profile, as discussed above.

20 Moreover, the AESO submits that TransCanada’s suggested division of AESO customers into the two broad categories discussed in the preceding paragraphs is too much of a generalization. Much greater variety of PODs is suggested by the distribution shown in Table 4.5.2, which provides average per-POD DTS bill impacts in Section 4.5.3 of the AESO’s Application (Exhibit 005, Section 4, pages 25-27). For example, smaller load services for backup or standby requirements (as discussed in Section 3.6 of this Reply Argument) are not captured by TransCanada’s two broad categories.

30 In TransCanada’s view, “...the AESO has ignored the very different underlying cost structure prior to January 1, 2006 and after January 1, 2006.” (TCE Argument, page 16) The AESO believes that the underlying cost structure of the transmission system is not “vastly different” than that which existed in 2005. As the AESO explained in Information Response ADC.AESO-003 (t) (Exhibit 094), “The AESO believes that, in the past as today, transmission system expansions were generally required to avoid violation of limits with respect to one or more of thermal capacity, voltage, or stability, and to meet capacity and service location requirements of customers,” and in Information Response TCE.AESO-005 (d) (Exhibit 181), “Transmission planning criteria remain fundamentally the same as in the past.” The AESO submits that while the level of costs recovered from load customer increased in 2006, the structure of those costs remains essentially unchanged from 2005. The AESO’s understanding of cost causation factors relating to those costs has also changed from 2005, resulting in the AESO’s proposal for changes to the DTS rate in this Application.

45 EnCana suggests the AESO’s DTS rate must be designed to “maintain the fidelity of the transmission system price signals as they flow-through to the end-use customers.” (EnCana Argument, page 19, lines 26-27) The AESO disagrees. The DTS rate design should reflect

5 cost considerations and rate design principles appropriate to a transmission system. For
example, most end-use customers do not have interval meters, and the AESO's DTS
Operating Reserve Charge (which varies hourly as a percentage of pool price) therefore
cannot be accurately flowed through to them. However, it would be inappropriate to
constrain the design of the Operating Reserve Charge solely due to this factor. The AESO
10 submits it remains appropriate that "the distribution utilities will make decisions as to how to
best manage their costs of transmission service, including setting rates for their customers
that give consideration to what signals their customers can respond to in order to contribute
to minimizing transmission costs" as stated in Information Response EnCana.AESO-002
(b-d) (Exhibit 106).

3.4.1.3 Ratchets and Contract Demands

15 ADC states that "contract demand is not the appropriate measure of demand because it
would imply that there is absolutely no diversity involved in the planning or design of the bulk
transmission system, i.e. that planners could not take advantage of the fact that not all
customers peak at the same time." (ADC Argument, page 14) ADC's statement may have
merit if the AESO proposed to recover bulk system costs solely on contract demand.
20 However, this is not the case.

First, the AESO proposes that bulk system costs be recovered in part through a demand
(\$/MW) charge and in part through a usage (\$/MWh) charge, as discussed in Information
Response EnCana.AESO-015 (Exhibit 106). Second, the AESO proposes that those costs
recovered through a demand charge be recovered on billing capacity, which is determined
25 as "the greatest of the highest metered demand in the billing period, 90% of contract
capacity, or 90% of the peak demand in the prior 24 months." (Exhibit 005, AESO
Application, Section 4, page 12, lines 29-31) The AESO considers that the contribution of
contract capacity as one factor in the determination of billing capacity, and the recovery of
only approximately half of bulk system costs through a billing capacity charge, appropriately
30 reflects the consideration of contract capacity in the planning and design of the bulk
transmission system "to the extent that the bulk system is planned to meet future loads on
the system as indicated in part by customers' contracted capacity" (Exhibit 005, AESO
Application, Section 4, page 12, lines 21-22).

35 ASBG/PGA has a similar concern but with respect to demand ratchets — specifically, that a
demand ratchet "provides a billing determinant for transmission service for all of the months
that a seasonal service is not connected to the downstream distribution system."
(ASBG/PGA Argument, page 6) As discussed above, the AESO again submits that when
costs are recovered in part through a demand (\$/MW) charge and in part through a usage
40 (\$/MWh) charge, and when that demand charge is based on a billing determinant which
reflects actual metered demand, contract capacity, and ratchet provisions, then the resulting
annual charges to seasonal services are appropriate and reasonable.

3.4.3 Classification of Costs

3.4.3.1 Bulk System

5 Participants in the AESO's 2007 GTA have proposed a variety of cost classifications on which to base the recovery of bulk system costs in the DTS rate design. The AESO provides a summary of those approaches in Table 3.4.3 below.

10 *Table 3.4.3: Bulk System Cost Classifications Recommended by AESO 2007 GTA Participants*

Participant	Billing Capacity (\$/MW)	Coincident Peak (\$/MW)	On-Peak Ratcheted NCP (\$/MW)	All Hours Usage (\$/MWh)	On-Peak Usage (\$/MWh)
ADC		82%			18%
AESO	51.4%			48.6%	
ASBG/PGA		51.4%		48.6%	
CCA/PICA			51.4%	48.6%	
DUC		82%		18%	
DUC/TCE (Standby)				100%	
EnCana Recommended		58.8%		41.2%	
EnCana Alternative				41.2%	58.8%
IPCAA		82%		18%	
Powerex		100%			
TransCanada (2007)		82%		18%	
TransCanada (future)				18%	82%

Sources:

- Exhibit 221, Direct Testimony of Alan Rosenberg, page 20, lines 9-10
- Exhibit 004, AESO Application, Section 4, page 16, lines 44-45
- ASBG/PGA Argument, page 10
- CCA/PICA Argument, pages 14 and 20
- DUC Argument, page 12
- DUC/TCE Argument, for uncontracted energy (all energy consumed above contract capacity), page 3, lines 1-4
- EnCana Argument, page 23, lines 9-10, page 20, lines 4-6, and page 26, lines 27-29
- IPCAA Argument, pages 3 and 9
- Powerex Argument, page 23
- Exhibit 242, TransCanada Evidence, page 32, lines 16-26
- ATCO Electric, EPCOR, FortisAlberta, IPPSA, PPGA, and TransAlta did not specifically provide recommendations for the classification of bulk transmission system costs.



5 Despite most parties' suggestions that a particular classification is clearly superior to others, there is little agreement between parties. The AESO notes that most parties representing large industrial customers (ADC, DUC, IPCAA, and TCE) prefer continuing to classify 82% of bulk system costs on a coincident peak basis, at least for the current application. Beyond that, however, there is significant variation in parties' recommendations.

10 The AESO suggests this indicates the complexity of the issues being addressed with respect to recovery of bulk system costs. The AESO recommends, as have other parties, that all factors be considered as thoroughly as possible. The AESO has provided its assessment of all related factors in its Application and other information filed in this proceeding, and continues to believe that its proposed cost classification represents a balanced approach to bulk system costs recovery.

15 ADC characterizes the AESO's proposed bulk system cost classification as a "headlong determination to largely reverse the prior Decision." (ADC Argument, page 3) IPCAA similarly states that "the AESO appears to have simply tried to resurrect these two proposals by using different (but no more valid) reasoning than it used last time." (IPCAA Argument, page 4) These assertions are in defiance of the extensive and detailed analysis completed by the AESO to respond to directions in Decision 2005-096 and in preparing its Application, as well as the information shared in the consultation conducted prior to filing the Application.

20 The AESO had no "determination to largely reverse the prior Decision", and instead noted, "Contrary to the expectation expressed [by the AESO] during the AESO's 2005-2006 GTA hearing, the *Transmission Cost Causation Update* found that there was very weak correlation between individual bulk line loading and total AIL." (Exhibit 005, AESO Application, Section 4, page 8, lines 24-26) In fact, the AESO concluded that recovering bulk system costs on a coincident peak basis cannot be justified from a cost causation basis only in the face of the compelling evidence summarized in its Application.

30 ADC also suggests the AESO has "one, **and only one**, pretext for diverging so far from its own transmission cost causation study – the stated desire to use the Average and Excess Demand methodology." (ADC Argument, page 12, emphasis in original) ADC is again either mischaracterizing or ignoring information presented in the AESO's application. The AESO summarized the process of developing its proposed rate design in the Application as follows.

35 (1) First, the AESO concluded after extensive and detailed analysis that "recovering bulk system costs on a coincident peak basis cannot be justified from a cost causation perspective" (Exhibit 005, AESO Application, Section 4, pages 8-11).

40 (2) Then, the AESO determined that "billing capacity also is an appropriate billing determinant for the recovery of bulk system costs." (Exhibit 005, AESO Application, Section 4, pages 11-12)

45 (3) Further investigation led the AESO to conclude that "the demand-related classification of the bulk system should be reduced to account for varying POD load factors and varying probabilities that individual POD loads will coincide with

maximum stress on transmission system components.” (Exhibit 005, AESO Application, Section 4, pages 15-16)

5 (4) Different cost classification options were considered as discussed in Information Response BR.AESO-002 (Exhibit 080)

10 (5) Finally, the AESO concluded the average and excess demand methodology addressed issues identified in its investigation and best satisfied the rate design principle of fairness, objectivity, and equity, and therefore recommended that approach as the basis for its proposed rate design (Exhibit 005, AESO Application, Section 4, pages 16-17, and further discussed in Information Response IPCAA.AESO-003 (a) (Exhibit 112)).

15 The average and excess demand methodology was a solution to providing a rate design that satisfied the principles laid out in Section 4.2 of the AESO’s Application (Exhibit 005, Section 4, pages 4-5), not a methodology that the AESO simply “desired” to use as suggested by ADC.

20 EnCana provides the following recommendation (EnCana Argument, page 22, line 16 to page 23, line 6):

25 EnCana recommends that the Board retain the existing proportion of bulk wires costs that are classified as energy-related at 41.2%. This is reasonable on the grounds that a meaningful portion of bulk system costs are caused by the addition of generation to the system. Since the Board cannot allocate bulk wires costs directly to generation customers, it is submitted that a second best approach is to allocate such costs to load customers in proportion to their likelihood of using generation services. EnCana submits that the probability of using generation is directly proportional to the energy consumption of the load customer. In addition, a 41.2% classification incorporates the findings of the original *Transmission Cost Causation Study* (“TCCS”) which indicated that approximately 19% of bulk system costs are energy related.

35 The AESO submits that the rationale of classifying wires costs as energy-related to reflect a causal relationship to generation was thoroughly canvassed and rejected by the EUB in the AESO’s 2005-2006 tariff proceeding, as summarized in Decision 2005-096 (pages 26-29). The requirement that the transmission system accommodate generation customers has not changed since that proceeding. The suggestion that “the probability of using generation is directly proportional to the energy consumption of the load customer” is illogical: it is a certainty that generation will be used whenever energy is consumed by load, but the question of where that generation will be located (and therefore which transmission lines will be loaded) depends on multiple factors including pool price and dispatch order. Finally, recommending a 41.2% energy-related classification to “incorporate” a 19% energy-related classification is without basis. The AESO submits that EnCana’s rationale should be rejected.

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5 TransCanada comments, “The standard Average and Excess method would assign 80% of costs to energy and is therefore inefficient and a poor match with the fixed cost nature of bulk transmission assets.” (TCE Argument, page 19) The AESO agrees with TransCanada’s conclusion, but not because of any inherent “inefficiency” of the average and excess demand (AED) methodology. Rather, the AESO suggests that classifying 80% of costs as usage-related would be appropriate *only if the average load factor was 80% for the facilities for which costs are being classified*. Since the average load factor of the bulk transmission system lines is 51.4% (Exhibit 005, AESO Application, Section 4, page 16, lines 38-42), that is the appropriate load factor to use to determine the demand- and usage-related components under an AED methodology. Use of the system load factor is inappropriate because transmission line loads are not comparable to system load, as shown by the AESO’s analysis in this Application and in particular the load duration curves for 240 kV lines in the additional analysis of bulk system data provided as Appendix D to the AESO’s Application (Exhibit 013, page 17, and corrected for 2004 in the AESO’s Errata Filing No. 2, Exhibit 382, pages 5-6).

20 ADC states that, under the average and excess demand methodology, excess costs must be allocated using “excess demand, that is the demand exceeding the average demand” (ADC Argument, page 12). As the AESO stated during the hearing, the methodology is used for “allocating costs to rate classes”, and with only one rate class it does not matter how excess costs are allocated because the entirety of excess costs are allocated to the same single rate class (1T: 0304, lines 8-15).

25 TransCanada suggests the AESO’s comment that it “didn’t really worry about what method we would use to allocate those excess costs to rate classes because the single rate class got them all anyway” (TCE Argument, page 20) indicates that the AESO was unconcerned about the load factor used to establish the average and excess components. As discussed above, the AESO considers the average load factor of the bulk transmission system to be appropriate, and that determination establishes the **excess** costs for the DTS rate class. Regardless of whether those excess costs are calculated based on peak, average, coincident, or non-coincident demand, all of the excess costs are borne by the DTS rate class. The AESO also agrees that if demand-related costs are charged to individual PODs based on an AED methodology, then the specific AED variation used becomes important. However, the AESO understands — and considers it reasonable — that costs are typically only classified, not billed, using an AED methodology, and therefore does not propose to bill costs using an AED methodology. The AESO instead recommends a continuation of the approach used to bill demand-related costs in Alberta prior to 2006 — namely, on a billing capacity basis incorporating non-coincident peak, ratchet, and contract capacity components.

40 ADC states that, for the AESO in this proceeding, rate design is not different than cost allocation (ADC Argument, page 4). ADC considers that “rate design for the DTS tariff is an exercise in cost causation among the members of the DTS class.” (ADC Argument, page 13) ADC considers the steps of cost allocation and rate design to be “a distinction without a difference” (ADC Argument, page 13) when there is a single rate class.

5 The AESO disagrees. Cost allocation is an attribution of costs to the service provided to a class or group of customers that are differentiated based on distinct usage or cost patterns, as discussed in Information Response TCE.AESO-028 (a-b) (Exhibit 126). Costs are allocated to a rate class as precisely as possible, and then rates are designed *for the class* to provide a revenue-to-cost ratio at or near unity. Rate design, however, determines the individual amounts charged to individual customers within a rate class, and is a process whereby costs are “appropriately averaged to reflect that customers are paying for system access service” (AESO Argument, page 62, lines 39-40). It is generally accepted that, through the averaging process of rate design, the revenue-to-cost ratio for an individual service would rarely, if ever, be near unity (assuming the specific costs for a particular 10 service could be determined, which is questionable in its own right). ADC essentially argues that the AESO need only perform cost allocation at the individual customer level and rate design becomes unnecessary, while the AESO’s approach is that rate design be performed for the rate class which makes cost allocation unnecessary. The AESO considers that the latter approach — determining a rate design for the rate class — more appropriately satisfies the rate design principles identified in Section 4.2 of the AESO’s Application (Exhibit 005, Section 4, pages 4-5). 15

20 TransCanada comments that “the metered demand for every hour of every Point of Delivery is measured by the AESO. Therefore, the coincidence of each Point of Delivery with the peak system load is known.” (TCE Argument, page 21) TransCanada’s statement is true but irrelevant, since the AESO’s evidence shows “that recovering bulk system costs on a coincident peak basis cannot be justified from a cost causation perspective” (Exhibit 005, AESO Application, Section 4, page 11, lines 32-33). As discussed in Information Response 25 EnCana.AESO-012 (b) (Exhibit 106), what “cannot be measured or prophesied directly” in any practical manner is the extent of load coincidence of each POD and each of the various components of the transmission system. It is therefore appropriate to use the stochastic or probabilistic approach of the AED methodology.

30 Based on questioning of the AESO panel, TransCanada concluded the AESO’s “approach to cost studies is that they will change every time the planners change the way they plan the system.” (TCE Argument, page 27) The AESO’s evidence was in fact that past causes of costs would not be ignored, but that “a better approach to system planning [that] more accurately reflects and predicts the cost drivers on the system” would be utilized to perform 35 a cost causation study.” (2T: 0473, lines 19-25) TransCanada’s approach would apparently be to ignore “a better approach...that more accurately reflects and predicts the cost drivers on the system” and instead rely on a previous approach that presumably *less accurately* reflects and predicts the cost drivers. If TransCanada’s approach had been followed in Alberta, costs would likely still be classified today based on the 1 CP methodology that was 40 place prior to the mid-1980s, as discussed in Information Response TCE.AESO-009 (d) (Exhibit 126).

45 CCA/PICA suggest that “since load flow increases on some of the bulk system components are positively correlated with load, it would be appropriate to recover the cost of a portion of bulk system costs on the basis of a suitable demand cost recovery method. The remainder of the bulk system costs should then be considered as required for the delivery of energy and appropriately recovered using an energy cost recovery method.” (CCA/PICA Argument,

5 page 10) CCA/PICA's conclusion misinterprets the transmission line loading information. If loading on a transmission line is negatively correlated with system load, it indicates that a POD peak which is not coincident with system peak may still be coincident with peak load on the transmission line. It does not indicate that peak loading is unimportant and costs should therefore be recovered on a usage (\$/MWh) basis. Rather, it indicates that peak loading may be important in every hour, which is the conclusion reached by the AESO in its Application (Exhibit 005, Section 4, page 11, line 46).

10 CCA/PICA go on to recommend that "the AESO be directed to consider a classification to demand having regard to the bulk system line length for which load flow is positively correlated with load using modeling assumptions used by transmission planners for planning the transmission system, including recognition of contingencies." (CCA/PICA Argument, page 10) For the reasons just provided, the AESO submits that it would be incomplete to consider only the bulk system lines which are positively correlated with system load. The
15 AESO has already explained in Argument "that its line loading analysis does take into account contingency conditions to the extent that they actually affect loading on the transmission system." (AESO Argument, page 30, lines 13-15)

20 3.4.4 Allocation of Costs

3.4.4.1 Bulk Wires Allocation

25 TransCanada suggests the AESO's conclusion to recover demand-related bulk system costs using billing capacity was based on limited analysis of the bulk transmission system. In reality, the AESO examined multiple aspects of the bulk transmission system in extensive detail as summarized in the *Transmission Cost Causation Update* (Exhibit 012) and in Appendix D to the AESO's Application (Exhibit 013), including:

- 30 • interviews with system planners to determine when maximum stress occurs on transmission paths and its relationship to the time of peak AIL (*Update*, pages 9-13);
- correlation between 240 kV line loading and AIL in 2005 and 2004 (*Update*, pages 13-22);
- correlation between 240 kV line loading as percent of thermal capacity and AIL in 2005 and 2004 (*Update*, pages 23-25);
- 35 • actual flows on the north-south path between Edmonton and Calgary in 2005 and 2004 (*Update*, pages 26-27);
- forecast flows on the same path for 2007 (*Update*, pages 27-28);
- loading on 240 kV transmission lines in the hours of monthly and annual system peaks in 2005 and 2004 (*Update*, page 28);
- 40 • loading on 240 kV transmission lines during the days on which monthly system peaks occurred in 2005 and 2004 (Appendix D, pages 3-14);
- average hourly and average monthly loading on 240 kV transmission lines in 2005 and 2004 (Appendix D, pages 15-16); and
- 45 • load duration curves for 240 kV transmission lines in 2005 and 2004 (Appendix D, page 17).

As discussed in Section 4.3.2 of the AESO's Application (Exhibit 005, Section 4, pages 8-12), after completing this extensive and detailed analysis the AESO concluded that "recovering bulk system costs on a coincident peak basis cannot be justified from a cost causation perspective" (page 11, lines 32-33) and that "recovery of demand-related bulk system costs on billing capacity is the most appropriate approach." (page 11, lines 39-40)

TransCanada suggests a high correlation between system peak load and planning area peak loads is important (TCE Argument, pages 32-33). The correlation should not be surprising, since planning area loads represent the sum of DTS loads in each planning area, while system load represents the sum of DTS loads in the province. TransCanada presents no information on the correlation of 240 kV line loading to planning area loads, and instead simply assumes that "if planning areas are peaking at about the same time as the system is peaking, the flows on the transmission lines are also peaking." (TCE Argument, page 33) However, the AESO's analysis showed that 240 kV line loading does not peak when the system load peaks. If there is correlation between area peaks and system peaks, it would also be reasonable to expect that 240 kV line loading does not peak when the area load peaks. TransCanada's analysis is therefore not particularly helpful.

TransCanada reiterates its views on "the limitations on the accuracy of...the cost of service study..." (TCE Argument, page 35). TransCanada instead suggests that ignoring the *Transmission Cost Causation Study and Update* is a better alternative, even though the EUB recognized the *Study* as "a good first step" in Decision 2005-096 (page 24) and even though the *Update* responded to the EUB's directions in that Decision and built upon the original *Study*.

EnCana suggests that if the EUB approves continuation of a 12 CP billing methodology, then it should "direct the AESO to use of the AIL [Alberta Internal Load] data as the monthly measure of 'system peak' instead of the sum of all POD metered values, as currently used by the AESO." (EnCana Argument, page 26, lines 17-19) The AESO cautions that a meter used "for the purpose of obtaining the basis of a charge for electricity" must be verified or calibrated in accordance with Section 9 of the *Electricity and Gas Inspection Act* (R.S. 1985, c. E-4), and meters used to determine AIL do not meet those requirements. The AESO submits that using the sum of all POD metered values does satisfy legislated requirements for revenue metering, and therefore remains appropriate if coincident peak billing is continued in Alberta.

EnCana further suggests that "using AIL avoids an inherent administrative complexity associated with the sum of POD metered values because the summed-up 'system peak' must be recalculated every time any one POD value is adjusted due to a billing error; this results in a re-billing for all customers, not just the one." (EnCana Argument, page 26, lines 21-24) EnCana apparently misunderstands the AESO's comment that "we have the occasional problem of metered data restatement, which causes the coincident peak to move, meaning that bills had to be reissued for every customer because that coincident peak time is now different." (2T: 0485, lines 10-15) A metered data restatement (or "billing error", in EnCana's term) does not cause re-billing of all customers unless it causes the **time** of coincident peak to change. A change to the level of the "summed-up" system peak has no impact on other customer's bills, as the bill simply reflects each customer's individual

demand at the time of system peak. Metered data restatements which affect the time of system peak are less common than ones which affect the level of system peak.

3.4.4.2 Local Wires Allocation

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With respect to recovery of local system charges, ADC suggests, “With a ratchet, the customer has a weak incentive to reduce its demand once it has already set the ratchet because there will be no attendant rate relief until the ratchet is gone.” (ADC Argument, page 20) The AESO submits that a ratchet provides a strong incentive for a customer to avoid demand peaks in the first place, as each peak could establish a charge which would continue for the duration of the ratchet period or extend beyond an existing ratchet period, as discussed in Information Response EnCana.AESO-018 (b) Revised (Exhibit 188). The resulting charges could significantly exceed those attributable to a non-ratcheted demand, and therefore would provide a stronger, not weaker, incentive “to control load, avoid demand peaks, and strive for as flat a load profile as practical” (Exhibit 188).

3.4.5 Point of Delivery (POD) Charge

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DUC proposes that “the interconnection cost function above 40 MW should be \$30,000/MW or less, in particular, should the AESO continue with its policy of only allowing one transformer to be classified as standard facilities.” (DUC Argument, page 19, lines 5-7) The AESO addressed DUC’s comment on the “policy of only allowing one transformer” earlier in Section 3.4.1.1 of this Reply Argument. In its Argument, the AESO acknowledged “there is some merit in the suggestion by DUC that directionally, the average costs for larger PODs may be lower than that represented by the AESO’s proposed Raw Cost Function.” (AESO Argument, page 75, lines 25-27) Based on information presented in this proceeding and relied upon for other components of the POD cost function, the AESO proposed a final cost function segment above 50 MW of \$47,000/MW. Based on the reasons provided in its Argument (pages 75-78), the AESO continues to recommend the revised raw project cost function as reasonably representing the costs associated with both small and large interconnections, namely:

$$\begin{aligned}
 \text{Point of Delivery Costs} &= \$0.947 \text{ million} \\
 &+ (\$0.621 \text{ million/MW} \times \text{first 7.5 MW of DTS Capacity}) \\
 &+ (\$0.154 \text{ million/MW} \times \text{next 42.5 MW of DTS Capacity}) \\
 &+ (\$0.047 \text{ million/MW} \times \text{DTS Capacity above 50 MW})
 \end{aligned}$$

3.6 Standby Rate Proposal

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IPCAA states that with respect to standby customers, “their demands on the transmission system are sporadic and random” (IPCAA Argument, pages 9-10). DUC/TCE similarly maintain in their evidence that for standby loads, “Higher demand periods tend to be random and unpredictable” (DUC/TCE Argument, page 5, line 15) and that such loads therefore should be attributed lower costs than more predictable loads. The AESO disagrees. As discussed in Information Response IPCAA.AESO-006 (b) (Exhibit 112), “the AESO considers that consistent, long-term, and predictable usage patterns contribute to enabling the efficient development of the bulk and local systems.” Standby loads are challenging to

appropriately plan for, as demonstrated by the extensive work and multiple approaches summarized in the *Fort McMurray Area Service Requirements Forecast* provided as an Appendix to the AESO's Rebuttal Evidence (Exhibit 348). The AESO submits there is no evidence to suggest standby loads should be attributed the minimal amount of bulk system costs suggested by IPCAA and DUC/TCE.

DUC/TCE also present Figures 5 and 10 in their Argument (DUC/TCE Argument, pages 7-8) as evidence that standby loads impose minimal load on the transmission system. Although the AESO agrees that any hour averaged over all 365 days of the year results in the low aggregate load calculated by DUC/DCE, the peak aggregate load in an individual hour is significantly higher. For example, the AESO's response to IPCAA.AESO-047 (c) Revised (Exhibit 219) shows that the maximum coincident hourly loads at 64 substations also serving STS customers was 554 MW in 2005 and 486 MW in 2004, while the sum of non-coincident loads at those substations (which the AESO agreed would be representative of total backup load on the system) was 1,139 MW in 2005 and 1,000 MW in 2004. In other words, the maximum coincident hourly loads arising from backup service would be 48.6% ($554 \text{ MW} \div 1,139 \text{ MW}$) of connected backup load in 2005, and 48.6% ($486 \text{ MW} \div 1,000 \text{ MW}$) of connected backup load in 2004. Although averages over all days may be low, the actual peak coincident backup load imposed on the transmission system is much higher, and comparable to the 38% of charges for "normal" service which the AESO proposes is attributable to backup or standby service (AESO Argument, page 51, lines 1-3).

IPCAA and DUC/TCE both refer to a segregated analysis of the load data at the 64 substations discussed above. In the DUC/TCE *Results From Analysis of AESO Confidential Data* (Exhibit H-021), the loads are segregated into:

- 19 "backup only" loads, with load factors generally less than 10%;
- 52 "standby" loads, with load factors generally in the range of 30% to 50%;
- 12 "load" loads, with load factors generally higher than 60%; and
- 3 "other" loads, where there was insufficient data to complete an analysis.

The 19 low load factor "backup only" loads are first offered as evidence that such loads do not cause costs on the transmission system (IPCAA Argument, page 11). Yet the *Results From Analysis* shows that the maximum coincident demand of these "backup only" loads was about 14% (Exhibit H-021, page 4, Figure 3) while the average demand was about 0.8% (Exhibit H-021, page 4, line 5). This appears to the AESO to be a rather large degree of coincidence for loads that are "sporadic" and "random".

The 52 medium load factor "standby" loads are then segmented into low load factor and high load factor portions, and the low load factor portions are also offered as evidence that such loads do not cause transmission system costs (IPCAA Argument, page 11-12). The high load factor (also referred to as "normal" or "base" load) portions of these "standby loads" had maximum coincident demand of about 58% (Exhibit H-021, page 9, Figure 8), while the low load factor portions had maximum coincident demand of about 14% (Exhibit H-021, page 9, Figure 8) compared to an average demand of about 2.8% (Exhibit H-021, page 8, line 16). Again, this appears to the AESO to be a rather large degree of coincidence for the "standby" portion of these loads.

The 12 “load” and 3 “other” loads were not analyzed in the same manner in the *Results From Analysis* (Exhibit H-021).

5 The AESO suggests it is not surprising that when you analyze only low load factor loads, or
when you extract and analyze only the low load factor portions of medium load factor loads,
that you get low average coincident demand. The AESO notes, however, that either way the
maximum coincident demand significantly exceed the average coincident demand, by a
factor of 17 for the “backup only” loads and a factor of 5 for the “standby loads”. This
10 suggests a relatively high degree of coincidence for these loads regardless of how they are
analyzed.

15 The AESO also suggests that the more appropriate way to analyze the loads is in their
entirety, rather than separating some deemed standby portion from the remaining “normal”
portion. Information Response IPCAA.AESO-047 (c) Revised (Exhibit 219), as discussed
earlier in this section, provides analysis based on a “whole load” approach. It considers the
entirety of the loads at these substations to conclude that the maximum coincident hourly
loads arising from backup service would be 48.6% of connected backup load, in both 2005
and 2006. The AESO considered that segregating and segmenting the lowest load factor
portions for separate analysis is inappropriate. This could arguably be done for all loads on
20 the system and, if it was, would simple shift costs between customers.

25 DUC/TCE also continue to maintain that their “proposed standby rate will provide a revenue
to cost ratio slightly above unity, even assuming backup loads were to be attributed 39% of
the costs of normal loads.” (DUC/TCE Argument, page 11, lines 5-7) This position is
nonsensical. If standby loads would pay the same charges under the DUC/TCE proposal as
under the AESO’s proposal (which also has a “revenue to cost ratio” slightly above unity),
the DUC/TCE would not be arguing so strongly for a separate rate proposal. The AESO
submits that a more accurate comparison is provided in its Argument, which shows that for
30 the example used by DUC/TCE, “the annual charge under the DUC/TCE proposed standby
rate is approximately half the annual charge under the AESO’s proposed DTS rate” (AESO
Argument, page 53, lines 22-24). The difference arises because the AESO’s comparison
reflects annual charges in which standby load occurs only one month of the year, whereas
DUC/TCE’s calculation effectively assumes standby load occurs in every month of the year.
35 The AESO considers that if standby load occurs every month of the year, then it is more
similar to a “normal” service than a backup or standby service, and should accordingly pay
an even higher share of costs.

40 DUC/TCE state, “Dual-use customers provide distinctive benefits to the AIES” (DUC/TCE
Argument, page 12, line 24). IPPSA similarly states, “Decentralized generation is good for
the transmission system and should be encouraged through the AESO’s rate design.”
(IPPSA Argument, page 3) However, the benefits (generation near load, voltage support,
VAR generation capability, system reliability, and transmission cost deferral (DUC/TCE
Argument, page 12, line 31 to page 13, line 8, and IPPSA Argument, page 3)) arise due to
45 the existence of generation, not due to the existence of load. The AESO suggests the
allocation of minimal costs to generation customers in the AESO’s tariff and in accordance
with the *Transmission Regulation* (as discussed in Section 4.1 of the AESO’s Application

(Exhibit 005, Section 4, page 4, lines 9-14)) already recognize the benefits of generation on the transmission system, and no further recognition is required for the **load** services at dual-use sites.

5 IPPSA states that it is inappropriate to bill bulk transmission system charges for backup or
standby loads “when the system hasn’t been used for the last 23 months or less” (referring
to ratchet charges) or “whether the generator uses the system at all” (referring to contract
demand charges) (IPPSA Argument, page 4). But that is precisely the point. Capacity in the
bulk transmission system is being planned and built to accommodate backup and standby
10 load, as exemplified by the *Fort McMurray Area Service Requirements Forecast* provided as
an Appendix to the AESO’s Rebuttal Evidence (Exhibit 348). The capacity exists whether
backup and standby loads utilize it in any specific month, and it is appropriate to charge
those customers for that capacity through the DTS rate proposed by the AESO “which
balances facilities costs attributed to backup services and risk mitigation.” (Exhibit 005,
15 AESO Application, Section 4, page 38, line 47 to page 39, line 1)

DUC/TCE state “that the AESO’s claim that the proposed standby rate could cause
additional operational difficulties is unfounded as the standby rate is proposed by the DUC
and TransCanada and should be ignored.” (DUC/TCE Argument, page 16, lines 19-21) The
20 AESO, in the context of its responsibility for the safe, reliable, and economic planning and
operation of the Alberta Interconnected Electric System (AIES), stated in its Application,
“Although (as already noted) the current DTS rate allows unscheduled usage, the ratchet
provisions of the rate generally encourage customers to minimize backup service
requirements. Drastically reducing the charges attributable to backup service use would be
25 expected to encourage unscheduled loading and result in increased risks for system
operations and reliability.” (Exhibit 005, Section 4, page 34, lines 19-23) The AESO
suggests that, as operator of the system, its concerns regarding “increased risks for system
operations and reliability” quite simply should not be ignored.

30 DUC/TCE also suggest that increases in standby load “should be viewed as positive as
additional cogeneration will provide additional benefits to the transmission system.”
(DUC/TCE Argument, page 17, lines 9-11) For support, DUC/TCE cites the AESO’s
statement in its 10-Year Transmission System Plan that “Additional system enhancements
will likely be required if these upgraders do not build on-site generation.” (Exhibit 170,
35 page 96) The AESO submits that this is exactly the point of the AESO’s backup service
proposal: if the on-site generation is built, the load services appear as backup services and
would be charged about 38% of the costs attributed to a “normal” service. However, if the
on-site generation is not built, the load services appear as “normal” services and would be
charged 100% of the costs attributed to a “normal” service. As the discussion of the
40 Northeast Alberta Transmission Development regional planning analysis summarized in the
AESO’s Argument (page 48, lines 6-24) demonstrates, there is significant transmission
capacity being planned for that area to accommodate the expected backup loads. Even
more capacity would be required if it were to serve “normal” rather than backup loads. The
AESO submits that no additional discount, beyond that already embedded in the AESO’s
45 proposed DTS rate, is required to appropriately charge and recover costs from standby
loads.

5 With respect to the POD charge applicable to backup or standby loads, DUC/TCE state,
"For customers that had their Contract Capacity set based on interconnection cost recovery,
the DUC and TransCanada submit that a contract buydown will need to be performed as
outlined in Article 9 of the AESO's Terms and Conditions of Service. Switching from the DTS
rate to the proposed standby rate should not normally result in any stranded interconnection
costs." (DUC/TCE Argument, page 18, lines 7-11) For the point of delivery interconnection
facilities, this simply is not true as summarized in the AESO's Argument (page 55, line 28 to
page 56, line 37). DUC/TCE effectively propose that a standby customer who is currently
10 paying a POD charge based on billing capacity (which is the greatest of highest metered
demand, ratchet level, or 90% of contract capacity) be allowed to reduce contract capacity
(with perhaps an additional capital contribution) and then be charged based only on contract
capacity. As a result the POD-related revenue received by the AESO would materially
decrease, although the same POD facilities would remain in place solely for the purpose of
15 serving that customer. In such a case it is clear that POD-related costs are being transferred
from the standby customer to other customers, even though the POD facilities serve only the
backup customer. As stated in Argument, the AESO submits that standby customers should
remain "subject to POD charges based on their peak metered demand or ratchet if they
actually peak above their new contract demand (which standby users would do)." (AESO
Argument, page 56, lines 19-20)

3.7 Demand Opportunity Service (DOS) Rates

25 TransCanada suggests, "The AESO proposes to eliminate the DOS – 1 Hour rate." (TCE
Argument, page 45) The AESO has discussed this issue with TransCanada, and
TransCanada agrees the AESO has not proposed the elimination of DOS 1 Hour in its 2007
Application. The AESO understands that TransCanada will be withdrawing its comments
regarding elimination of the DOS 1 Hour rate in its reply argument.

3.9 Import / Export Rates

3.9.1 XTS Rate

35 The AESO notes that several parties have opposed the approval of the AESO's proposed
Export Transmission Service (XTS) rate in this proceeding, including IPPSA (IPPSA
Argument, page 7), Powerex (Powerex Argument, page 26), TransAlta (TransAlta
Argument, page 3), and TransCanada (TCE Argument, page 50). At the same time, no party
has supported the AESO's proposal or offered alternative proposals at this time.

40 The inclusion of a firm export rate in the AESO's Application responded in large part to
interest in such a service from some of these same stakeholders, as well to encouragement
from the EUB "towards the potential development of firm import and export rates" (Decision
2005-096, page 33). The AESO considers its proposed XTS rate to be reasonable and cost-
based. As well, although not available in every hour, "At least 100 MW of Available Transfer
Capacity (ATC) was available on the Alberta-BC inter-tie for about 80% of the time in the
45 last quarter of 2006," as discussed in Information Response TCE.AESO-055 (a) (Exhibit
126). Based on the comments by participants in this proceeding, however, the AESO
acknowledges that those participants seem unlikely to utilize the proposed XTS rate. It

appears, therefore, that eliminating this rate from the 2007 proposed tariff would have little impact in practical terms. Notwithstanding, participants in this proceeding may not represent all potential users of the service.

5 The participants who opposed the proposed XTS rate noted the lack of continuous export capacity as a consideration in their opposition. The AESO and participants have been aware of this constraint throughout the AESO's consultation on export rates. The AESO would accordingly expect to consult with stakeholders on modifications to the firm export rate, if required, when continuous availability of export capacity becomes more likely, but notes that
10 the timing of such availability will depend on multiple factors. As that timing is unknown, the AESO suggests specific direction at this time regarding the development of a firm export tariff (if the proposed one is not approved as part of this proceeding) would be premature.

15 The AESO also notes that elimination of the proposed XTS rate would not preclude the need for an OASIS (Open Access Same-time Information System) or similar system discussed in Section 4.8 of the AESO's Application (Exhibit 005, Section 4, pages 44-45). The AESO continues to believe that "The OASIS or similar system is required to manage the contracting and scheduling of capacity, allocation of ATC, release of unscheduled capacity, and curtailment of multiple export services on existing inter-ties and merchant
20 interconnections to other jurisdictions." (Exhibit 005, AESO Application, Section 4, page 45, lines 4-6) Even without the XTS rate, the approval of XOS 1 Hour and XOS 1 Month rates constitutes the multiple export services which would require the implementation of an OASIS or similar system. If not approved as part of this proceeding, the AESO would also expect a firm export rate to be approved in a future application, and implementing an OASIS or
25 similar system as a result of this proceeding would allow that rate as well as other potential export rates to be readily accommodated when brought forward in the future.

3.9.2 Export Opportunity Service Rates

30 As TransCanada points out, "In large measure, the difference between the TransCanada proposals, AESO proposals and the status quo comes down to the treatment of what wires-related costs are charged to opportunity service rates and how the operating reserves should be calculated for these opportunity services." (TCE Argument, page 52)
35 TransCanada apparently misunderstands the requirement that operating reserves be carried for all export services.

TransCanada states, with respect to the AESO's operating reserve requirements, "These operating reserves are required even if not 1 MW of export opportunity service is being used." (TCE Argument, page 53) As the AESO explained in Undertaking No. 2 (Exhibit H-022), "the reserve requirement would range from about 450 MW at a load responsibility of about 6,500 MW to about 650 MW at a load responsibility of about 9,500 MW." A load responsibility of 6,500 MW is generally representative of recent minimum levels for the hourly Alberta Internal Load (AIL). Every MW increment above this level requires an additional increment of operating reserves, so generally any load responsibility above 6,500
45 MW results in an incremental operating reserve requirement.

As the AESO further explained in Undertaking No. 3 (Exhibit H-022):

Alberta's firm load responsibility is defined as:

- the AIES firm load demand served under demand transmission service (DTS)
- plus Alberta Interconnected Electric System (AIES) losses
- plus firm export transactions
- minus firm import transactions
- minus firm load under the ISO's DTS which is under contract to provide operating reserves.

All export transactions are required to be firm transactions....

Therefore, every MW of export service will generally increase the load responsibility above 6,500 MW, similar to every MW of DTS above 6,500 MW. Every MW of export service will therefore result in an incremental operating reserve requirement, similar to every MW of DTS above 6,500 MW. Export services should accordingly be charged for operating reserves on the same basis as DTS.

TransCanada states that "operating reserves are not required incrementally until export loads exceed several hundred MWs." (TCE Argument, page 55) TransCanada is simply mistaken in this statement, as explained above. TransCanada's understanding may have been true in the past, when minimum levels for the hourly AIL were lower (for example, 5,500 MW would have been generally representative of minimum levels of AIL in 2002) and the operating reserve requirements were set by Alberta's single largest generator contingency, as discussed in Undertaking No. 2 (Exhibit H-022) However, this is seldom the case in recent years, as Alberta load growth has resulting in the contingency reserve requirements being the sum of 5% of Alberta's firm load responsibility served by hydro and wind generation and 7% of Alberta's firm load responsibility served by thermal generation. Every incremental MW of firm load responsibility, whether from export transactions or DTS, therefore requires incremental operating reserves.

3.11 Primary Service Credit

PPGA proposes a credit it considers to be similar to the Primary Service Credit: a credit for small services interconnected at 138 kV rather than 69 kV.

The AESO explained the benefits of standardizing the transmission system on 138 kV as a minimum voltage in Information Response PPGA.AESO-009 (Exhibit 176). The AESO does not consider that smaller PODs are penalized through the transition to a 138 kV minimum voltage. Significant cost savings are attributable to implementing a 138 kV voltage, arising primarily from not having to rebuild 69 kV lines to accommodate additional load in the future. The additional costs incurred when 69 kV facilities need to be upgraded to 138 kV outweigh the possible cost reductions attributable to less expensive 69 kV facilities. All customers benefit from these cost savings.

As well, although the 138 kV standardization will apply to new projects, consideration will be given to a 69 kV interconnection if 69 kV facilities currently exist in the area and adequate capacity is available.

- 5 The AESO therefore submits that PPGA's proposal of credits for small PODs interconnecting at 138 kV be denied.

3.11.1 Credit Methodology

10 TransCanada "agrees with DUC that, at a minimum, the PSC should be set at 55% of the POD charges, not the 40% proposed by the AESO." (TCE Argument, page 57) The AESO, in Argument, also agreed that the DUC approach to determining the PSC level was superior to that initially proposed by the AESO, and recommended that it be adopted in this proceeding (AESO Argument, page 62, lines 26-28).

15 However, TransCanada goes on to state, "Regarding radial lines, if a customer wholly owns its own substation and it does not have a radial line, it clearly gets no benefit from radial lines and should not be required to cross-subsidize those customers who do receive the benefit of a radial line." (TCE Argument, page 58) TransCanada is in effect arguing that a customer's rate should be based on the **actual** facilities used to supply that customer. The AESO's more conventional view of a rate is that it is "appropriately averaged to reflect that customers are paying for system access service, not for facilities." (AESO Argument, page 20 62, lines 39-40) This view is consistent with the EUB's comment in Decision 2005-096 that the PSC "should be related to the avoided **average** cost of system investment" (page 38, 25 emphasis added).

DUC's analysis, with which TransCanada agrees and which is based on data from the AESO's Customer Contribution Study (Exhibit 014), shows that if 55% of interconnection costs are substation-related, then 45% of interconnection costs are *not* substation-related. 30 The balance of the POD charge, after the recommended 55% reduction for the PSC, simply reflects non-substation-related costs (primarily related to radial lines) averaged over all customers. It is therefore appropriate that a customer receiving the Primary Service Credit continue to pay 45% of the POD charge.

35 TransCanada suggests that service provided to a customer who owns its own substation is comparable to export and merchant services which are attributed no POD costs (TCE Argument, pages 57-58). However, export and merchant services differ from DTS services in that "there are no 'customer-related' facilities associated with export [or merchant] service." (Exhibit 005, AESO Application, Section 4, page 46, lines 36-37) The 40 interconnection facilities for export and merchant services are located in other jurisdictions, and there are no substations, radial lines, or any other customer-related facilities (whether owned by a TFO or by a customer) for those services in Alberta. As a result, the non-substation-related costs associated with export and merchant facilities are 0%, whereas non-substation-related costs associated with domestic interconnection facilities are 45% of 45 the POD costs.



5 TransCanada then reproduces (TCE Argument, pages 59-60) two figures from its Information Response AESO.TCE-24 (Exhibit 334). These figures suggest that customer ownership of a substation should reduce the rate for POD charges from about 86 to about 5 (units unknown). This in turn implies that the substation accounts for about 94% $((85 - 5) \div 86)$ of the customer-related costs of an interconnection, rather than the 55% determined by DUC and with which TransCanada agrees.

10 The AESO also notes that the current Primary Service Credit includes an investment test that “involves an estimate of TFO cost for transformation facilities which it will not supply.” (Exhibit 005, AESO Application, Section 4, page 52, line 35) This investment test, as stated in the AESO’s current PSC, requires that “costs (for the least cost system to interconnect the load at the employed voltage level, including transformation assets and local facilities owned by the TFO) would have been less than the maximum local investment under the AESO’s Customer Contribution Policy”. Since services sometimes fail this investment test, it is clear
15 that a service where the customer owns the substation can sometimes significantly exceed the average cost of load services, presumably due to large amounts of radial line and non-substation-related facilities involved in the interconnection. Providing a Primary Service Credit that reduces the POD charge by 94%, as recommended by TransCanada, would clearly be inappropriate in such a case.
20

4 TERMS AND CONDITIONS OF SERVICE

4.1 Customer Contribution Policy

5 A number of interveners provided comments regarding the AESO's proposed Raw
Interconnection Project Cost Function (ADC Argument, page 21; CCA/PICA Argument,
pages 21-27; DUC Argument, pages 13-21; and PPGA Argument, pages 8-22). The AESO
continues to support the consideration of all components of the tariff, including a customer
10 contribution policy, monthly rates, and termination and buy-down provisions, to ensure tariff
treatment over time is equitable and stable. The AESO submits that both the POD charge
and the AESO investment function should reflect the same POD costs. The use of a similar
foundation for determining a cost function is consistent with the directions provided by the
EUB in Decision 2005-096, and specifically as follows:

15 *To conclude, with regard to the rate design principles discussed above, the
Board considers that cost causation must be afforded the most weight in
attempting to balance these sometimes competing principles when evaluating
a proposed rate design. That is, in reviewing a proposed rate design, the
Board finds that it is critical that the rate design proposed ensures that a
20 customer that causes a cost must be prepared to pay that cost. (page 17)*

25 *The Board has noted in the previous section on rate design principles that it
considers cost causation to be the most important principle and the Board is
in agreement with ADC and IPCAA that rates should reflect this principle to
the greatest extent possible. (page 27)*

*...the Board has determined that cost, not revenue, is the appropriate starting
point for establishing the investment policy. (page 56)*

30 The AESO therefore disagrees with suggestions made by PPGA (PPGA Argument,
page 16):

35 *The AESO has also proposed a linking of the investment and POD functions.
The PPGA agrees that, at first glance, linking the investment function to the
POD charge appears to be a rational approach, until the details are properly
understood.*

40 *As stated by the PPGA, the POD charge and the investment function are very
different. The investment function deals with forward looking decisions, while
the POD charge is an allocation of the historical net book cost of radial lines
and substations to all PODs.*

45 The AESO also disagrees with a similar suggestion from CCA/PICA (CCA/PICA Argument,
page 23):

*CCA/PICA submit there is no relationship between length of radial line and
size of POD. Therefore, it would be appropriate to consider the cost related to*

radial lines separately from the costs related to substations in developing the POD cost function and investment function.

5 PPGA and CCA/PICA both recommend that the basis for determining the POD charge be different from that for determining the investment function. The AESO suggests such an approach is misguided and inconsistent with the EUB directions noted above.

10 CCA/PICA suggest that the AESO proposed POD cost function “should only reflect recovery of line costs for those PODs with radial lines; **not looped lines**, to avoid a double counting of these costs “ (CCA/PICA Argument, page 22, emphasis in original). CCA/PICA propose an alternative POD cost function to address what they consider a “double counting” of costs.

15 The AESO continues to support the determination of a POD cost function which incorporates both radial line costs and substation costs. The mechanism for recovering costs related to providing system access service through a transmission system should be a POD charge that reflects the costs of providing this service as opposed to the costs related to the actual physical facilities. The AESO noted this in its opening statement during the hearing (1T: 0091-0092):

20 *It is therefore especially important when considering the POD component of the tariff to keep in mind that despite the fact that service is provided through physical facilities or pieces of equipment, that the pricing in the tariff is for system access service and is therefore appropriately averaged.*

25 *Customers are not buying facilities or equipment. Rather, they are receiving a service that varies little as facilities are changed or added to the physical system or as other customers increase or decrease their usage.*

30 The AESO further submits that Section 30(3)(a) of the *Electric Utilities Act* requires that the DTS rate does not differentiate on the basis of location, including a locational differentiation that reflects interconnection to radial rather than looped facilities, as follows:

(3) *The rates set out in the tariff*

35 (a) *shall not be different for owners of electric distribution systems, customers who are industrial systems or a person who has made an arrangement under section 101(2) as a result of the location of those systems or persons on the transmission system...*

40 The AESO maintains that the recovery of POD costs through a uniform POD charge is appropriate for all PODs. Ultimately, a number of items will determine project costs, including substation costs, radial line costs, costs of enhancing communications at adjacent substations, seasonal labour costs, and other variables, all of which pertain at the time of interconnection. As the system evolves, what constitutes POD-related facilities may change
45 (AESO Argument, page 32, lines 18-31), but the functionality of the service remains the

same. The Raw Interconnection Project Cost Function should reflect the average cost of all interconnection projects, and should not be segregated into those projects that have radial transmission lines and those that do not.

5 In Decision 2005-096 (page 38) the EUB stated that the “DTS rate is a postage stamp rate which seeks to collect, on an average basis, the total cost of system investment to provide service to all customers. What a customer has expended to acquire its own assets or what the system would have to spend to supply equivalent service could vary widely from customer to customer and from the system postage stamp average”.

10 The PPGA submit that the DTS rate as proposed by the AESO represented a fundamental change, and that “if fundamental or dramatic changes are proposed, they must be supported by a solid and robust analysis” (PPGA Argument, page 7). While the AESO has addressed the allegation of “bad” data and analysis extensively in its Argument, the AESO submits that the proposed changes to the rates do not, in fact, represent a fundamental change, and in reality these proposals are the direct result of the EUB’s directions in Decision 2005-096 (page 29):

20 *As a summary of the above findings the AESO, in its refiling, is directed to amend its DTS rate design as follows:*

- *20% of all wires costs will be collected on an all hours energy basis*
- *Levy a customer-related POD charge, as suggested in the TCCS*
- *Levy a demand charge on bulk wires utilizing a 12 CP allocator*
- *Levy a demand charge on local and POD related costs utilizing an NCP allocator*

30 The PPGA did not participate in the proceeding that led to Decision 2005-096 and the EUB’s direction to implement a POD charge (PPGA Argument, page 8). The PPGA suggests, “It must be understood that the study underlying the development of the POD charge was not subject to a material amount of scrutiny during the 2005/2006 GTA proceedings, as no party expected the Board to take the action it did in its Decision” (PPGA Argument, page 9). The AESO maintains that the implementation of a POD charge is neither unfair nor inequitable, but is simply a measure levied by the Board that is intended to address the principle of cost causation.

40 The PPGA also assert “that if the data provided is inadequate and a large disproportionate difference in rates between rate classes simply cannot be justified, then stable and predictable rates should be established” (PPGA Argument, age 17). However, the AESO has not proposed a difference in rates between classes. In fact, the AESO has not even proposed different rate classes. The AESO submits that this assertion reflects a lack of knowledge and understanding of the AESO’s proposals by PPGA, and should be disregarded by the Board.

DUC noted that “POD charges, the PSC, and all maximum investment levels should be aligned. DUC supports this alignment even though it will mean a substantial reduction in the primary service credits paid to dual-use customers...” (6T: 1282, lines 3-8).

5 Although DUC supports the AESO’s methodology of determining the maximum investment levels from the interconnection cost function, DUC proposed an additional breakpoint at 40 MW to reflect the economies of scale of larger PODs. ADC also supports a multi-segment linear function (ADC Argument, page 21).

10 In its Argument (pages 75-78), the AESO proposed to modify the cost function to incorporate a separate cost segment for loads above 50 MW. With this modification, the AESO submits that its proposed cost function and the associated DTS POD charge and contribution policy are reflective of costs over the full range of load capacities and should be approved.

15 DUC suggests that the inflation index used as part of the AESO’s *Customer Contribution Study* “should be increased by 5% to reflect the higher costs that the TFOs will experience during the time the 2007 tariff is in effect” (DUC Argument, page 25). The AESO reiterates (Exhibit 015, AESO Application, Appendix F: *Customer Contribution Study*, page 11) that
20 the use of the Alberta Consumer Price Index is appropriate and reliable, and notes that for the years 2006 and 2007, the AESO utilized an inflation rate as accepted by the Board in EUB Decision 2006-004 regarding the ATCO Gas 2005-2007 General Rate Application – Phase I. The AESO further contends that the 5% increase does not appear to be based on any trending analysis or inflationary economic reporting. The inflation rates used in the
25 *Customer Contribution Study* should therefore remain as filed.

TCE also proposes that the terms and conditions be modified to include an inflation “adder” for the investment function. The AESO agrees that the application of a project inflation factor
30 “could be one mechanism if there was an appropriate index that could be used” (2T: 0502, lines 13-15). The AESO presented in Argument (pages 75-76):

35 *While a maximum investment function is a forward-looking mechanism (investment is based on new PODs and increased capacities), the rate mechanism seeks to recover revenue requirements from all existing PODs, and therefore the AESO undertook to investigate project capacity ranges such that all existing POD customers were represented in the cost function.*

The policy in place should provide an appropriate price signal such that decisions made today reflect today’s economic position. A contribution policy is not relevant to conditions
40 under which a party interconnected in the past. The AESO submits that a forward looking policy is not a “static” policy. A contribution policy should be revisited as more data becomes available and maintaining the 80/20 criterion will be a useful metric going forward. Where it becomes apparent that this criterion is not being met, the AESO will endeavour to consider additional project information (if available) and project cost inflation when re-visiting the
45 contribution policy (AESO Argument, pages 81-82).

4.2 Standard Facility Issues

4.2.1 ATCO Electric Issue

5 In response to an EUB information request, ATCO Electric proposed that “certain additional language be inserted into the AESO Terms and Conditions in order to clarify the definition of ‘AESO Standard Facilities’ and Article 9.13 ‘Limitations’” (Exhibit 292, BR.AE-003, emphasis added):

10 *“AESO Standard Facilities” mean the least-cost interconnection facilities which meet good transmission **and distribution** practice including applicable reliability, protection, **losses, maintenance practices**, operating criteria and standards, and generally consist of a single radial transmission circuit and a single transformer to supply an individual Point of Connection.”*

15 *Add to Article 9.13 “Limitations”*

20 *(d) **Determine costs to be AESO Standard Facilities in certain circumstances that might, under strict application of the foregoing, have been classified as being in excess of AESO Standard Facilities.***

The AESO does not take issue with the proposed revisions, if so directed by the Board.

4.2.2 PPGA Issue (T vs. D, Required Use of VFDs)

4.2.2.1 Voltage Flicker

The PPGA have requested the following (PPGA Argument, page 27)

30 *With respect to the T versus D debate, the PPGA is simply seeking to have the AESO interpret and apply its existing guidelines and terms and conditions in a manner which would ensure that a customer has a reasonable opportunity to start its motors under various operating conditions. Surely, this is not an unreasonable request and the PPGA submits that the Board should*
35 *direct the AESO to make the necessary changes to its terms and conditions so that its minimum level of service provided through its “standard facilities” achieves this result.*

40 The AESO has provided comment on this issue in both its Rebuttal Evidence (Exhibit 347, pages 11-15) and Argument (pages 81-82). The AESO further notes that it maintains a clear policy in regard to flicker limits for the transmission system, as contained in the AESO’s “Generation and Load Interconnection Standard”, which clearly specifies the applicable standard to be used for this assessment. This is an industry standard and is further adopted by the Canadian Standards Association in the standard CAN/CSA-C61000.

5 The flicker limits on the distribution system are set by the Distribution Facilities Owners (DFOs) and not the AESO. The DFOs have based their flicker limits on standard IEEE 519 or CAN/CSA-C61000. These flicker limit standards have been in place for some time, and have not changed in recent years. To direct either the AESO or DFOs to follow any other methodology would be contrary to good industry practice (AESO Rebuttal Evidence, page 15).

10 With regard to the AESO's obligation to provide a standard level of service, it should be noted that the "standard facilities" designated by the AESO are used to assist with investment policy decisions on customer contribution levels, and does not restrict the customer in selecting a transmission or distribution option. This selection is left completely up to the customer who is in the best position to assess the level of service that is required. Therefore, the AESO maintains that a customer has the inherent right to choose an interconnection alternative to meet that customer's needs, and the current flicker limit standards are fair to all customers that make application for interconnection.

4.4 Staged Contracts and Payments of Related Contributions

20 EPCOR has suggested that "there are cases in the Alberta electric industry where staged contribution payments can more precisely match the timing expenditures. Staged contributions will provide a sharper and more precise economic signal" (EPCOR Argument, page 2). TCE proposed that "if the Board were to disagree that contributions should be made in installments, TransCanada submits that contributions should be placed in an account (incurring interest) and drawn down as the project proceeds" (TCE Argument, page 64).

25 The AESO has previously noted in Information Responses EPCOR.AESO-001 (d) (Exhibit 110) and TCE.AESO-064 (Exhibit 126) that the collection of all customer contributions are consistent with historical practices that date back to the GRIDCO and EAL tariffs. Additionally, Section 29(3)(e) of the recent *Transmission Regulation* (AR 86/2007) requires that the contribution be paid before commencement of construction of the local interconnection facility.

30 The AESO also notes that as part of Decision 2005-096, the Board indicated that "no interest shall be payable by the AESO to a generator owner on any refund amounts" (EUB Decision 2005-096, page 73). The AESO submits that this stipulation would fairly apply to both generator system contributions as well as customer contributions determined for load facilities.

4.7 Payments in Lieu of Notice

40 ADC suggests that "one partial remedy would be to have the exit fee payments (over a five-year period) be based upon the tariff rate that existed at the time of the contract demand reduction (ADC Argument, page 22). The AESO maintains, as presented in its Argument, that the principles supporting the notice provision are not intended to solely address stranded costs, but are also intended to provide a meaningful customer signal for system planning purposes.

5 DUC assert that “in order to uphold the primary cost causation rate design criteria, any Payment in Lieu of Notice charge should be cost based” (DUC Argument, page 26), and second, “to ensure that the Payment in Lieu of Notice charge is not excessive...the period over which the Payment in Lieu of Notice charge should be applied should be reduced to two years” (DUC Argument, page 27). DUC also noted that costs incurred by low and high load factor customers should be differentiated, and that “DTS rate components that are designed to collect bulk and local costs be used.” (DUC Argument, page 27)

10 The AESO submits that even low load factor customers impact system development, are eligible for the same investment formula as other customers, and should therefore be subject to the same provisions as other customers. The two-year period proposed by DUC appears to be an arbitrary number with no basis, whereas, as noted above, the five-year period is not a penalty but is rather a signal for planning purposes and a fair mechanism for system cost recovery (on average).

15 CCA/PICA have indicated support for the AESO’s position “to the extent the system is planned to take into consideration the contribution of a particular load to system peak capacity requirements, it is appropriate for the load to be held responsible for paying the corresponding costs. Since capacity is planned over a relatively long planning horizon, it is also appropriate for the term of the PILON payment to correspond to the planning horizon” (CCA/PICA Argument, page 38).

20 CCA/PICA also introduced the concept of a capacity swap “among customers wishing to exit the system or reduce contract demands to the extent such swaps can be arranged without additional system related costs” (CCA/PICA Argument, page 38). The AESO disagrees with this concept as it embodies the notion of acquired capacity rights, which is inconsistent with the policy and regulatory framework in Alberta. Additionally, the administrative issues related to monitoring such a mechanism may prove extremely burdensome.

30 **4.8 Regulated Generating Unit Connection Charge Matters**

35 Pertaining to EPCOR’s Argument concerning Regulated Generating Unit Connection Charge (RGUCC) matters, the AESO has already provided in evidence the complete rationale for both its proposal to discontinue charging RGUCC upon shutdown of a regulated generating unit prior to the end of its base year life, and its proposal to charge a new generator on a “brownfield” site the full cost of interconnection, be that for new or “re-used” interconnection facilities (Exhibit 007, AESO Application, pages 37-38; Exhibit 110, EPCOR.AESO-002; and AESO Argument, pages 94-96).

40 There are, however, some aspects of EPCOR’s Argument in this regard that are disingenuous and require correction. Specifically, EPCOR misrepresents that the AESO never suggested to EPCOR that the RGUCC payments should persist to the end of the base-year life of the regulated generating unit (EPCOR Argument, page 3, paragraph 8) and that the AESO changed its mind over time with no apparent justification (EPCOR Argument, pages 3-4, paragraphs 12-17).

5 The facts of the matter are that when EPCOR first advised the AESO that the Cloverbar
generating unit would be terminating its service, the AESO advised EPCOR that outstanding
RGUCC charges would apply to the end of the base year life for the unit. Upon receiving
suggestions from EPCOR that this was not appropriate, the AESO undertook to review
whether there were alternative treatments that would be more appropriate in consideration
of the intent behind RGUCC and legislation. Consequently, the AESO determined it would
not be appropriate to continue to recover the payments when the unit had ceased operating,
as explained in the Application (Exhibit 007, Section 6, page 37), and advised EPCOR of
this, whereupon EPCOR at the time indicated to the AESO they agreed. The AESO
10 incorporated this clarification in its proposed Terms and Conditions of Service, and also
attempted to address any other circumstances that it contemplated might arise in this regard
that were previously unforeseen.

15 EPCOR extracts a small part of the transcript in its Argument (that the AESO could “go
either way” (2T: 0374, line 10)), and places it in the context of the AESO proposal to apply
RCN to re-used facilities. However, the full quote (2T: 0372, line 19 to 0374, line) repeated
below, is in respect of whether to charge out the RGUCC to the end of the base year life or
not, when a generating unit terminates before that date, as summarized above.

20 *So our interpretation, which I think we made relatively clear in the application,
was just that, an interpretation of the original decisions behind the RGUCC.*

25 *And, you know, we did have some discussions internally as to whether it was
intended that the full allocated – the deemed allocated amount was intended
to be recovered over time or whether in fact it was more important to look at
the intent of that charge called “the RGUCC.”*

30 *And we thought it was actually quite reasonable that we looked more at the
intent and the affect that it was supposed to have on leveling the playing field
for the generators competing in the market.*

35 *And if you focus on that, it would lead you to conclude that if a generator is no
longer generating and operating in the competitive market, then the charge is
no longer relevant.*

40 *And underlying that is that it was not intended to recover the costs, the
deemed interconnection costs per se, that it was really an element to assist in
making the competitive market work.*

45 *So as you know, I’m sure, we took this interpretation. The only time we
actually had to think about this was with the retirement of Clover Bar, which
happened earlier than the base year life.*

*And we initially were going to charge the remaining RGUCC to the end of the
base year life, even though Clover Bar terminated prior to that, and we
reconsidered for the reasons I just stated, and those being that we didn’t think*

they were particularly relevant because the unit had stopped operating in the market.

5 *So the effect of that is admittedly that the total amount collected through the RGUCC over the fullness of time will be a little bit less than what was deemed to be allocated in the initial decision.*

10 *And, again, admittedly you could interpret it either way. We thought it was reasonable to interpret it the way we did, but I wouldn't be too disappointed if somebody told me that we should have interpreted it in a different way. I – you know, you really could go either way, in my opinion.*

15 When EPCOR again approached the AESO at a later date with its proposal to build a new plant on the brown-field site, the AESO similarly discussed the interconnection provisions and pricing thereof with EPCOR in order to ensure fairness and consistency with the intent of the tariff and legislation. The result of those discussions and fulsome analysis (which was shared with EPCOR) is that the cost of all of the interconnection facilities should apply to the new generator, instead of continuing with the RGUCC charges that would have applied to the old regulated generator previously located on the site. This is what has been reflected in
20 the subsequent update to the proposed Article 14 as provided in the AESO's Errata No. 1 (Exhibit 197).