

Preamble: The AESO states:

Also in Decision 2005-096, the EUB found that the remaining two principles should be given secondary consideration. That is, considerations of stability and of practicality should only cause deviation from cost-based rates in respect of unusual regulatory events, dramatic changes in cost structure, or where cost causation provides limited guidance in evaluating a rate proposal.

Reference: Section 4 – 2007 Rate Design, Page 5 of 53.

Request:

- (a) Please provide an analysis of the Wires Only – Cost Causation Study January 25, 2005 (Exhibit 02-012-010 in 2006 GTA) and the 2006 Transmission Cost Causation Update September 15, 2006 (Appendix C) that identifies all of the instances where expert judgment was exercised in the study or where information was missing or incomplete that could contribute to inaccuracy in the assignment or allocation of costs to the various functions and classes. Include explanations and references in the analysis.
- (b) Please explain the differences between the Cost Causation study/Cost Causation Update in (a) above and a fully allocated cost of service study. Please explain if the AESO considers its cost causation study to be based on normal cost of service study practices or whether this study is unique to the AESO?
- (c) Please confirm that, in general, the less accurate a cost causation study, the less weight that should be placed on that study in designing rates. If not confirmed, please fully explain.
- (d) If the response to (b) identifies differences between a cost causation study and a fully allocated cost of service study, please confirm that, in general, the less accurate a fully allocated cost of service study, the less weight that should be placed on that study in designing rates. If no, please fully explain.
- (e) Please identify the different kinds of cost of service studies, such as embedded versus marginal cost studies, that can be conducted on regulated assets and their corresponding strengths and weaknesses. Also comment on the basis for the choice of cost study undertaken by the AESO and state clearly what type of cost of service study was conducted.

Response:

Revisions to part (e) indicated in italics.

- (a) Studies included in previous GTAs were subject to review during those proceedings. Please refer to the *2006 Transmission Cost Causation Update* (provided as Appendix C to the AESO's 2007 GTA filed on November 3, 2006) for a discussion of methodology and assumptions.
- (b) The original *Transmission Cost Causation Study* (TCCS) was a cost of service study in essence. Given that there is only one rate class responsible for the costs of the transmission system, the TCCS did not include the final step of cost of service studies in identifying revenue to cost ratios by rate class. The *2006 Transmission Cost Causation Update* is a study that addresses issues raised during the AESO's 2005-2006 GTA proceeding. The TCCS used methods consistent with cost of service studies.
- (c-d) In general, confirmed. Where a study is demonstrated to be inaccurate, such inaccuracy should be considered when determining what weight to accord the study.
- (e) Please refer to Bonbright and other authors and publications for a description of the types of cost of service studies possible, and their corresponding strengths and weaknesses.

The type of study conducted for the AESO's 2006 GTA and updated for the AESO's 2007 GTA was a fully-distributed embedded cost study. The purpose of the original study for the AESO's 2006 GTA was to respond to directions in EUB Decision 2001-32 "to determine the appropriate classification of...transmission costs to demand and energy" and to assist with rate design. Fully-distributed embedded cost studies have traditionally been used for that purpose in Alberta. The 2006 Transmission Cost Causation Update was itself not a cost study, but further refined areas of the original study in response to directions in EUB Decision 2005-096 and identified by the AESO and stakeholders.

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...In any event, the Update concluded the impact on total cost functionalization and classification would be expected to be small because OMA costs account for about one-quarter of TFO revenue requirements, all equipment involves a similar mix of vintages, and the largest cost function (bulk system) contains relatively equal amounts of line and substation equipment.

Reference: Section 2 – 2007 Rate Design, Page 12 of 53.

Request:

- (a) Please provide the evidence supporting the statement that the bulk system contains relatively equal amounts of line and substation equipment.
- (b) Please provide a complete analysis, including supporting schedules, to support the statement that about one-quarter of TFO revenues requirements are OMA costs. Also, identify which of those OMA costs are fixed in nature (unaffected by short-term variation in energy consumption on the transmission system) compared to OMA costs, if any, that do vary with energy consumption.

Response:

Revisions to part (a) indicated in italics.

- (a) *Please refer to Table 6 on page 55 of the 2006 Transmission Cost Causation Update filed as Appendix C to the AESO's 2007 GTA on November 3, 2006. The breakdown of AltaLink and ATCO Electric TFO facilities in that table shows that the bulk system function is comprised 43.6% of substations, 53.4% of transmission lines, and 3.0% of general property. This breakdown was the basis for saying that the bulk system contains relatively equal amounts of line and substation equipment.*
- (b) The reference "OMA costs account for about one-quarter of TFO revenue requirements" was not intended to represent an exhaustive study of OMA costs as a percentage of total TFO revenue requirements. Therefore, there is no detailed analysis and supporting schedules beyond the observation that "about one-quarter" of the TFOs' revenue requirements consist of the cost of operations. For example, if you refer to the AltaLink 2004 to 2007 GTA, Schedule 4.1 shows forecast operations costs of \$51.4 million in 2007, and forecast revenue requirement of \$216.2 million. When the forecast operations cost is divided by the total revenue requirement, the result is 23.8%. Similarly, in ATCO Electric's 2003 to 2005 GTA, Schedule 4-B-1 shows forecast operations costs of \$45.7 million in 2005 and a total revenue requirement of \$165.5 million. In this case, operations represent 27.6% of the total revenue requirement. Further information on TFO revenue requirements is available from the TFO applications.

Preamble: The AESO states:

Recovery of system costs in this manner thus allows the bulk system and local system costs to be recovered through a single system charge with billing capacity and usage components. This provides a simpler rate and, in the AESO's opinion, provides a better signal that customers can respond to and manage. A rate with a combined system charge also better aligns with the AESO's contribution policy which differentiates only between system-related and customer-related costs.

Reference: Section 4 – 2007 Rate Design, Page 17 of 53.

Request:

- (a) In deciding to combine the recovery of bulk system and local system costs into a single system charge, please indicate the amount of weight the AESO has placed on:
 - (1) AESO administrative benefits of a simpler rate
 - (2) Benefits to AESO customers of a simpler rate
- (b) Please provide details to support the AESO claim that the combined charge provides a “better signal that customers can respond to and manage.” Include in the response any expected savings on the transmission system in the short term and long term from the proposed rate that results from this “better signal”.
- (c) Please explain how this rate better aligns with the AESO's contribution policy which differentiates only between system-related and customer-related costs when the customer contribution policy only relates to POD costs and potentially local system costs (for radial lines) and does not reflect bulk system costs for loads.

Response:

Revisions to part (b) indicated in italics.

- (a) The AESO's primary consideration in proposing a single charge to recover both bulk and local system costs was the provision of a better price signal to customers. A secondary consideration was alignment with the AESO's customer contribution policy.

The AESO placed little weight on AESO administrative benefits, as the AESO billing system can accommodate either both costs separately or combined and administrative benefits would be minimal.

- (b) The AESO initially considered the bulk and local charge under the 2006 DTS rate in comparison to the system charge under the proposed 2007 DTS rate. The AESO

considers a single demand (\$/MW) charge based on billing capacity to provide a clearer price signal than two demand charges where one is based on coincident demand and the other is based on billing capacity.

The AESO also considered retaining bulk and local charges for the proposed 2007 DTS rate. The AESO again considered a single demand charge of \$1,176.00/MW of billing capacity to provide a clearer signal than two demand charges of \$830.00/MW of billing capacity for the bulk system and \$346.00/MW of billing capacity for the local system.

As discussed in response to Information Request IPCAA.AESO-028, the AESO considers that if customers receive and respond to a clear price signal, the transmission system will be able to be planned and operated in an orderly and efficient manner, and will be able to better avoid violation of limits with respect to thermal capacity, voltage, and stability.

Given that the bulk and local transmission system has a 5 to 10 year planning horizon, the AESO does not expect any economic savings in the short term that would be attributable to impacts on system planning from a better price signal. A better price signal could affect operation of the transmission system, however, if that signal leads to avoidance of violation of thermal capacity, voltage, and stability limits.

In the long term, a price signal that supports the orderly and efficient development of the transmission system could also result in deferral of system projects. If, for example, a \$100 million bulk transmission system project is deferred by one year, savings on the order of \$7 million would accrue to transmission ratepayers.

- (c) The customer contribution policy in the AESO's Terms and Conditions defines both customer-related costs (in Articles 9.3 (a) and (b)) and system-related costs (in Article 9.3 (c)).

Under the contribution policy, customer-related costs generally include costs related to the substation and associated radial line serving the customer, and are covered by investment up to the maximum allowed by the investment function. The same costs are represented in the point of delivery function in the cost causation study underlying the AESO's rates. As a result there is very good alignment between average customer-related interconnection costs and costs recovered through the POD charge.

Also under the contribution policy, system-related costs are included in TFO costs and recovered over all customers through other components of the DTS interconnection charge. The two-part contribution policy (distinguishing between customer-related and system-related components) is mirrored by a two-part DTS interconnection charge (with distinct POD and system charges).

Preamble: The AESO states:

...The requirement for such a service was raised during the AESO's 2005-2006 GTA proceeding itself (summarized on page 30 of EUB Decision 2005-096), and the AESO committed to examining the requirement for a backup or standby service in its next tariff application.

Reference: Section 4 – 2007 Rate Design, Page 31 of 53.

Request:

- (a) Is it the AESO's understanding that the Alberta government generally supports the development of cogeneration for serving domestic load and for export? Please cite references in support of AESO's views. If no, please provide a full explanation.
- (b) Does the AESO believe that cogeneration can be economically attractive and environmentally responsible due to the very high efficiency and low emissions when compared to other non-renewable natural resources? If no, please provide a full explanation.
- (c) Is it the AESO's opinion that the Alberta government's policy on generation generally supports all forms of generation? If no, please provide a full explanation.
- (d) Is it the AESO's understanding that the AESO has in the past and will continue in the future to recognize, within limits, that different forms of generation have unique and different circumstances requiring different treatment? Please cite any examples, either historical or currently under consideration. If no, please provide a full explanation.
- (e) Please confirm that (1) the AESO has devoted significant staff resources to addressing problems related to wind generation in southern Alberta including approval of new transmission, (2) the AESO has devoted considerable resources to advancing the 500 kV north south transmission line to largely accommodate new coal-fired generation in the Edmonton area and (3) devoting considerable resources to solving standby tariff problems in support of cogeneration would be appropriate. If no, please provide a full explanation.
- (f) Is the AESO aware of any jurisdiction where a Standby tariff (or its equivalent) is designed to grant rate relief not entirely justified by cost causation but where such a tariff is also designed to encourage or incent cogeneration development? If so, please cite references.
- (g) Does the AESO agree that the rate principle described as the "provision of appropriate price signals that reflect all costs and benefits, including in comparison with alternative sources of service" could recognize the "benefits" that cogeneration brings to AESO Customers and Alberta in general? If no, please provide a full explanation.

- (h) Is it the AESO's understanding that the unique requirements of cogeneration type loads lead to standby tariffs, or their equivalents, in many jurisdictions? Please cite all jurisdictions studied, whether they employ a standby tariff or not and if so how that standby tariff is designed. If no, please provide a full explanation.
- (i) Does the AESO agree that, with respect to the AESO's Long Term Adequacy Committee review of generation supply in Alberta, there are concerns that future generation will be inadequate to meet load and that it therefore follows that transmission tariffs should not create any unnecessary barriers to entry for generation development? If no, please provide a full explanation.
- (j) Does the AESO agree that onerous and/or high-cost standby tariffs may be perceived as barriers to entry for generators to develop in Alberta? If no, please provide a full explanation.

Response:

Revisions to part (d) indicated in italics.

- (a) The AESO is not aware of any preferential support by the Alberta government for the development of cogeneration. For example, the Alberta Department of Energy's June 6, 2005 policy paper titled *Alberta's Electricity Policy Framework: Competitive – Reliable – Sustainable* states on page 27:

As illustrated in Figures 2 and 3, the majority of the capacity additions since 1996 were gas-fired units (primarily cogeneration), with Genesee 3 a recent notable exception. Although the prospect of being able to sell energy into a competitive market can contribute to a decision to build co-generation, the primary driver is "within the fence" of the co-generation owner, to ensure that the plant will meet its processing needs. The Department is of the view that such plants are typically not installed to be timely in meeting the supply requirements of the electricity market.

- (b) The AESO agrees with the Department of Energy's view, as stated in part (a) above, that for a cogeneration plant "the primary driver is 'within the fence' of the co-generation owner, to ensure that the plant will meet its processing needs."
- (c) The AESO agrees that the Alberta government's policy does not favour particular forms of generation. The Alberta Department of Energy's policy paper referenced in part (a) above states on page 47:

The Department does not support one type of generation over another but rather allows competitive market forces to determine the appropriate generation mix (e.g. no fuel use policy).

- (d) In accordance with section 8(1) of the Transmission Regulation, the AESO must:
 - (e) *[take] into consideration the characteristics and expected availability of generating units, plan a transmission system that*

- (i) *is sufficiently robust to allow for transmission of 100% of anticipated in-merit electric energy referred to in section 17(c) of the Act when all transmission facilities are in service, and*
 - (ii) *is adequate to allow for transmission, on an annual basis, of at least 95% of all anticipated in-merit electric energy referred to in section 17(c) of the Act when operating under abnormal operating conditions;*
- (f) *make arrangements for the expansion or enhancement of the transmission system so that, under normal operating conditions, all anticipated in-merit electric energy referred to in clause (e)(i) and (ii) can be dispatched without constraint;*

The AESO agrees that the characteristics and expected availability of generating units were also considered in the past, although such considerations were made in the context of a vertically integrated electric industry prior to 1996. Despite similar considerations, decisions with respect to the specific generating units installed may therefore have been different prior to industry restructuring than in the current competitive generation market.

When planning the transmission system to accommodate a generating unit, the primary considerations are the individual operating characteristics of the unit and its potential impact on the transmission system. All generating units must first meet all applicable transmission interconnection requirements. Specific operating characteristics which are then considered include the size of the generating unit, the reactive power capabilities of the unit, the expected time and consistency of utilization of the transmission system, the potential for loss of the generating unit, the ramp rate of the unit, and its location on the transmission system with respect to the location and characteristics of other loads and generating units in the area.

For example, the system can be more readily planned for baseload generation that operates all day every day in comparison to intermittent generation that operates only during certain periods. The system may also be more readily planned to accommodate a single generator that is small relative to load in the area, in comparison to multiple generators that exceed the load in an area.

In the AESO's opinion, these considerations existed in the past, apply in the present, and will continue in the future. These considerations also frequently result in planning decisions which are unique to the generating unit being interconnected.

- (e) The AESO considers that it has devoted appropriate and considerable resources to:
- addressing concerns with respect to wind generation in southern Alberta,
 - advancing the north-south 500 kV project to carry power from northern Alberta to central and southern Alberta, and
 - developing a rate that fairly, objectively, and equitably allocated costs to and recovers costs from backup services.

The consideration of backup service is described in section 4.6 of the AESO's 2007 GTA.

The AESO also notes that these three undertakings are quite different in nature, and devoting an appropriate level of resources to each does not imply devoting an equal level of resources to each.

- (f) The AESO is aware that such tariffs have been implemented in some jurisdictions. For example, *Rate Structures for Customers With Onsite Generation: Practice and Innovation* by L. Johnston, K. Takahashi, F. Weston, and C. Murray (National Renewable Energy Laboratory, Golden, Colorado, December 2005) states (p 63):

In many states, DG [distributed generation] ratemaking is being taken up as part a broader effort to develop a set of state policies to promote DG and capture its expected economic, environmental, and reliability benefits for customers, utilities, and society as a whole. These anticipated benefits go beyond a strict evaluation of electric system costs and benefits of a customer's individual installation. State regulatory agencies may want to design rate treatments to affirmatively promote distributed resources, including clean DG.

The report identifies Massachusetts, New York, and Rhode Island as states with rates developed, at least in part, to achieve public policy goals.

- (g) The AESO considers that, in the context of the transmission tariff, reflecting all costs and benefits refers to all costs and benefits relating to the transmission system. If any “benefits” of cogeneration are external to the transmission system, it would be inappropriate to incorporate such benefits into the rate design of the AESO’s tariff (at least in the absence of specific legislative direction to do so).
- (h) The AESO understands the requirements of onsite generation, whether utilizing cogeneration or other technologies, frequently leads to the development of backup or standby rates. For example, *Rate Structures for Customers With Onsite Generation: Practice and Innovation* by L. Johnston et al. states (p 7):

In New York, Massachusetts, and Oregon, utilities used existing cost-of-service studies to determine DG [distributed generation] standby rates. The availability, or lack, of specific cost analysis has been cited as a concern in a number of jurisdictions.

- (i) The Long-Term Adequacy Working Group has not assumed there will be inadequate generation to meet load. The Working Group’s objective, to date, has been the implementation of metrics to monitor the balance between supply and demand, and, if the supply-demand balance becomes a concern, to ensure bridging actions exist that will address the concern. Please refer to the response to Information Request TCE.AESO-034 (b) for additional information.
- (j) Please refer to the response to Information Request TCE.AESO-034 (b).

Preamble: The AESO states:

...The AESO estimated that 1,500 to 2,000 MW of load could potentially request backup service and incur minimal cost for utilizing it.

Reference: Section 4 – 2007 Rate Design, Page 34 of 53.

Request:

- (a) Please provide the details on how the amount of potential backup service was estimated.
- (b) Was any consideration given to mitigation methods to insure only loads associated with cogeneration or generation facilities would be able to request backup service?
- (c) Does the AESO have an estimate of the amount of load required to backup generation?

Response:

Revisions to part (a) indicated in italics.

- (a) Please refer to the response to Information Request BR.AESO-004.

The estimate resulted from discussions within the AESO rather than detailed numerical analysis, and was based on the following considerations.

- (i) *As detailed in Schedule BR.AESO-003 (a)-A1 provided in response to Information Request BR.AESO-003 (a), there are 51 DTS accounts with load factors less than 10% and average billing capacity of 13 MW, representing a total billing capacity of 663 MW. The AESO expects a majority of these accounts may request service on a backup rate.*
- (ii) *During stakeholder consultation, in response to a question about quantifying the need for backup service the AESO was advised that ten customers had indicated interest in about 765 MW of backup service, with additional interest expressed in backup service for future unquantified loads.*
- (iii) *As discussed in response to Information Request IPCAA.AESO-047 (b), there is about 2,063 MW of load connected at 64 substations in Alberta where customers have contracted with the AESO for both load and generation service. The AESO suggests it is likely a majority of these accounts may request service on a backup rate.*

- (iv) *As discussed on page 37 of section 4 of the AESO's 2007 GTA, the Northeast Alberta transmission system is being developed to support 425 MW of backup load, with a total of 1,100 MW of backup load forecast to be interconnected.*
- (v) *As discussed in response to Information Request BR.AESO-004, the AESO understands that some higher load factor customers have backup-type loads which could be separated from their primary loads for service on a backup rate.*
- (vi) *Also as discussed in response to Information Request BR.AESO-004, the AESO understands some customers may add incremental load if an inexpensive backup-type service is available.*

There is overlap between the amounts provided above, and therefore they should not be summed in an attempt to determine a total potential backup load. However, given these considerations, as stated on page 34 of section 4 of its 2007 GTA, the AESO estimates that 1,500 to 2,000 MW of load could potentially request backup service if only minimal costs were attributed to such service.

Utilization of a backup service would depend on the rate applicable to the service, the alternative standard rate, and any conditions which may apply to transfers from the standard rate to the backup rate. The AESO has proposed changes to the standard DTS rate in its 2007 GTA, and had discussed during stakeholder consultation only a backup rate structure which converted the ratchet charges incurred by loads above contract capacity into a usage (\$/MWh) charge which generated equivalent revenue at a 10% load factor. The AESO considers it inappropriate to develop a detailed forecast based on these limited parameters.

- (b) *As discussed on page 34 of section 4 of the AESO's 2007 GTA, the AESO considered conditions or restrictions on eligibility but considered the characteristics of backup service (short duration, infrequent, and unscheduled usage) could be exhibited both by loads associated with cogeneration or generation facilities and by low load factor load service. The AESO therefore concluded that, from a transmission system perspective, there is no cost or operational basis for distinguishing between backup service to a generator and intermittent operation of a load service.*
- (c) *Please refer to the response to Information Request IPCAA.AESO-047 (b).*