Reference: Section 4, page 11

Request:

Please provide a copy of the National Economics Research Associates (NERA) review.

Response:

Please see attached Assessment of AESO Transmission Cost of Service Analysis prepared by NERA Economic Consulting and dated October 31, 2006. The document was posted on the AESO’s website on November 7, 2006, as part of the AESO’s 2007 rates consultation.
Preamble: Table 4.3.7 shows the classification resulting from the Transmission Cost Causation Study (TCCS) while Table 4.5.1 shows the classification in the proposed rate design.

Reference: Section 4, DTS System Charge, pages 14-17

Request:
(a) Please explain the other options considered in addition to the “average and excess” method in arriving at the proposed rate design. For each option, please explain why the “average and excess” method is considered by the AESO to be preferable.

(b) Please explain fully why the AESO feels such a significant move to an energy component in the DTS rate is justified given the results of the TCCS.

Response:
(a) Options for the classification of transmission wires costs which were considered during the development of the proposed 2007 rate design included:
   • peak period (by season, time of day, or both)
   • coincident peak (1 CP, 12 CP, or 3W/9NW CP)
   • non-coincident peak
   • usage (energy) only
   • average and excess
   • average and peak
   • minimum-size (minimum-system) method
   • minimum-intercept method
   • marginal cost approaches

   These options were considered to varying degrees of detail. Some were raised and discussed during stakeholder consultation, while others were discussed internally by the AESO. The following considerations led to the AESO’s conclusion that the average and excess approach provides a sound basis for the design of the DTS rate.

   (i) Peak period and coincident peak approaches both presume coincidence of transmission system loading with either specific seasonal or daily periods or with system peak. The examination of transmission system loading prepared for the AESO’s 2007 GTA did not support such a presumption of coincidence. Without evidence of coincidence, use of any of these approaches would be contrary to the cost causation basis for the DTS rate, as discussed in section 4.3.2 of the Application and in Appendix D.

   (ii) Minimum-size and minimum-intercept methods can be applied to determine demand- and usage-related cost classification, as was done in the Transmission
**Cost Causation Study.** Application of either method results in a relatively high demand-related classification, reflecting the demand-driven, fixed costs of a transmission system. However, utilization of either method for rate design also implies that every customer’s demand has a more-or-less equal probability of causing a need for system reinforcement, irrespective of load factor. The AESO considers that high load factor customers have a greater likelihood of causing a need for system reinforcement, and therefore proposes that the average and excess approach is more appropriate for cost allocation.

(iii) Marginal cost approaches may provide insight into future cost causation considerations. In general, the AESO does not expect that the factors affecting utilization of the transmission system today will change materially in the future. As well, embedded (rather than marginal) cost analysis has traditionally been used in Alberta cost studies.

(iv) Classification as totally usage-related ignores the fundamental fact that the transmission system is generally planned and operated to meet peak demand conditions, whenever they occur. Billing based totally on usage would provide a very weak signal for customers to manage their load profile.

(v) In contrast, classification as totally demand-related reflects the primary cost driver of the transmission system, but billing totally (or primarily) on non-coincident peak assumes that each customer is equally likely to drive costs of the system. In general, customers who use the system more consistently or for more hours in a period are more likely to drive costs. A common method used to reflect this greater degree of cost causation by higher load factor customers is to allocate more costs based on usage.

(vi) “Average and excess” and “average and peak” approaches are similar in that “average” demands determine the usage-related costs which are recovered through a usage charge or an average demand charge. The approaches differ primarily in that demand-related costs are determined using non-coincident peaks in the average and excess method and coincident peaks in the average and peak method. Since the examination of transmission system loading prepared for the AESO’s 2007 GTA did not demonstrate coincident loading of transmission system components, the AESO considered the average and excess method to be more appropriate for rate design.

(b) The AESO supports the functionalization and classification provided in Table 4.3.7 as an appropriate and sound analysis of transmission system wires costs. The conclusions of the 2006 Transmission Cost Causation Update as summarized in the table reflects the underlying long-term fixed nature of the transmission system, where transmission capacity is added in large increments and does not generally respond to variations in usage.

However, when rates are designed to meet a principle of fairness, objectivity, and equity, it may not be appropriate to translate the cost classification directly into corresponding rate components. For example, even if costs are fully classified as demand-related, it seems unfair that a 20 MW customer operating 30 hours a month pay the same costs as a 20 MW customer operating 600 hours a month. The latter customer is utilizing the transmission system for a longer period of time and is more likely to cause the
transmission system to be expanded or upgraded. The AESO is of the view it is reasonable that such a customer should therefore pay a greater share of transmission system costs.

The AESO reached this conclusion after considerable discussions with stakeholders and internally on costs related to, and cost recovery for, the provision of backup or standby service. Although transmission system costs are primarily demand-related, loads of varying load factors are reflected differently in transmission system plans. Costs should therefore also be allocated differently to loads of varying load factors. A common method of allocating costs to reflect load factor is by increasing the usage-related component, and the AESO has incorporated such an approach in the proposed 2007 DTS rate.

The AESO further notes that the cost classification in the proposed DTS rate design does not vary radically from that of prior DTS rates. The classification of transmission wires costs in the AESO’s 2005, 2006, and proposed 2007 DTS rate designs is as follows:

<table>
<thead>
<tr>
<th>Classification for Rate Design</th>
<th>2005</th>
<th>2006</th>
<th>Proposed 2007</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fixed</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Demand</td>
<td>60.0%</td>
<td>56.0%</td>
<td>66.3%</td>
</tr>
<tr>
<td>Customer</td>
<td>-</td>
<td>24.0%</td>
<td>5.0%</td>
</tr>
<tr>
<td>Subtotal Fixed</td>
<td>60.0%</td>
<td>80.0%</td>
<td>71.3%</td>
</tr>
<tr>
<td>Usage (Energy)</td>
<td>40.0%</td>
<td>20.0%</td>
<td>28.7%</td>
</tr>
<tr>
<td>Total</td>
<td>100.0%</td>
<td>100.0%</td>
<td>100.0%</td>
</tr>
</tbody>
</table>

The AESO observes that the usage-related classification for the proposed 2007 rate is an increase of about 9 percentage points from the 2006 usage-related classification, and a decrease of about 11 percentage points from the 2005 usage-related classification. These classification changes result from the detailed examination of wires costs provided in the AESO’s 2006 and 2007 GTAs, and reflect the rate design principles provided in section 4.2 of the AESO’s 2007 Application.

The AESO therefore considers that the usage-related component in the proposed DTS rate is appropriate based on the results of the Transmission Cost Causation Update and the consideration of fundamental rate design principles.
Reference: Section 4.6, Back Up Rate

Request:

Has the AESO developed a forecast of the number of customers that may be eligible for and use a Back-Up Rate and what the potential revenue might be? If so, please provide the forecast, along with such underlying calculations and assumptions as may be necessary to understand the forecasts. If not, please explain why it was not considered necessary to develop such a forecast.

Response:

The AESO has not specifically developed a forecast of customers that may utilize a backup service. Such utilization may depend on the specific structure of the applicable rate. The AESO has also not proposed a separate backup rate in its 2007 GTA, as it determined the proposed DTS rate was appropriate for the full range of load factors, including those expected for backup usage.

In considering a backup service, the AESO concluded that all services with low load factors should be treated similarly, whether the low load factor resulted from backup use associated with a generator or from intermittent equipment operation at a load service. All low load factor customers could therefore be potentially eligible for a backup-type rate. As summarized in Table 4.5.2 on pages 25-27 in section 4 of the AESO’s 2007 Application, the AESO has 49 load services with load factors of less than 10%. These 49 customers represent 578 MW of DTS billing capacity and 8,134 MWh of metered energy per month. The average bill under the AESO’s 2006 DTS rate for those customers is $19,991/month, and therefore represents $19,991/month × 12 months = $11,754,708 of annual revenue, or about 1.9% of the AESO’s 2006 DTS revenue requirement.

In addition to these low load factor customers, the AESO understands that some higher load factor customers have backup-type loads which could be separated from their primary loads. As well, the AESO understands some customers may add incremental load if an inexpensive backup-type service is available. In total, as stated on page 34 of section 4 of the Application, the AESO estimates that 1,500 to 2,000 MW of load could potentially request backup service. This amount of backup service, if served under the AESO’s 2006 DTS rate, would represent about $35 million of annual revenue, or about 6% of the AESO’s 2006 DTS revenue requirement.
Preamble: The AESO states that in neighbouring jurisdictions most export transactions occur under hourly, monthly and annual rates.

Reference: Section 4.8, Export and Import Services

Request:

Please provide copies of the relevant rates from the neighbouring jurisdictions.

Response:

The rates from British Columbia, Saskatchewan, and Montana are provided as Attachments BR.AESO-005-A, -B, and -C.
Preamble: The AESO has proposed to collect all components of the rate on a usage basis.

Reference: Section 4.8.1, Rate XTS

Request:

As the rate is firm and non-recallable, please describe the nature and extent to which the AESO considered designing the rate such that a portion was fixed in nature. If such a design was not considered, please explain.

Response:

The AESO considered a fixed ($/MW) component during development of the XTS rate, but abandoned it on the basis that export capacity is not available in some hours due to transmission system conditions.

A fixed ($/MW) rate component is generally appropriate to charge for capacity that is available to the customer throughout the billing period or other longer period. For inter-provincial transactions, export capacity is not available in some hours due to transmission system conditions and constraints in Alberta, British Columbia, and Saskatchewan.

Maximum export capacity is calculated by the AESO in each hour as the Alberta export Available Transfer Capability (ATC). ATC in the last quarter of 2006 ranged from 0 MW to 795 MW, with ATC below the 795 MW maximum for more than 90% of the time.

The AESO considers it inappropriate to apply a fixed charge when the capacity to which the charge relates is sometimes not available. The XTS rate was therefore designed on a usage ($/MWh) basis applicable only when export capacity is actually available.
Preamble: In Order U2006-307 the Board approved an amendment to Rate FDS.

Reference: Rate FDS

Request:

Does the AESO consider it appropriate to institute a deferral account to true up variances in revenue attributable solely to Fort Nelson? Please explain.

Response:

No, the AESO does not consider it appropriate to institute a single-service deferral account.

Rate FTS (FDS in the AESO’s 2006 tariff) is set to be equal to the AESO’s Rate DTS for the bulk system, operating reserve, voltage control, and other system support services components (that is, for all components except the local system and POD components). Costs for these components are incurred system-wide and cannot be assigned with any precision to individual customers’ services. It is not practical to attempt to true up variances between actual costs and actual revenues when actual costs for an individual service cannot be determined.

Rate FTS does not include a POD component as BC Hydro provides its own facilities. No variances therefore arise with respect to a POD component.

The only Rate FTS component which applies and differs from those of Rate DTS is the local system component of the interconnection charge. Although the local system component is different, the charge itself is based on a levelized series of payments which recover average depreciation, return, tax, and operations and maintenance (O&M) expense amounts for ATCO Electric. These amounts are not tracked by individual facility such that they could be assigned to the facilities used for the Fort Nelson service. In particular, a large component of O&M expense is general in nature and cannot be assigned with any precision to individual facilities. The AESO therefore considers it unreasonable to attempt to true up variances between actual costs and actual revenues for the local system component.

For these reasons the AESO does not consider it appropriate to institute a deferral account for Rate FTS. Because of the system-wide nature of the majority of costs recovered through Rate FTS, the AESO considers it appropriate to include Rates FTS and DTS together when reconciling its deferral accounts to true up variances in revenue and costs.
Preamble: In section 6 of the Application, the AESO proposes to replace the current definition for “Reliability Management System” with a new definition of “Reliability Standards” for the purpose of creating more alignment between the Tariff and the Transmission Regulation.

The Board wishes to understand the implications of this proposed change.

Reference: Proposed “Reliability Standards” Definition, Section 6, p. 3 of 47

Request:
(a) Please confirm that the current Reliability Management System agreement with the WECC will not be terminated as a result of this change. If this cannot be confirmed, please explain.

(b) The Board notes that the proposed definition of “Reliability Standards” references both WECC and the North American Reliability Council (NERC). Does the AESO expect that it will enter into additional agreements with these agencies? If so, please briefly describe the nature of the additional reliability standards agreements that the AESO anticipates entering into with each agency.

(c) Please specify which sections of the Transmission Regulation require the AESO to drop reference to the RMS Agreement in the T&Cs in favour of a new definition of “Reliability Standards”.

(d) Please confirm that, notwithstanding that the Board has not yet adopted the reliability standards definition proposed in the Application, the Alberta transmission system has been operated by the AESO at a reliability standard consistent with the Transmission Regulation since it was enacted in 2004. If this cannot be confirmed, please explain.

Response:
(a) Not confirmed. It is expected that the current Reliability Management System (RMS) agreement will be superseded by a new agreement with WECC. The WECC has informed its members that it expects that the RMS agreement will be terminated on or about July 1, 2007. However, the current RMS agreement will remain in force until the new agreement is completed.

(b) The AESO expects that one agreement with the WECC will be sufficient to establish a business relationship with the WECC that will address how mandatory reliability standards will be implemented in Alberta. The agreement is expected to define the relationship between the AESO and the WECC and NERC, describe how mandatory reliability standards will be approved in Alberta, and outline how compliance to the reliability standards will be monitored and enforced.
(c) The *Transmission Regulation* in paragraph 1(1)(e) defines "reliability standards" more broadly than the definition of "RMS" in the AESO's currently-approved tariff, and in Part 2 requires the AESO to adhere to the reliability standards as defined in the Regulation. Although the *Transmission Regulation* does not require the AESO to drop reference to the RMS agreement, the AESO considered it appropriate to align its definition with the definition in the *Transmission Regulation*, especially in anticipation of the changes proposed by WECC as described in (a) above.

(d) Confirmed.
Preamble: At p. 5 of Section 6, the Application states:

“During the AESO’s stakeholder consultation process for the 2007 GTA, the AESO originally proposed to make a number of revisions to Article 5 to align the interconnection process practices with the Tariff. Since that initial consultation, the AESO has undertaken additional stakeholder consultation relating to business practices in respect of interconnection queue management and compliance milestones which may have an impact on Article 5. As such, the AESO does not propose any major changes at this time. The AESO proposes only minor refinements to Article 5 in this Application, and upon completion of the business practice consultation process, the AESO will include any necessary changes to Article 5 in a future update of its Terms and Conditions.”

Reference: Section 6.3 – Article 5 – System Access Application, p. 5 of 47

Request:

Please provide a copy of the document describing the interconnection queue management business practices referenced in the above noted passage.

Response:

Attached is a copy of the draft interconnection queue management business practices as proposed to stakeholders in May 2006 (BR.AESO-009 A). This discussion paper was the topic of stakeholder consultation, and the AESO posted stakeholder comments on the proposal on September 7, 2006.

The AESO continues to work towards refining business practices for project sequencing, and posted a letter to stakeholders on November 29, 2006 (attached as BR.AESO-009 B) identifying the goal of having the business practices finalized and implemented by March 2007.
Preamble: Section 6.5.1 - Applicable Tariff for System Access Requests and Customer Contribution Calculations for Increases in Contract Capacity, pp. 9-13 of 47

Request:

(a) Does the AESO agree that the proposal to recalculate contributions for requested increases in contract capacity on the tariff in place at the time the capacity increase is made rather than on the basis of the tariff in effect when the original amount of the customer contribution was determined creates a potential for customers to “game” the contribution policy? If not, please explain.

(b) In light of your response to a) above, please comment on whether this tendency to game possible changes in the contribution policy could be mitigated to an extent if customers requesting contract increases were to be at risk of losing their “slot” in the AESO’s interconnection project queue.

Response:

(a) For clarity, the AESO proposes to base the contribution adjustment for contract capacity increase requests on the customer contribution policy at the time of the original request in cases where the construction of new transmission facilities is not required. Only when a customer’s contract capacity increase request necessitates the construction of new transmission facilities, does the AESO propose that the customer contribution policy in effect at the time of the request is to be applied to the cost of the new transmission facilities required. This treatment is considered to be fair and reasonable as it is the same as that which would apply to a new customer requesting system access service. The AESO is of the view the customer’s ability to game the contribution policy is limited since the contribution policy’s primary goal has been consistent since the year 2000. That is, it is set such that 80% of projects do not pay a contribution while 20% do. Since the proposed investment level is directly tied to rates and the “80/20 rule” continues to guide the amount of investment available, the outcomes should be similar, and therefore intergenerational inequities and opportunities for gaming should be minimal.

(b) As noted in (a) above, the AESO submits that under the proposed terms and conditions, a customer’s ability to game the contribution policy is limited, and in cases where a customer’s contract capacity increase request necessitates the construction of new transmission facilities, the project would be subject to the same rules and processes as any other new customer interconnection request. In both cases, project milestones and compliance with those milestones are designed to effectively manage customers’ interconnection requests and subsequent tariff treatment.
Preamble: The proposed Article 9.2 reads as follows:

“All Customer Contributions and System Contributions required under this Article 9 as determined at the time the Customer executes the necessary agreements signifying commitment as per the AESO’s interconnection processes, must be paid by the Customer before the start of construction of transmission facilities to provide the requested service. Payment must be made by way of electronic funds transfer or wire transfer to the bank account specified by the AESO.”

Reference: Section 6.5.1 – Proposed Article 9.2 – Payment of Contributions, p. 11 of 47

Request:

(a) What are the “necessary agreements signifying commitment” for the purposes of a proceeding with an interconnection project and determining the customer’s contribution?

(b) Please provide “pro forma” versions of each of the necessary agreements identified in the response to a) above.

(c) Please confirm that all commitment agreements that the AESO enters into with interconnecting customers reflect the pro forma agreements provided in the response to b) above. If this cannot be confirmed, please describe the nature of the permitted variations and the rationale for such variations in respect of each type of agreement referenced in the response to b).

Response:

(a) As noted in Section 6.6, page 33 of the Application, the AESO has undertaken a stakeholder consultation process to review its business practices relating to interconnection queue management and compliance milestones which will not only impact Article 13, but will also impact the application of Article 9.2 as it will outline the necessary agreements signifying commitment, which in turn will dictate the appropriate tariff treatment. The process will effectively modify to the extent necessary the AESO’s current business practice document called ‘Customer Commitment Determination During Interconnection Process’. A copy of this document is attached to this response as Attachment BR.AESO-011-A. The business practice document outlines the various obligations of the customer and the necessary compliance milestones which the AESO will consider as an indication that the customer is committed to their project. Primarily, the AESO relies on the Construction Commitment Agreement (CCA), but may also rely on a CCA waiver or a System Access Service Agreement (SASA) depending on the project circumstances. The CCA waiver indemnifies the AESO from any project cancellation costs and allows wire owners who own both distribution and transmission and are legally the same entity to make the necessary security arrangements between themselves. Distribution Facility Owners (DFO) not affiliated with a TFO and direct connect customers are still required to sign the CCA. A SASA is used as commitment in
circumstances where a customer’s contract capacity increase does not require the construction of new transmission facilities.

(b) The SASA and the CCA are available in the Appendix of the existing and proposed Tariff (Application, Section 7, page 51 and page 66 respectively). A pro forma CCA waiver is attached to this response as Attachment BR.AESO-011-B.

(c) Confirmed. Please see part (a) above for additional information.
Reference:  Section 6.1.1 – Prepaid Operations and Maintenance, pp. 13-15 of 47

Request:

(a) Please confirm that the purpose of the prepaid O&M charge is to cover incremental O&M costs expected to be incurred by the TFO as a result of the interconnection of the new customer. If this cannot be confirmed, please explain.

(b) Please explain the rationale for using the optional portion of a new facility cost for the purposes of the determination of the prepaid O&M amount to be recovered from an interconnecting customer. In particular, please explain why the pre-paid O&M charge should not be based on the full amount of the incremental TFO O&M cost expected to arise from the new customer’s interconnection.

(c) Please confirm that prepaid O&M charge is only intended to cover off incremental TFO O&M costs arising from a new interconnection and not incremental TFO labour or other costs that may be capitalized as part of the TFO’s capital maintenance expenditures. If this cannot be confirmed, please explain.

(d) If your response to c) confirms that the prepaid O&M charge is intended to only target incremental O&M costs and not incremental labour and other costs that may be capitalized, please explain why it would not be appropriate to also consider capitalized portion of incremental costs as part of the determination of a prepaid O&M charge.

(e) In light of your answer to c) above, please provide the AESO’s estimate of the average incremental annual O&M expense that arises from a dollar of investment in a new interconnection facility.

Response:

(a) The AESO generally considers including an O&M amount in customer related costs reflects the full costs the TFO is expected to incur as a result of interconnecting a new customer.

(b) The AESO proposes that O&M costs associated with standard service obtained through Standard Facilities are properly recovered through average rates, and therefore including an O&M amount in the customer related costs for standard facilities (used to determine the contribution) is not necessary. The AESO understands TFOs include in their revenue requirements total forecast O&M expenses that cover all expected O&M regardless of whether contributions were made for new services or not, and therefore all O&M costs are already included in the AESO’s average rates. The AESO notes it has been historical practice for O&M expenses, including any capital expenditures for standard system access service provided by the AESO and regulated TFO, to be recovered through average rates. The AESO also understands the distribution
companies' (Discos') contribution policies include prepaid O&M only for facilities in excess of Standard (i.e. optional).

As such, the AESO proposes to include an O&M component in facilities costs in excess of Standard (i.e. optional) but not in Standard Facilities costs primarily for the following reasons:

- The O&M adder to the contributions for facilities in excess of Standard ensures customers selecting optional facilities receive an appropriate price signal that the postage stamp rate that they will pay going forward reflects only costs that are associated with the standard level of service provided by the AESO.
- Applying the O&M adder to the cost of standard facilities would create intergenerational inequity as customers prior to the 2005/2006 tariff were not subject to this incremental charge.
- The proposed tariff maintains harmonization between the AESO and the DISCOs, since as noted above it is the AESO’s understanding that the DISCOs currently apply an incremental O&M charge only to optional facilities.

(c) Confirmed. Also please see the response to (b) above.

(d-e) The AESO continues to rely on the definition of O&M applied in the 2005/2006 Application. The AESO interpreted the O&M charge to represent only O&M expenses required to maintain system access service. The basis for the 12% charge (approved in Decision 2005-096) was discussed in the AESO’s 2005/2006 GTA Information Request response ALPAC.AESO-003 (a-h) and is attached to this response as Attachment BR.AESO-012.
Preamble: At p. 14 of Section 6, the Application states:

“The AESO also suggests that the O&M charge on standard facilities does not achieve the economic efficiencies intended by the Board. The O&M charge would create additional accounting treatment concerns and infrastructure requirements for Transmission Facility Owners (TFOs). Additional time and resources will be required to modify current processes and accounting infrastructure to effectively separate and track capital costs of the transmission facilities as compared to traditional expense treatment for O&M. New procedures and processes would also be required to ensure O&M costs are being recovered correctly and are not recovered in other components of the TFOs revenue requirement.”

Reference: Section 6.1.1 – Prepaid Operations and Maintenance, pp. 13-15 of 47

Request:

(a) Please explain what the AESO understands the “economic efficiencies intended by the Board” to be as referenced in the above noted passage.

(b) As compared to the procedures adopted by the TFO’s in response to the prepaid O&M provisions approved in Decision 2005-096, please explain what additional accounting treatment concerns and infrastructure requirements that AESO considers the TFO’s would require.

(c) Please provide an estimate of the incremental TFO costs the AESO considers would stem from TFO activities referenced in part b) above. Please provide all assumptions used in deriving this estimate.

(d) Please explain why the AESO considers that the TFO’s would need to modify processes and accounting infrastructure to separately track capital costs in order to implement the prepaid O&M recovery mechanism approved by the Board in Decision 2006-096.

Response:

(a) The AESO considers there are two aspects related to “economic efficiency”, the first of which it believes may have been intended by the EUB.

The first is the economic signal provided to the customer in the form of a contribution payment where costs exceed available investment. As noted in Section 6.5.2, page 14 of the Application, the AESO suggests that such a signal only works if the customer contribution policy has a set investment level. Since, however, both the current (including O&M) and proposed (excluding O&M) investment policies are set based on the principle that 80% of projects are targeted not to pay a contribution, while 20% are to
pay a contribution, the level is not fixed but moves in order to achieve the target. In other words, with the O&M charge included in the cost of Standard Facilities, the cost function would increase but so would the investment level function, in order to maintain the target of 80%. On that basis, it seems to the AESO that the intended signal of including O&M is largely lost.

The second aspect is in relation to the AESO’s interpretation that the prepaid O&M component approved in Decision 2005-096 was intended by the EUB to be an actual pre-payment of O&M costs. This interpretation could, as the AESO understands it, result in an additional administrative exercise which it views as a potential inefficiency. Based on the interpretation that prepaid O&M forming part of contributions was intended to be actual pre-payment of O&M costs, it was assumed the TFOs should account for the O&M portion of the contribution separately (i.e. not to offset ratebase but apply it against actual O&M expenses over some period of time), which would require a new administrative exercise. To further ensure consistency in the overall tariff treatment, the AESO’s DTS rates would have to be adjusted to recover only the net O&M; that is, the total O&M expenses of the TFOs, less the amount forecast to be recovered through contributions.

(b) The AESO is of the understanding the TFOs may not have modified their processes to adapt the outcomes of Decision 2005-096, as described in (a) above. Therefore, if the O&M component remains included in the costs in the 2007 tariff, and if in fact the AESO’s interpretation is correct that the O&M component is intended to offset O&M expenses and not ratebase, then the AESO expects the TFOs would set up processes and procedures to account for the prepaid O&M as an expense rather than simply applying total customer contributions as offsets to ratebase.

(c) The AESO does not have this information.

(d) Please see the response to (a) and (b) above. As stated, the AESO had previously assumed that the approved prepaid O&M was exactly that: prepayment of O&M expenses. However, upon further consideration the AESO believes the entire contribution determined on that basis could be treated as capital (as it understands has been the case historically in relation to the O&M component in contributions for optional facilities), since it is paid in one lump sum, and therefore has the actual effect of lowering the amount the TFO needs to invest in the project at that time (i.e. provides no-cost capital). Going forward, the O&M expenses would continue to be included in the TFO revenue requirements and recovered in total by the AESO’s tariff.

The AESO believes either approach could be reasonable, provided it complies with GAAP. The primary concern to the AESO is that the tariff and the signals provided by it to customers are fair and appropriate. This will be the case under either method as long as there is consistency between the assumptions behind the AESO tariff and the revenue requirements and accounting treatments of the TFOs.

Reference: Customer Contribution Study, p. 19

Request:

Please provide a copy of the relevant portion of the NARUC Electric Utility Cost Allocation Manual.

Response:

Preamble: The Customer Contribution Study indicates that a number of data points used to derive the small project cost function were based on “least cost estimates” rather than actual observed small project costs. The Board wishes to clarify how the least cost estimates were derived.


Request:

Please provide a detailed derivation of one of the least cost estimates shown in Table 5 of the Customer Contribution Study.

Response:

The least cost estimates shown in Table 5 were excerpted from Table 4.10.1 on page 42 of section 4 of the AESO’s 2006 General Tariff Application filed on January 31, 2005, which provided least cost estimates for all DTS customers receiving COS (Customer-Owned Substation) Credits at that time. The excerpted estimates include all services with DTS Contract Capacities up to 7.5 MW (except for the Elmworth service which did not include substation costs in the estimate as discussed in the 2006 GTA). The details of those estimates were provided in response to Information Request COSC.AESO-003, which is attached to this response for reference.

As noted on page 41 of section 4 of the AESO’s 2006 GTA:

- *The least cost estimates used were ±30% estimates, were based on current costs, and assumed loads were connected at transmission voltages regardless of capacity.*

- *Loads were assumed to be transmission-connected even where the smaller capacity requirements would normally indicate a distribution connection. The transmission-connected assumption recognizes the reality that the load is connected to the transmission system, is subject to the AESO investment policy, and contributes to the AESO revenue requirement.*

DTS Contract Capacities and in-service dates were provided in a schedule in response to Information Request FIRM.AESO-234 (a), also in the AESO’s 2006 GTA proceeding and attached to this response for reference. Costs were escalated to 2007 using the Alberta Consumer Price Index.
Preamble: Table 4 and Table 5 illustrate the amount of contribution provided under previous approved and proposed future contribution policies. The Board wishes to better understand the impact of different contribution policies on the number of load interconnection projects undertaken.

Reference: Section 6, Maximum Investment Function, pp. 29-30

Request:

(a) For each of the years 1999 to 2006, please provide:
   o the number of interconnection projects undertaken,
   o the total dollar value of the projects completed.

(b) Please provide the following information in respect of each load interconnection project expected to be completed in 2006:
   o the total forecast cost of the project;
   o the DTS capacity of the project;
   o whether the contribution for the project was determined using the contribution policy set out in Decision 2005-096 or on the basis of the contribution policy in effect prior to that time

(Note: The Board does not require the identity of specific projects to be disclosed for this response).

(c) On the basis of the best forecast information currently available to the AESO, please provide in respect of each loading interconnection project currently forecast for 2007 and 2008
   o the total forecast cost of the project;
   o the expected DTS capacity of the project;
   o whether the forecasted project has secured a slot in the AESO’s “interconnection project queue” described in section 6.6 of the Application;
   o whether the application of the Decision 2006-096 contribution policy has been confirmed in respect of the project

(Note: The Board does not require the identity of specific projects to be disclosed for this response).

Response:

Please refer to Attachment BR.AESO-016.

It should be noted that many project construction schedules can span a number of years. Thus, the AESO has provided the project application date, the currently forecasted in-service-date (“ISD”), and where available, the actual ISD. The AESO considers that the actual ISD would be the most appropriate indicator of a project’s completion in a specific year.
Additionally, the AESO notes that the Customer Contribution Study categorized project “year” as the year in which the most recent estimate or final actual cost was received. That is to say, a project may have an estimate of $1.5M, submitted in 2005, however the actual ISD date for the project is 2006, and final actual costs could be reconciled in 2007.

As an example, Project # 433 – Fortis Christina Lake, has an application date of April 2004. At that time, the forecasted ISD was September 2006. The TFO forecasted project costs are $29.8M, and final actual reconciled project costs are expected to be submitted by the TFO in 2007. The categorization utilized in the Customer Contribution Study indicated that an estimate was received in 2005, which is the year recorded for indexing purposes.
Preamble: The Board wishes to clarify the AESO intended application of the customer contribution policy to merchant intertie projects.

Reference: Section 6.5 Customer Contribution Policy

Request:

(a) Please confirm that the AESO intends to apply the contribution policy used for load interconnection projects for the purposes of determining the customer contribution allowance made available for the interconnection of merchant interties with the Alberta transmission system. If this cannot be confirmed, please explain.

(b) In respect of project to interconnect a merchant intertie project with the Alberta transmission system, does the AESO assess whether forecasted AESO tariff revenue from merchant export and import rates exceeds the forecasted amount of the customer contribution? If not, please explain.

Response:

(a) The customer contribution policy only applies to customers signing a Demand Transmission Service (DTS) system access service agreement. It is expected that merchant inter-tie users would sign import or export system access service agreements and as such would not be eligible for investment under the AESO’s customer contribution policy.

The application of the customer contribution policy for the merchant transmission facility owner would be handled on a case by case basis. To date, for the Montana Alberta inter-tie project, the AESO has utilized the high level principles of the contribution policy to allocate the customer versus system related costs associated with the interconnection to the AIES but has not made any investment allowances for the project. Investment allowances, if any, would be case specific and would be outlined in any contractual arrangements undertaken between both parties.

(b) No. Please also refer to (a) above.
Preamble: The AESO proposes to amend Article 14.6 of the T&Cs to provide relief from the STS Regulated Generating Unit Connection Cost (RGUCC) charge in the event that a Regulated Generating Unit terminates service prior to the date defined as the Base Life in the Appendix to the AESO’s rates.

Reference: Section 6.7 – Contract Capacity Reductions for Regulated Generating Units, pp. 37-39 of 47

Request:

(a) Does the AESO agree that the termination of service prior to the expiry of a Regulated Generating Unit’s base life should not have the effect of increasing the RGUCC charge to the Regulated Generating Units that remain in service? If not, please explain.

(b) Please provide the derivation of the Regulated Generating Unit revenue offset of $21,391,479 shown in Schedule 5.2.

(c) Please provide the derivation of the 70,395.6 MW/months billing determinant as shown in Schedule 5.9.

Response:

(a) Yes, the AESO agrees. RGUCC charges over time were in effect established in EUB Decision 2000-1 dated February 2, 2000. The AESO’s calculation of RGUCC charges in accordance with that decision is attached as Schedule BR.AESO-018 (a).

(b) The Regulated Generating Unit revenue offset was calculated by multiplying the RGUCC charge of $303.88/MW per month (prior to rounding) times the forecast 2007 RGU Maximum Continuous Rating (MCR) billing determinant of 70,395.6 MW-months.

(c) The 2007 RGU MCR billing determinant was calculated by summing the MCRs of all Regulated Generating Units forecast to be in service during 2007, times 12 months. The calculation is attached as Schedule BR.AESO-018 (c).