May 25, 2009

TFO O&M Cost Causation Study Working Group Members
AESO Stakeholders

Dear Working Group Member:

Re: Meeting Agenda for TFO O&M Cost Causation Study Working Group

The first meeting of the TFO O&M Cost Causation Study Working Group for the AESO’s 2010 tariff application is scheduled as follows:

<table>
<thead>
<tr>
<th>Time</th>
<th>1:00 to 3:00 PM</th>
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<tbody>
<tr>
<td>Date</td>
<td>Monday, May 25, 2009</td>
</tr>
<tr>
<td>Location</td>
<td>Meeting Room 2506, AESO Office, 330 – 5th Avenue SW, Calgary</td>
</tr>
<tr>
<td>Refreshments</td>
<td>Coffee and juice</td>
</tr>
</tbody>
</table>

This working group includes the following members:
- AltaLink: James Yeo
- ENMAX: Penny Haldane
- EPCOR: Stan Yee
- StatoilHydro: Brian Blattler
- UCA: Rick Cowburn
- AESO: John Martin, David Michaud
- Consultant to AESO: Arnie Reimer

If you intend to participate in the meeting by conference call, are unable to attend the meeting, or will be represented by an alternate, please let me know as soon as possible.

The agenda for the meeting is proposed to include the following items:

1. **Introductions** 1:00 PM
   - Please indicate which stakeholders you represent

2. **Review agenda** 1:10 PM

3. **Review draft working groups terms of reference** 1:15 PM
   - See enclosed document
   - The AESO proposes to revise the first bullet point in section 3 to the following:
     - Each Working Group will generally have a maximum of six to eight members (including AESO employees and consultants). No more than six stakeholder members will generally be on any one Working Group.
   - Identify any concerns with or revisions required to the terms of reference
• Terms of reference will be finalized after initial meetings for all working groups are complete

4  **Background for TFO O&M cost causation study**  
   Please review the enclosed information before the meeting, if possible:
   (a) Directions 4D and 20A on analysis of TFO O&M costs, from pages 23 and 69 respectively in Decision 2005-096 on the AESO’s 2005-2006 General Tariff Application, released on August 28, 2005
   (b) AESO’s responses to Directions 4D and 20A in its 2005-2006 General Tariff Application Refiling, filed on September 27, 2005
   (c) Discussion of TFO operations, maintenance, and administration costs in sections 7 and 8 (pages 54-56) of the 2006 Transmission Cost Causation Update, filed as an appendix to the AESO’s 2007 General Tariff Application on November 3, 2006
   (d) Discussion of TFO operations, maintenance, and administration costs in section 4.3.3 (pages 12-13) of the AESO’s 2007 General Tariff Application, filed on November 3, 2006
   (e) Directions 2, 6, and 18 on analysis of TFO O&M costs, from pages 25, 58-59, and 105-107 respectively in Decision 2007-106 on the AESO’s 2007 General Tariff Application, released on December 21, 2007
   (f) AESO’s responses to Directions 2, 6, and 18 in its 2007 General Tariff Application Refiling, filed on February 1, 2008

5  **Scope of TFO O&M cost causation study**  
   See enclosed draft proposal for study of electric transmission system operating and maintenance costs

6  **Methodology to functionalize TFO O&M costs**  
   What approaches could be used to functionalize TFO O&M costs as bulk system, local system, or point of delivery?

7  **Methodology to classify TFO O&M costs**  
   What approaches could be used to classify TFO costs as demand-related, energy-related, or customer-related?

8  **Follow-up required for next meeting**  
   Summarize what tasks need to be completed before next meeting and who will complete them

9  **Dates and times for next meeting(s)**

10 **Adjourn**

This agenda and all other printed information related to the TFO O&M Cost Causation Study Working Group is available on the AESO's website at www.aeso.ca by following the path Tariff ▶ Current Consultations ▶ 2010 Tariff. The AESO appreciates stakeholders’ participation in this consultation.
If you have any comments or questions on this consultation process or the AESO’s tariff application, please contact me at 403-539-2465 or john.martin@aeso.ca, or David Michaud at 403-539-2471 or david.michaud@aeso.ca.

Sincerely,

[original signed by]

John Martin
Director, Tariff Applications

enclosures

c:  David Michaud, Manager, Regulatory, AESO
    Arnie Reimer, TFO O&M Study, Consultant to AESO
AESO 2010 Tariff Consultation Working Groups
Terms of Reference

1 Purpose

The AESO 2010 Tariff Consultation Working Groups will be forums for stakeholders to provide perspective, advice, and expertise to the AESO on specific topics for the AESO’s 2010 tariff application. The Working Groups are intended to augment the internal capabilities of the AESO and support effective consultation by engaging stakeholders in the development of the tariff application.

2 Topics

Working Groups are proposed to examine the following topics for the AESO’s 2010 tariff application. Some issues are suggested for exploration within each topic, although each Working Group is expected to determine what issues should be examined for each topic.

(a) POD Cost Function and Investment Level Update
   • Substations included in POD cost data set
   • Inflation index to escalate POD cost data to 2010
   • Multiplier to determine investment level

(b) TFO O&M Cost Causation Study
   • Respond to AUC directions on analysis of TFO O&M costs
   • Determine if TFO O&M costs are energy-related
   • Determine if TFO O&M costs should be functionalized similarly to capital costs

(c) DTS Operating Reserve Charge Design
   • Methodology to analyze and assess design of operating reserve charge
   • Criteria for selection of appropriate design for operating reserve charge

(d) Fort Nelson Rate FTS
   • Rate design principles for Fort Nelson and similar services
   • Cost allocation approaches between BC and Alberta loads in the Rainbow Area
   • Contractual considerations for Fort Nelson and similar services

(e) Export and Import Rates XTS and ITS
   • Rate design principles for higher-priority export and import services
   • Similarities and differences between domestic and intertie services
   • Potential allocation of “deep system” costs to services over merchant interties

(f) Deferral Account Riders B and C
   • Rate design principles for deferral account riders
   • Practicality of improving allocation accuracy of deferral account riders
   • Possible integration of Riders B and C
(g) **Tariff Changes Related to Transition of Authoritative Documents (TOAD)**
- Provisions that could be moved from tariff to other authoritative documents (such as technical standards or ISO Rules)
- Common provisions that could be standardized and consolidated
- Dispersed information that could be consolidated

(h) **Amortized Customer Contribution Option and Other Contribution Provisions**
- Potential changes to AESO standard facilities definition
- Potential provisions for amortized customer contribution option
- Assessment of credit-worthiness and mitigation of risk of default

(i) **Tariff Provisions Related to Customer-Owned Substations**
- Principles for tariff provisions at customer-owned substations
- Assessment of Primary Service Credit and associated investment factor
- Application of substation fraction at customer-owned substations

3 Working Group Members

The Working Groups will consist of AESO stakeholders and AESO employees with interest, expertise, or both in the specific topic being examined in each Working Group.
- Each Working Group will have a maximum of four to six members (including AESO employees). No more than four stakeholder members will be on any one Working Group.
- Stakeholder involvement in a Working Group is voluntary. Membership will generally be on a first come, first served basis.
- Stakeholders may coordinate involvement in different Working Groups among themselves to avoid duplication and overlap of interest.
- The AESO may suggest changes to the composition of individual Working Groups to ensure diversity and balanced representation of views.

4 Duration

Each Working Group will be active from May 1, 2009 to no later than mid-July 2009.
- A Working Group may conclude activities earlier if no further review of the topic would be helpful to the AESO's 2010 tariff application.
- A Working Group may also continue activities for a longer period if an extension is required to effectively satisfy its purpose.

5 Scope and Duties

Working Groups will review and discuss options and alternatives for proposals being considered for inclusion in the AESO's 2010 tariff application. Working Groups are not decision-making bodies. Consultation within Working Groups will not replace general stakeholder consultation. The AESO will consider consultation within the Working Groups in the context of its broader stakeholder consultation.
(a) Working Groups will determine their own meeting dates and times. Meetings are expected to occur about every two weeks, for one to two hours. Meeting agendas will be prepared and communicated in advance as much as practical. Members may participate in meetings via conference call. A Working Group will generally be coordinated and chaired by an AESO employee. Meetings may be held at the office of the AESO or of other Working Group participants.

(b) Working Group members are expected to dedicate appropriate time to actively participate in Working Group meetings, to review material prior to meetings, and to address questions raised and issues identified following the meetings. Working Group members may assign work to others within their organizations with appropriate technical or regulatory expertise on the topic.

(c) Working Group members are expected to engage in informal open discussion on a “without prejudice” basis. Although discussion in Working Groups will not be presented as evidence in the AESO’s tariff application proceeding, the AESO and participants may refer in their respective evidence to any conclusions they reach as a result of Working Group discussion. A participant or representative on any Working Group will not be precluded from participating in the AESO’s tariff application proceeding before the AUC. Neither stakeholders nor the AESO will be limited in any way from expressing views that may differ from those expressed in the Working Group. However, all participants are expected to engage in meaningful and transparent dialogue in the Working Groups.

(d) The activities of the Working Groups and related written documents will be communicated to stakeholders through postings on the AESO website, as appropriate. However, minutes of discussion and transcripts of conversations will not generally be prepared. All material will be assumed to be non-confidential unless identified otherwise. All such material will be available on the AESO website at www.aeso.ca by following the path Tariff ▶ Current Consultations ▶ 2010 Tariff. All stakeholders will generally have opportunity to comment on the material posted, as part of comment processes in the AESO’s general stakeholder consultation.

(e) Working Group conclusions will be considered by the AESO in developing proposals for its 2010 tariff application. The AESO’s 2010 tariff application will reflect decisions consistent with legislation, policy, and the AESO’s mandate, considering the input and advice provided by the Working Groups. The rationale for the AESO’s proposals will be included in the tariff application.

6 Deliverables

The AESO 2010 Tariff Consultation Working Groups will provide the following.

(a) Advice and expert comments on specific topics being considered as part of the AESO’s 2010 tariff application.

(b) Suggestions to improve the studies, analysis, rates, and terms and conditions that will comprise the AESO’s 2010 tariff application.
(c) Identification of legislation, policy, prior regulatory decisions, principles, precedent, and practices that are relevant to the topic being examined by the Working Group.

7 Principles

The activities of the AESO 2010 Tariff Consultation Working Groups will be consistent with the AESO’s mandate to prepare a tariff that is just and reasonable, and that is not unduly preferential, arbitrarily or unjustly discriminatory, or inconsistent with or in contravention of any applicable law.

Working Groups will consider topics in the context of an overall Alberta perspective that will improve the fairness, efficiency, clarity, and consistency of the AESO’s tariff.

8 Expenses

Working Group members are responsible for their own out-of-pocket expenses and time for participating in Working Group activities. The AESO will not reimburse participants for costs incurred due to involvement on a Working Group.

9 Recent AESO Tariff Decisions

Members of the Working Groups should, at a minimum, be familiar with discussion of the topic in recent AESO tariff decisions, which are listed below for convenience.

- EUB Decision 2005-132: AESO Review and Variation of Customer Related POD Charge (released on December 6, 2005)
The nature of a transmission facility is such that the facility is sized to meet the forecast demand, and a conductor optimization study is typically performed to determine the optimum conductor size to optimize losses. (p. 36)

The cost of a substation was assessed with a normal efficiency transformer, and a high efficiency transformer that may be suitable for a high load factor customer. (p. 43)

These excerpts indicate that planners do study the efficient expansion of the transmission system, and that there are capital costs associated with energy efficiency in both conductors and transformers. However, Mr. Reimer described (T0834) the difficulty in recreating history to determine precisely what embedded costs would have been associated with energy efficiency. Given these challenges, a simplified approach was taken in the Transmission Cost Causation Study to assess costs associated with energy efficiency. The AESO submits that costs are incurred to optimize losses on the transmission system…

Parties also questioned the use of CLMS to moderate the demand charge otherwise called for. With respect to this matter, the Board notes that the TCCS appears to have studied only two of many bulk lines in its analysis. IPCAA has argued that one of the two lines studied, the Edmonton-Calgary line, had significant loading caused by opportunity service at the time of CLMS. Indeed, the Board observes that Mr. Reimer, as referenced above, has acknowledged that CLMS may be expected to be more coincident with system peak. As such, the discount that Mr. Reimer proposes in demand related charges may not be fully justified. The Board expects that, in future studies, the AESO will conduct a more thorough review of all those lines comprising the bulk system. This should give a more accurate indication as to the exact portion of costs that are energy related.

However, the Board also considers that a reasonable portion of TFO costs are related to O&M and that a material percentage of these may be energy related. Unfortunately, the impact of this factor does not appear to have been researched in this current study and therefore the Board cannot draw a firm conclusion respecting its impacts on the demand charge. Nonetheless, based upon the percentage that O&M expenses comprise of a TFO’s revenue requirement,37 the Board considers that such an analysis would support a reasonable classification of costs as energy related. The Board expects the AESO to address these issues in future cost of service studies.

The Board also notes the following from the TCCS.38

While transmission planning models consider one point in time, transmission planning criteria are based on experience and judgment to ensure reliable operations year round, and planners will optimize conductor size in order to minimize the total cost of wires and losses. The transmission planning process is often used as justification for classification of all wires costs by demand, because transmission planners consider demand under various scenarios. In the event that transmission planning criteria are violated, the transmission system is upgraded to accommodate the forecast demand. However, transmission planning criteria are based on experience and judgment, and therefore, it is too simplistic to classify transmission costs as completely demand related.

37 AltaLink 2004-2007 GTA Application
38 TCCS, page 34
charge only to the deemed “optional facility costs” of a new interconnection, the AESO appears to be implicitly assuming that the combined amount of the pre-paid O&M costs associated with the “non-optional” local interconnection facilities and the cost of the non-optional facilities themselves will fall below the level permitted under the maximum investment allowance. However, the Board considers that this should not be presumed, particularly in light of the adjustments to the maximum investment function ordered by the Board in Section 6.1.4 above.

While the Board considers that the prepaid O&M charge may be improved with further research, the Board considers that the adoption of a 12% surcharge as proposed by the AESO is a good starting point for the purposes of the 2006 Tariff.

Accordingly, the Board directs the AESO in its refiling Application to apply the 12% prepaid O&M surcharge such that:

- The surcharge will be determined separately for the optional and non-optional facilities;
- The portion of a DTS interconnection project’s prepaid O&M surcharge based on cost of the optional facilities will be fully charged out to the interconnecting DTS customer, consistent with the Board’s disposition of other optional facility costs; and,
- The portion of the prepaid O&M surcharge related to non-optional facilities is added to other non-optional facility costs and evaluated against the maximum investment function to determine the amount of customer contribution that may be required in respect of the standard facility portion, if any.

While the Board believes that the adoption of a 12% prepaid O&M surcharge is directionally appropriate and should be applied for the purposes of the 2006 tariff, the Board is not convinced that sufficient evidence has been gathered to determine that 12% figure appropriately tracks costs. Accordingly, the Board directs the AESO to conduct further analysis of the appropriate amount of the prepaid O&M surcharge and to reflect their findings in the design of the surcharge included no later than with the AESO’s 2008 General Tariff Application.

### 6.2 Generator System Contribution

Subsection 17(2) of the *Transmission Regulation* requires the AESO to collect, in its tariff, a system contribution charge of $10,000/MW from the owners of new generators for system upgrades to existing transmission facilities required as a result of a generator’s entry on to the AIES grid. This subsection further directs the AESO to collect a system contribution charge of no more than $40,000/MW from the owners of new generators who locate in areas of the transmission system where generation exceeds load, with the amount to be based on the location of the new generating unit relative to the load.

Subsection 17(4) of the *Transmission Regulation* directs the AESO to include in its tariff, a provision for the refund to the owner of a generating unit who paid system contribution charges pursuant to Section 17. The refund must be received over a period of 10 years from the date it was paid unless the operation of the generating unit failed to meet satisfactory performance standards as set forth in rules to be developed by the AESO pursuant to Subsection 17(5).

In its application, the AESO proposed to refund generator system contributions by way of 9 equal payments spread out over the 10 year period. The AESO explained that its suggested proposal was created to allow for the event that an owner of a generator might experience...
Direction
However, the Board also considers that a reasonable portion of TFO costs are related to O&M and that a material percentage of these may be energy related. Unfortunately, the impact of this factor does not appear to have been researched in this current study and therefore the Board cannot draw a firm conclusion respecting its impacts on the demand charge. Nonetheless, based upon the percentage that O&M expenses comprise of a TFO’s revenue requirement, the Board considers that such an analysis would support a reasonable classification of costs as energy related. The Board expects the AESO to address these issues in future cost of service studies. [p. 23]

Response
The AESO will include the directed analysis in a future cost causation study of the transmission system.
20A  Conduct Further Analysis on Appropriate Prepaid O&M Rate  Page 1 of 1

Direction
While the Board believes that the adoption of a 12% prepaid O&M surcharge is directionally appropriate and should be applied for the purposes of the 2006 tariff, the Board is not convinced that sufficient evidence has been gathered to determine that 12% figure appropriately tracks costs. Accordingly, the Board directs the AESO to conduct further analysis of the appropriate amount of the prepaid O&M surcharge and to reflect their findings in the design of the surcharge included no later than with the AESO’s 2008 General Tariff Application. [p. 69]

Response
The AESO will reflect further analysis in the design of an appropriate prepaid operations and maintenance surcharge no later than its 2008 GTA.
7. OPERATIONS, MAINTENANCE AND ADMINISTRATION

The TCCS study was based on the assumption that OM&A costs were proportional to property. This assumption was made because OM&A costs are a small part of the total revenue requirement, and additional data was unavailable. OM&A accounts for approximately 25% to 33% of the total revenue requirement for a TFO.

One concern of interveners is that some facilities are older than others, and that OM&A should be studied to reflect the vintages that exist. A high level review of depreciation studies shows that substation facilities and transmission facilities have a similar remaining composite life. Based on similar remaining composite lives, it is not apparent that some facilities would have significantly different levels of OM&A costs associated with their operation.

TFO GTA’s contain some information regarding the components of OM&A but this information is insufficient to functionalize OM&A costs in alignment with the functional definitions in use in the TCCS Study. Additional study would be required to determine the OM&A of facilities as they age. Conventional wisdom indicates that OM&A costs increase as facilities age and this relationship for facilities in Alberta must be understood to properly functionalize these costs.

The OM&A costs were not studied because work was focused in other areas such as classification of Bulk System costs. A study of OM&A costs must ensure that functionalization of OM&A costs is aligned with the functions in the cost study, and that the current distinction between Local System and POD system may change.

OM&A costs may vary by vintage, whereby old facilities require more funds to maintain than do newer facilities. OM&A costs may also vary by equipment type, whereby substation equipment requires a different types of
maintenance than do transmission lines (vegetation management is required for lines while switch gear maintenance applies only to substations).

The breakdown of AltaLink and Atco Electric TFO facilities show that each function has a different make up of equipment type as follows:

Table 6 Transmission Facility Type by Function

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<thead>
<tr>
<th></th>
<th>Bulk</th>
<th>Local</th>
<th>POD</th>
</tr>
</thead>
<tbody>
<tr>
<td>Substation</td>
<td>43.6%</td>
<td>10.8%</td>
<td>90.9%</td>
</tr>
<tr>
<td>Line</td>
<td>53.4%</td>
<td>86.6%</td>
<td>5.8%</td>
</tr>
<tr>
<td>General</td>
<td>3.0%</td>
<td>2.5%</td>
<td>3.3%</td>
</tr>
<tr>
<td>Total</td>
<td>100.0%</td>
<td>100.0%</td>
<td>100.0%</td>
</tr>
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The relative age of equipment is estimated by dividing the accumulated depreciation by the property, plant and equipment amount. The AltaLink data for 2003 shows that both transmission lines and substations have accumulated depreciation of between 50% and 60%, indicating that the relative ages are similar.

Table 7 Depreciation of Transmission Facilities

<table>
<thead>
<tr>
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<th>2003 PPE</th>
<th>2003 Acc Dep</th>
<th>Acc Dep % of PPE</th>
</tr>
</thead>
<tbody>
<tr>
<td>Substations</td>
<td>659.7</td>
<td>343.5</td>
<td>52.1%</td>
</tr>
<tr>
<td>Lines</td>
<td>657.3</td>
<td>388.4</td>
<td>59.1%</td>
</tr>
</tbody>
</table>

At this time, there is insufficient data to properly allocate OM&A costs by function, vintage or equipment type.

The impact of functionalizing OM&A is likely to be small because:

- OM&A accounts for about ¼ of the revenue requirement,
- Difference in OM&A accounting for equipment age is likely to be small because all equipment is similarly aged,
- Difference in OM&A accounting for difference between substations and lines is likely to be small since the largest function (Bulk System) is relatively equally split by line and substation equipment.
8. RECOMMENDED ADDITIONAL ACTIVITIES

Local System and POD

Further study regarding the distinction between Local System and POD should be completed following the review of the Customer Contribution Policy.

The TCCS study proposed a distinction between Local System and POD that aligns with the concept of common facilities (useful to more than one point of delivery) and dedicated facilities (dedicated to one point of delivery). The Customer Contribution Policy uses different distinctions.

If definitions are refined, the TCCS should be reviewed and updated. This updated study would provide a new basis for the fixed and demand related costs associated with POD’s.

OM&A

A new study of OM&A should be conducted to facilitate the functionalization of OM&A. The relationship between age and OM&A should be studied as well as the relationship between OM&A and equipment type. This study would provide for an improvement in the functionalization of approximately ¼ of the transmission revenue requirement.

The data required for such a study is not currently available. The development and compilation of this data would require a considerable effort and would require details of O&M expenditures by facility and by equipment type over the life cycle of transmission and substation equipment. Since OM&A accounts for a small portion of the total revenue requirement, better functionalization of OM&A may not change the results of the TCCS study significantly.
Some parties suggested costs of the bulk system be recovered based on the coincidence of loads in a region with bulk line loading in the region. The AESO does not consider a regional cost analysis permissible under the Electric Utilities Act, which requires the AESO to recover costs on a “postage stamp” basis for all customers.

The AESO also does not consider it appropriate to recover bulk system costs wholly on an energy basis. An energy ($/MWh) charge indicates that total throughput on the bulk system is the most important cost consideration. This is clearly not the cost driver for the bulk system; individual bulk lines and other equipment are designed to meet maximum demand requirement, not total throughput.

The billing determinant which appropriately recognizes that demand in every hour is important is non-coincident peak (NCP) demand, defined as highest metered demand in the AESO’s DTS rate. NCP cost recovery signals that demand in any interval during the billing period could cause costs on the bulk system. Similarly, since there are no distinct monthly usage patterns on the bulk system, demand in any month could cause costs on the bulk system. The AESO therefore considers it appropriate to incorporate a demand ratchet in the bulk system billing determinant. Finally, to the extent that the bulk system is planned to meet future loads on the system as indicated in part by customers’ contracted capacity, the AESO considers that bulk system billing should include a contract capacity component.

Highest metered demand, demand ratchet, and contract capacity constitute the billing capacity used for the demand component of the local system and POD charges in the current DTS rate. The AESO proposes that billing capacity also is an appropriate billing determinant for the recovery of bulk system costs. The billing capacity determination is proposed to remain the same as in the current DTS rate; that is, it is 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.

The specific moderation of the demand charge questioned in Direction 4C is addressed in section 4.5.1 of this application, which discusses the design of the system charge in the DTS rate.

4.3.3 Operations, Maintenance, and Administration Costs

In responding to Direction 4D of Decision 2005-096, PS Technologies reviewed the functionalization and classification of operations, maintenance, and administration (OMA) costs within the Transmission Cost Causation Study. The Update considered that OMA costs could vary by equipment vintage and type, but noted that data was not available to refine the functionalization and classification of OMA costs. 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. No changes to the
transmission cost functionalization and classification were recommended as a result of the review of OMA costs.

4.3.4 Transmission Point of Delivery Cost Classification

The *Transmission Cost Causation Update* examined the classification of point of delivery costs, defined to include substations providing service to load customer and radial lines, if any, associated with such substations. The original *Transmission Cost Causation Study* included a zero intercept analysis to classify 56.2% of point of delivery costs as customer-related costs, and a minimum system analysis to classify the remaining costs 43.1% as demand-related and 0.7% usage-related. However, the data relied upon for the analysis exhibited significant scatter that could not be examined in detail using historical transmission facility information.

While discussing the AESO’s maximum investment formula in Decision 2005-096, the EUB determined “that cost...is the appropriate starting point for establishing the investment policy.” (p. 56) The EUB ultimately directed and approved an investment policy derived from the point of delivery cost information included in the *Transmission Cost Causation Study*. However, in Direction 13A the EUB also required the AESO to analyze additional data to recommend a maximum investment function, as provided in section 6 of this Application.

The same costs (essentially those comprising the point of delivery function) ultimately underlie both the DTS POD charge and the AESO investment function. The AESO therefore developed both aspects of its tariff together, and relied primarily on the detailed examination of the point of delivery cost data conducted during development of the maximum investment function.

Analysis of point of delivery cost data in the *Customer Contribution Study* (as also discussed in section 6) found that those costs can be reasonably represented by the following cost function:

\[
\text{Point of Delivery Costs} = 0.947 \text{ million} + (0.621 \text{ million/MW} \times \text{first 7.5 MW of DTS Capacity}) + (0.154 \text{ million/MW} \times \text{DTS Capacity above 7.5 MW})
\]

This cost function is primarily based on detailed examination of 30 projects representing a total DTS capacity of 516.7 MW and total project costs of $213.2 million, and utilizes a linear regression analysis to determine an average cost function.

However, the projects in the data set did not include any interconnections with DTS capacities less than 7.5 MW. To determine a cost function for such smaller projects, the AESO adapted a minimum-intercept method using a small subset of POD cost information included in the *Transmission Cost Causation Study*. The minimum-intercept approach relates installed cost to capacity by creating a curve for various capacities using regression techniques and then extending the curve to a no-load intercept. This was the approach used to establish the fixed and first 7.5 MW components in the point of delivery cost function provided above.
Table 1. 2006 Functionalized and Classified Wires Costs ("Updated" % of Total)

<table>
<thead>
<tr>
<th>Classification</th>
<th>Total</th>
<th>Demand</th>
<th>Usage</th>
<th>Customer</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bulk System</td>
<td>41.7%</td>
<td>34.0%</td>
<td>7.7%</td>
<td>-</td>
</tr>
<tr>
<td>Local System</td>
<td>17.4%</td>
<td>14.3%</td>
<td>3.0%</td>
<td>-</td>
</tr>
<tr>
<td>POD</td>
<td>40.9%</td>
<td>17.6%</td>
<td>0.3%</td>
<td>23.0%</td>
</tr>
<tr>
<td>Total</td>
<td>100.0%</td>
<td>66.0%</td>
<td>11.0%</td>
<td>23.0%</td>
</tr>
</tbody>
</table>

Source: Application Table 4.3.4 (Application Section 4.3.1, p. 8) – totals may not add due to rounding.

The smallest change was a reduction in bulk wires costs classified as usage related, while the largest change was an increase in total POD costs by 1%.

The TCCU also suggested potential future functionalization refinements for future cost causation updates, particularly regarding the distinction between local system and POD as well as the relationship of OM&A to age and equipment type. In the case of the OM&A study, PS Technologies suggested that due to the small proportion of total TFO revenue requirement that is comprised of OM&A costs, modifying the functionalization of these costs may not have much impact on the TCCU results.

The Board considers that the TCCU represents the appropriate cost of service starting point. The AESO, working in conjunction with its stakeholders, has performed additional studies and implemented the results of these studies in improving the TCCS approved for use by the Board in Decision 2005-096. The Board approves the functionalization percentages contained in Table 4.3.4 of the Application as filed.

The Board directs the AESO to compare the value of the additional TCCU refinement recommendations proposed by PS Technologies against the cost of performing the additional research, present the results in its next GTA, and to propose at its next GTA any refinements it considers warranted.

5.3.2 Functionalization (Proposed Re-Bundling) of Local and Bulk Wires Costs

As discussed above, the TCCU subfunctionalized the transmission assets into bulk wires, local wires and POD assets.\(^{69}\)

In Decision 2005-096, the Board directed the AESO to unbundle the bulk and local wires costs for purposes of DTS rate design. At that time the Board considered that an unbundled rate design would allow for a rate more reflective of cost causation and send more appropriate price signals to customers.\(^{70}\)

As a result of the analysis conducted in the TCCU and in Appendix D to the Application the AESO accepted the hypothesis that peak load did not correlate to maximum stress on the system and that it was load in all hours that mattered. The AESO has therefore proposed that bulk wires and local wires be classified and allocated on the same basis – that is with a demand component allocated on the basis of non-coincident peak (NCP) with a billing capacity ratchet and an energy component collected on the basis of all hours usage. In the AESO’s view, this provides a rate

\(^{69}\) Ex. 012, TCCU, p. 52

\(^{70}\) Decision 2005-096, p. 26
Submissions on various considerations relating to radial as compared to looped lines within the POD cost function were also received from the AESO and DUC. These submissions, and the reply argument of CCA/PICA primarily addressed:

- the need to consider the tendency of radial lines interconnections to become looped over time;
- the impact of radial lines on the proportion of POD costs that should be considered fixed rather than variable with POD capacity;
- whether a double count occurs as a result of the inclusion of the costs of looped lines in the POD cost function;
- whether the proposals of CCA/PICA adequately reflected the impact of economies of scale on POD costs.

The adjustment proposed by CCA/PICA to the POD cost function for the POD charge was to reflect both the tendency of radial lines to become looped over time and the findings of PS Technologies that only 34% of lines are connected to radial lines.

However, the Board considers the observation that 34% of PODs are connected to radial lines to be primarily, if not exclusively, a TFO cost functionalization issue. It is not a concern in respect of the allocation of functionalized POD costs for determining the POD charge.

Given that in the context of the POD charge, the POD cost function is used to allocate POD related costs among DTS customers of various sizes, the Board does not consider it to be necessary or appropriate to modify the POD cost function or the POD charge unless it can be demonstrated that there is a greater tendency for smaller or larger PODs to be connected radially rather than to the looped system. However, the reply submission of CCA/PICA acknowledges that radial lines costs are essentially fixed and unrelated to the size of the POD. CCA/PICA clarified in their reply that the lower allocation of radial line costs to smaller customers had been proposed primarily to provide rate relief to such customers. The Board has previously found that stability and predictability of rates is afforded secondary consideration. This is a separate issue from the POD cost function for the purposes of the POD charge. Any rate shock that arises from the Board’s findings, including changes to the POD charges, is addressed in section 5.9 of the Decision.

Given the foregoing, the adjustment to the POD charge cost function proposed by CCA/PICA is denied.

5.7.8.3 Treatment of TFO O&M Costs in POD Cost Function

PPGA submitted in its evidence that the AESO had provided no evidence, facts or analysis to support its assertion that O&M costs follow capital costs. Given this, PPGA submitted that the AESO’s proposed POD charge does not reflect true cost causation. PPGA questioned the validity of the AESO’s entire POD charge rate proposal.

PPGA argued that even thought TFO O&M costs are in the range of $130-$150 million, the AESO had simply asserted that the impact of O&M costs on the POD cost function would be small.
The AESO argued that the classification and functionalization of transmission wires costs resulting from the TCCU was generally accepted by participants in this proceeding, other than PPGA. The AESO noted that Decision 2005-096 had set out two directions respecting cost classification, including a direction that the AESO analyze the functionalization and classification of O&M costs.

The AESO noted that that PS Technologies’ analysis of O&M costs found that data was not available to allow refinement of the functionalization and classification of OMA costs to reflect the impact of equipment vintage and type. In any event, the TCCU expected the impact on total cost functionalization and classification to be small because O&M costs account for about one-quarter to one-third of TFO revenue requirements. The AESO further noted that PS Technologies had not recommended any changes to transmission cost functionalization or classification as a result of its review of O&M costs for the TCCU.

Although the PPGA took issue with the AESO for not having conducted research in support of its assertion that TFO O&M costs vary with POD capital costs, the PPGA provided no evidence indicating that TFO O&M costs do not vary with the level of POD capital costs. The PPGA also did not provide evidence of whether the AESO’s proposed POD cost function would understate or overstate the causation of TFO O&M costs.

In the absence of more specific information, the Board is not prepared to direct the AESO to make additional adjustments to the POD cost function or the resulting POD charge component of Rate DTS for the purposes of the 2007 tariff. However, so long as it can be accomplished at a reasonable cost, the Board considers that additional study into the causation of TFO O&M costs may be of value for future AESO rate design purposes as well as for the purposes of understanding TFO O&M forecasts within the context of future TFO GTAs. Accordingly, the Board directs the AESO to indicate in its refiling application the cost and time required to prepare a further study into the causation of TFO O&M costs.

5.8 DTS Rate Summary

As noted in the introduction to this section the AESO has proposed a number of significant changes to the structure of the DTS rate. The Board considers that it may be helpful to readers to provide a summary of its findings and directions with respect to the DTS Rate.

In support of its Application, the AESO supplied the 2006 TCCU, an update to the TCCS of 2005. The TCCU updated the functionalization of transmission assets provided in the TCCS, and subsequently approved by the Board in Decision 2005-096. The functionalization provided in the TCCU regarding bulk wires costs, local wires costs and POD costs showed little, if any, change from the TCCS and it has been approved by the Board in this Decision.

With respect to classification of bulk and local wires costs, the bulk of the TCCU was devoted to advancing the hypothesis that load in all hours is more important to cost causation than peak loads that occur over a few hours during the course of the year. The AESO further supported this hypothesis in Appendix D to the Application. Given this evidence, the AESO proposed to bundle both bulk and local wires costs, to classify approximately half of these costs as energy related through the use of the A&E methodology and to collect these costs through an all hours energy

193 Decision 2005-096, p. 23
The Distribution Point-of-Delivery Interconnection Process Guideline - Standards of Service simply summarize the standards that each Disco applies to its distribution system with respect to the allowable voltage fluctuations/flicker.\textsuperscript{342} The Board notes that the standards applied by the Discos are not uniformly consistent.

The Board understands that both of these guidelines were developed by the AESO with the involvement of Discos.\textsuperscript{343}

No evidence was submitted in this proceeding of an AESO requirement that a VFD would be required to accommodate motor starting on the distribution system. Based on the evidence in this proceeding, the Board agrees with the AESO, that flicker limits on the distribution system are within the purview of the Discos. The Board considers that the decision to provide transmission or distribution facilities in the circumstances of specific customers must be evaluated separately for customers of the AESO and customers of Discos. Accordingly, the Board will not direct the AESO to amend the interconnection process guidelines. In general, to the extent that PPGA, any specific member thereof, or an end use customer of a Disco, has concerns with technical standards established by a Disco, those concerns should be addressed directly with the Disco and if any irresolvable concerns remain they may be pursued in a relevant Board proceeding relating to the relevant Disco.

8.3 Prepaid O&M Charge

In the Application, the AESO described its proposed changes to Article 9.4 of its T&Cs.\textsuperscript{344} The AESO noted that although the Board had determined in Decision 2005-096 that a charge based on 12% of the cost of the both standard and optional facilities for a customer interconnection, the AESO proposed to amend the prepaid O&M charge to reflect only the cost of any optional facilities built for a new customer interconnection.

The AESO noted that a proposal in the AESO’s prior GTA to apply a prepaid O&M charge only on the optional portion of an interconnection project was rejected by the Board in Decision 2005-096. However, the AESO suggested that the Board’s prior decision should be reconsidered because the Board’s rationale for varying the AESO’s original proposal in Decision 2005-096 did not take into account the impact of the ongoing re-assessment of the maximum investment function caused by applying the “80/20” rule.\textsuperscript{345}

The AESO also expressed concerns that applying a prepaid O&M charge on standard facilities would require new procedures and processes to ensure O&M costs are being recovered correctly and are not recovered in other components of the TFOs revenue requirement. In addition, the AESO expressed concerns that applying a prepaid O&M charge to standard facilities could compromise harmonization efforts between the AESO and the Discos, since Discos include an O&M charge only on optional facilities. The AESO also submitted that its proposal would be beneficial because it would avoid intergenerational inequity, reduce tariff complexity and would

\textsuperscript{342} Ex. 098, AESO AE-3, AESO Distribution Point-of-Delivery Interconnection Process Guideline - Standards of Service, section 4.3, pages 37-39
\textsuperscript{343} Ex. 098, AESO AE-3, pages 2-3 of 4; Tr 847
\textsuperscript{344} Ex. 007, Application Section 6.5.2, pp. 13-15
\textsuperscript{345} Ex. 007, p. 14 of 47
respond to the concerns of stakeholders who had opposed the charge during stakeholder consultations.

The AESO argued that applying an O&M charge for facilities in excess of standard would send an appropriate price signal to customers that their postage stamp rate reflects only costs associated with the standard level of service provided by the AESO. The AESO noted that because O&M costs associated with standard service are properly recovered through average rates, it is not necessary to include an O&M amount as part of the customer related cost of standard facilities used to determine the contribution.

TCE indicated in its argument that it was in agreement with the AESO’s proposed treatment of prepaid O&M.

The Board reiterates that it considers that it is appropriate to send economic signals to AESO customers that appropriately reflect the cost causation consequences of a customer’s decisions.

No evidence was filed indicating that additions of new customer PODs or expansions to existing PODs do not generate some level of incremental TFO O&M costs above and beyond the incremental capital costs of new interconnection facilities. In the absence of such evidence, the Board considers that projected incremental TFO O&M costs should be reflected in the AESO’s customer contribution policy.

While the Board agrees with the AESO that a signal reflecting incremental TFO O&M costs should be provided to customers seeking new or expanded interconnections, the Board does not agree with the AESO’s proposal to provide this signal only in respect of the “optional” portion of an interconnection project. To the extent that the incremental capital costs of a new interconnection are at least proportionally related to incremental TFO O&M costs, it would be inappropriate to effectively confine this relationship to the optional portion of facility capital costs. If TFO O&M costs are related to facility capital costs, it does not follow that an estimate of incremental TFO O&M costs for the purpose of the economic signal should be generated only by the optional component of capital cost.

It also follows that at the time an estimate of the incremental TFO O&M costs is provided, any amount of the incremental TFO O&M costs deemed to be related to the optional portion of the new interconnections should be borne entirely by the interconnecting customer. This is the effect of Article 9.4 as currently approved. Furthermore, the Board considers that the estimated increment of TFO O&M cost related to constructing standard facilities should be evaluated against the maximum investment allowance established by the Board. Again, this treatment is accommodated in the currently approved wording of Article 9.4. As discussed in section 8.1.2.2, the maximum investment allowances approved in this Decision are larger than those approved in Decision 2005-096.

Direction 20A instructed the AESO to conduct a study of incremental TFO O&M to be included in the AESO’s 2008 GTA. However, as the AESO did not advance the completion of this direction in the Application, as it did with other aspects of the customer contribution policy (such as the AESO’s advancement of the cost study used in support of the AESO’s revised maximum investment function), the Board does not have any basis at this time to revise its finding in Decision 2005-096 that, on average, $0.12 of incremental TFO O&M costs will be generated by each $1.00 of capital investment in an interconnection facility. However, additional research into
the relationship between incremental TFO O&M costs and POD capital costs remains valuable. Accordingly, the Board directs the AESO to respond to Direction 20A from Decision 2005-096 in its next GTA.

In light of the above, the Board finds that the wording of Article 9.4 as approved in Order U2005-464 remains for the most part appropriate. However, to avoid potential confusion arising from the use of the word “prepaid”, the Board directs the AESO to amend Article 9.4 as indicated below, and to include this revised wording for Article 9.4 in updated T&Cs to be provided with the AESO’s filing application:

9.4 Operations and Maintenance
For customers taking service under Rate DTS, an operations and maintenance charge of 12% will be added separately to the costs of:
(a) AESO Standard Facilities required to provide service to the customer where these costs are eligible for Local Investment determined in accordance with Article 9.6; and
(b) facilities which exceed the AESO Standard Facilities required to provide service to the Customer.

8.4 Staged Contracts and Payments of Related Contributions
In the Application the AESO proposed to amend section 9.7 of the T&C to provide that when a customer requests an increase in contract capacity which requires the construction of new transmission facilities, the approved tariff at the time of project commitment for the new contract capacity request is to be used to determine the customer contribution and contract term. The AESO submitted that these constitute new commercial decisions which therefore required a new commercial arrangement. It considered that in such circumstances, the customer contribution calculation in the tariff in place at the time of the request for additional capacity should be applied. While parties did not question this proposed amendment, they did question the AESO’s policy of collecting a customer contribution at the signing of the original request for service for all future staged loads.

In argument TCE stated that the AESO currently requires a generator to pay the entire cost of the customer contribution for an interconnection close to when a request is initially made and sometimes well ahead of when the costs are actually incurred.346 TCE argued that this may discourage construction of additional generation in Alberta. TCE noted that when questioned by the Board about the need to receive a full customer contribution, where millions of dollars can be required years in advance, the AESO provided what appeared to be two reasons: financial security347 and a demonstration of commitment.348 TCE believed that each of these concerns could easily be dealt with through financial assurances and appropriate agreements. Alternatively, TCE submitted that contributions should be placed in an account (incurring interest) and drawn down as the project proceeds.

EPCOR argued that staged contribution payments will provide a sharper and more precise economic signal. It argued that this would conform to one of the purposes of the EUA, which is

346 Tr. Vol. 2, p. 348, line 18 to p. 349, line 2, p. 360, line 20 to p. 367, line 1
347 Tr. Vol. 4, p. 861, line 13
348 Tr. Vol. 4, p. 864, lines 2-9
Propose Additional Cost Causation Refinements if Warranted

Direction
The Board directs the AESO to compare the value of the additional TCCU refinement recommendations proposed by PS Technologies against the cost of performing the additional research, present the results in its next GTA, and to propose at its next GTA any refinements it considers warranted. [p. 25]

Response
The AESO will present, in its next GTA, a comparison of the value and cost of additional refinements to the transmission cost causation study, and will propose any refinements that it considers warranted at that time. As suggested in the AESO’s response to Direction 6 on assessing the cost and time to study TFO O&M cost causation, it may be efficient to respond to Direction 2 as part of the study required by Direction 6.
Direction
In the absence of more specific information, the Board is not prepared to direct the AESO to make additional adjustments to the POD cost function or the resulting POD charge component of Rate DTS for the purposes of the 2007 tariff. However, so long as it can be accomplished at a reasonable cost, the Board considers that additional study into the causation of TFO O&M costs may be of value for future AESO rate design purposes as well as for the purposes of understanding TFO O&M forecasts within the context of future TFO GTAs. Accordingly, the Board directs the AESO to indicate in its refiling application the cost and time required to prepare a further study into the causation of TFO O&M costs. [p. 59]

Response
The AESO has reviewed with PS Technologies the cost and time required to prepare a further study into the causation of TFO O&M costs. The AESO estimates that such a study would likely require eight months of calendar time to complete and would be expected to incur on the order of $100,000 in AESO and consultant costs. The study would result in recommendations for the functionalization and classification of TFO O&M costs for use in the AESO's DTS rate design, and would include stakeholder consultation. The estimate does not include time or costs related to any regulatory proceeding in which the study or implementation of its results is reviewed.

The estimate also does not include any costs that may be incurred by a TFO in providing information in support of the study. The AESO expects that the study will require significant amounts of information from the TFOs, beyond what is normally provided to external parties. The AESO requests that the AUC confirm that any unforecast costs incurred by TFOs in providing such information is a recoverable expense for the TFOs, either through direct billing to the AESO or through inclusion in a deferral account.

The AESO also suggests it may be efficient to respond to Directions 2 (to propose additional cost causation refinements if warranted) and 18 (to conduct a study of incremental TFO O&M costs) as part of the study of TFO O&M cost causation.
**Direction**
Direction 20A instructed the AESO to conduct a study of incremental TFO O&M to be included in the AESO’s 2008 GTA. However, as the AESO did not advance the completion of this direction in the Application, as it did with other aspects of the customer contribution policy (such as the AESO’s advancement of the cost study used in support of the AESO’s revised maximum investment function), the Board does not have any basis at this time to revise its finding in Decision 2005-096 that, on average, $0.12 of incremental TFO O&M costs will be generated by each $1.00 of capital investment in an interconnection facility. However, additional research into the relationship between incremental TFO O&M costs and POD capital costs remains valuable. Accordingly, the Board directs the AESO to respond to Direction 20A from Decision 2005-096 in its next GTA. [p. 106]

**Response**
The AESO will respond to Direction 20A from Decision 2005-096 in its next GTA. As suggested in the AESO’s response to Direction 6 on assessing the cost and time to study TFO O&M cost causation, it may be efficient to respond to Direction 18 as part of the study required by Direction 6.
6. In the absence of more specific information, the Board is not prepared to direct the AESO to make additional adjustments to the POD cost function or the resulting POD charge component of Rate DTS for the purposes of the 2007 tariff. However, so long as it can be accomplished at a reasonable cost, the Board considers that additional study into the causation of TFO O&M costs may be of value for future AESO rate design purposes as well as for the purposes of understanding TFO O&M forecasts within the context of future TFO GTAs. Accordingly, the Board directs the AESO to indicate in its refiling application the cost and time required to prepare a further study into the causation of TFO O&M costs............59

Scope:

Produce a report for the AESO that will be part of the next AESO GTA outlining operating and maintenance costs of electric transmission systems. The report will address Directive #6 in the EUB Decision 2007-106. The report will study and provide recommendations for the functionalization and classification of O&M costs for use in AESO’s transmission tariff design.

1. Identify Total Revenue Requirement for four largest TFO’s in Alberta for 2 or 3 historical years, by year:
   a. Breakdown of costs into capital and O&M
   b. Breakdown of O&M costs

2. Study of O&M Costs
   a. Over the service life of the facilities
   b. By the type of facilities
      i. Transmission lines,
      ii. Substations and switching apparatus,
      iii. Transformers,
      iv. Protection and Controls,
      v. Telecommunication,
   c. By type of operation/maintenance,
      i. Predictive, preventative,
      ii. Time, condition, operation based and reliability centered,

3. Develop relationship of:
   a. O&M costs in relation to capital costs
   b. O&M costs in relation to transmission functions
      i. Bulk
      ii. Local,
      iii. POD
c. O&M costs in relation to:
   i. Demand related,
   ii. Energy related,
   iii. Fixed

Schedule and Cost:

The time to complete the study is estimated at six months. Within this period, there will be requests to TFO’s for cost information, and time will be required for response. Following the compilation of data, stakeholder information sessions will be held to update stakeholders as to progress and direction as well as preliminary results. Stakeholders will be afforded an opportunity to provide input.