May 28, 2009

POD Cost Function and Investment Level Update Working Group Members
AESO Stakeholders

Dear Working Group Member:

Re: Meeting Agenda for POD Cost Function and Investment Level Update Working Group

The first meeting of the POD Cost Function and Investment Level Update Working Group for the AESO’s 2010 tariff application is scheduled as follows:

<table>
<thead>
<tr>
<th>Time</th>
<th>9:00 to 10:30 AM</th>
</tr>
</thead>
<tbody>
<tr>
<td>Date</td>
<td>Friday, May 29, 2009</td>
</tr>
<tr>
<td>Location</td>
<td>Meeting Room 2539, AESO Office, 330 – 5th Avenue SW, Calgary</td>
</tr>
<tr>
<td>Refreshments</td>
<td>Coffee, juice, and pastries</td>
</tr>
</tbody>
</table>

This working group includes the following members:
- AltaLink: Dean Fischbach
- DUC: Dale Hildebrand
- ENMAX: Andy Morgans
- IPCAA: Sheldon Fulton
- TransCanada: Vince Kostesky
- UCA: Ed de Palezieux
- AESO: John Martin, Raj Sharma

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. IPCAA has already advised that they are unable to participate in this first meeting.

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

1. **Introductions**
   - Please indicate which stakeholders you represent
   9:00 AM

2. **Review agenda**
   9:10 AM

3. **Review draft working groups terms of reference**
   - See enclosed document originally posted on April 22, 2009
   - The AESO proposes to revise section 3 of the draft terms of reference by updating the first bullet point and adding an additional bullet point, as follows:
– 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.
– A company or association may have only one individual participating in any specific working group meeting, although that individual may be an alternate to the usual representative of that company or association.
• Identify any concerns with or additional revisions to the terms of reference
• Terms of reference will be finalized after initial meetings for all working groups are complete

4 Background for POD cost function and investment level update  9:20 AM
• Please review the enclosed information before the meeting, if possible:
  (a) Discussion of DTS point of delivery (POD) costs and charges in Section 5.7 (pages 36-59) of Decision 2007-106 on the AESO’s 2007 General Tariff Application, released on December 21, 2007
  (b) Discussion of customer contribution policy in Section 8.1 (pages 91-99) of Decision 2007-106 on the AESO’s 2007 General Tariff Application, released on December 21, 2007
• Is there other background that participants consider particularly relevant?

5 2010 POD cost function update discussion paper  9:25 AM
• See enclosed discussion paper and supporting Excel workbook for proposed approach to updating POD cost function
• Review scope and content of discussion paper
• Discuss process to finalize discussion paper, including inviting comments from larger stakeholder audience

6 Inflation index used to escalate historical costs to 2010  9:40 AM
• Please review section 4.2 of the discussion paper
• What criteria are important in determining an appropriate inflation index?
• Are there other ways to address the concerns around volatility and the need for a reliable forecast for the index?

7 Applicability to upgrade projects  10:05 AM
• Please review section 5.5 of the discussion paper
• Are there other considerations for ensuring the POD cost function reasonably reflects costs for upgrade as well as greenfield projects?

8 Follow-up required for next meeting  10:20 AM
• Summarize what tasks need to be completed before next meeting and who will complete them

9 Dates and times for next meeting(s)  10:25 AM

10 Adjourn  10:30 AM

This agenda and all other printed information related to the POD Cost Function and Investment Level Update 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 403-539-2632 or raj.sharma@aeso.ca.

Sincerely,

[original signed by]

John Martin
Director, Tariff Applications

enclosures

cc: Raj Sharma, Senior Tariff Analyst, AESO
AEO 2010 Tariff Consultation Working Groups
Terms of Reference

1 Purpose

The AEO 2010 Tariff Consultation Working Groups will be forums for stakeholders to provide perspective, advice, and expertise to the AEO on specific topics for the AEO’s 2010 tariff application. The Working Groups are intended to augment the internal capabilities of the AEO 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 AEO’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)
No party raised concerns with the treatment of ancillary service costs contained in the Application. Subject to such determinations as the Board makes elsewhere in this Decision and subject to such adjustments that may be made in the Article 11 Proceeding to interim payments made under Article 11, the AESO’s proposed treatment is approved as filed.

5.7 DTS Point of Delivery (POD) Costs and Charges

5.7.1 DTS POD Costs and Charges Overview

In section 4.3.4 of the Application, the AESO noted that in Decision 2005-096, the Board directed the AESO to use a cost-based approach to set the maximum investment formula to be used within the AESO’s customer contribution policy.

Given that the maximum investment formula derived by the AESO in response to the Board’s direction reflected the costs of POD facilities, the AESO determined that the cost function used to derive its proposed maximum investment formula could also be used to classify POD costs for DTS rate design purposes. Accordingly, the AESO developed its proposed classification of the POD portion of the DTS rate based on its proposed POD cost function as described below:

### Table 2. Original AESO POD Cost Classification Summary

<table>
<thead>
<tr>
<th>Cost Component</th>
<th>Customer</th>
<th>≤ 7.5 MW</th>
<th>&gt; 7.5 MW</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Unit Cost ($ 000 000)</td>
<td>$0.947</td>
<td>$0.621</td>
<td>$0.154</td>
<td></td>
</tr>
<tr>
<td>Billing Determinant</td>
<td>4,854.4</td>
<td>32,514.8</td>
<td>82,133.3</td>
<td></td>
</tr>
<tr>
<td>Total Costs ($ 000 000)</td>
<td>$4,596.5</td>
<td>$20,203.8</td>
<td>$12,665.6</td>
<td>$37,465.8</td>
</tr>
<tr>
<td>Classification</td>
<td>12.3%</td>
<td>53.9%</td>
<td>33.8%</td>
<td>100.0%</td>
</tr>
</tbody>
</table>

Source: Application Table 4.3.6 (Section 4, p. 14)

The AESO revised its proposed classification in its argument submission to include a third tier for loads over 50 MWs, as summarized in the following table:

### Table 3. Revised AESO POD Cost Classification Summary

<table>
<thead>
<tr>
<th>Cost Component</th>
<th>Customer</th>
<th>≤ 7.5 MW</th>
<th>&gt; 7.5 ≤ 50 MW</th>
<th>&gt; 50 MW</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Unit Cost ($ 000 000)</td>
<td>$0.947</td>
<td>$0.621</td>
<td>$0.154</td>
<td>$0.047</td>
<td></td>
</tr>
<tr>
<td>Billing Determinant</td>
<td>4,854.4</td>
<td>32,514.8</td>
<td>65,478.3</td>
<td>16,655.0</td>
<td></td>
</tr>
<tr>
<td>Total Costs ($ 000 000)</td>
<td>$4,596.5</td>
<td>$20,203.8</td>
<td>$10,083.7</td>
<td>$782.8</td>
<td>$35,655.3</td>
</tr>
<tr>
<td>Classification</td>
<td>12.9%</td>
<td>56.6%</td>
<td>28.8%</td>
<td>2.2%</td>
<td>100.0%</td>
</tr>
</tbody>
</table>

Source: AESO Argument Table 3.4.1 (p. 44 of 99)

In reply, parties took issue with the substance of the classification proposed in the AESO’s argument.

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128 In light of the AESO’s proposal to use the same cost based function as the basis for both its maximum investment formula and its proposed DTS POD charge rate design, for ease of reference, the Board will refer to the underlying relationship between average POD costs and POD capacity as the “POD Cost function”. In adopting this convention, the Board acknowledges the views of some parties that cost functions used for contribution policy purposes and rate design purposes should be different. The Board addresses this issue in section 5.7.3 of the Decision.
After evaluating the information on the record, Board staff developed an alternative POD cost function using the curve estimation functions used by the AESO in its Argument to determine the slope of its proposed POD cost function for PODs larger than 50 MW. Board staff considered whether the use of the non-linear curve functions considered by the AESO could be used to determine a continuous cost function for all sizes of PODs.

Board staff used the 30 greenfield data points, and augmented this data with the 13 data points available below 7.5 MW and the five data points available above 50 MW. This is the same 48 point data set used by the AESO in its final proposed cost function. The AESO used the 30 POD greenfield dataset in conjunction with the 13 TCCS dataset PODs below 7.5 MW to determine the first two tiers of its proposed POD cost function. The AESO used a 96 POD subset of the 109 POD TCCS dataset to determine the slope of its proposed POD cost function above 50 MW.

After observing that a power function provided the best overall fit to the 48 point data, Board staff then developed a series of linear equations, to approximate this curve. The linear equations were based on the calculated power function (or y-axis) values associated with the 0.10MW (first data point), 7.5MW, 17MW, 40MW, and 122.8MW data points (last data point).

By letter dated October 25, 2007, the Board invited comments and reply from parties on the cost function developed by Board staff. The Board received comments and reply from numerous parties. The Board also received responses to information requests posed to the AESO from the Board regarding alternate cost functions developed by the AESO during the comment and reply process. DUC also developed alternate cost functions during this process.

Throughout this proceeding, parties provided extensive and wide ranging evidence on the appropriateness of the POD charge component of the DTS rate design. The Board considers that the submissions relating to the POD charge generally fell into the following major subject areas:

- Board Directions Regarding POD Cost Classification;
- Alignment of POD Charge and Contribution Policy Cost Functions;
- POD Cost Economies of Scale;
- POD Cost Function Dataset;
- Statistical Fit of POD Cost Function;
- Parameters of POD Cost Function;
- Other POD Charge Related Issues

The Board addresses each of the above issues in the following sections of this Decision. In summary, in the remainder of this section 5.7 of the Decision, the Board has found that:

- the AESO has investigated POD costs as required by Decisions 2005-096 and 2005-132;\(^\text{131}\)

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\(^{129}\) AESO Argument, p. 75

\(^{130}\) The AESO, DUC, ASBG-PGA, AE, PPGA, CCA, PICA, ADC, Fortis, and IPCAA provided comments on the alternate cost function.

• it is appropriate to use the same POD cost function for the purposes of both the POD charge and the maximum investment function under the AESO’s contribution policy;
• the impact of economies of scale on POD costs is significant as capacity increases and is to be reflected in the POD cost function and design of the POD charge;
• it is appropriate to use the best available data to determine the POD cost function for the purposes of both the POD charge and the AESO’s contribution policy;
• the statistical fit of the POD cost function approved by the Board in section 5.7.7 of this Decision was sufficient to support its use for both POD charge and contribution policy purposes;
• a non-linear function best describes the of POD cost economies of scale;

Based on the evidence filed by the parties, the Board approves a multi-tiered linear function, as described in the remainder of section 5.7 of this Decision that reflects these findings.

While section 5.7 of the Decision considers the POD charge component of Rate DTS, it is evident that a large part of the POD charge submissions related to the appropriateness of the POD cost function proposed by the AESO for the purpose of establishing both the POD charge as well as for the maximum investment function under the customer contribution policy. Accordingly, as appropriate, the Board has taken into account submissions received on the POD cost function in relation to the customer contribution policy within this section of the Decision.

5.7.2 Board Directions Regarding POD Cost Classification

In section 4.3.4 of the Application, the AESO noted that Decision 2005-096 established that cost is the appropriate basis for the maximum investment function used within the AESO’s customer contribution policy. In response to Direction 13A\textsuperscript{132} of Decision 2005-096 and after analyzing additional data, the AESO proposed the following cost function for its maximum investment function set out in section 6 of the Application:\textsuperscript{133}

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

The AESO submitted that the Board had been clear that the investment function and the function for the POD charge were to be cost based, and that it had developed its proposed POD charge in compliance with the Board’s direction.\textsuperscript{134} In its rebuttal evidence, the AESO noted that several references in Decision 2005-096 suggested that cost should underlie the development of both the investment function and the design of the DTS rate.\textsuperscript{135}

The AESO’s interpretation of Board directions related to POD costs, as used in the development its proposed DTS POD charge, generated argument submissions by several parties.

\textsuperscript{132} As discussed in section 9.1 of this Decision, the Board has adopted a convention for numbering Board directions based on the AESO’s refiling application (Application #1420890) in relation to Decision 2005-096, as approved by the Board in Decision 2005-131
\textsuperscript{133} Ex. 007, Application, Section 6, p. 22
\textsuperscript{134} AESO Argument, pp. 69-70
\textsuperscript{135} Ex. 347, AESO Rebuttal Evidence, pp. 2-3, citing Decision 2005-096, pages 17, 26, 27, 56
PPGA submitted that acceptance of AESO data for the purposes of determining the AESO’s investment function should not imply acceptance of that data for POD charge rate design purposes. It also submitted that whereas the POD charge is based on embedded costs, the AESO’s investment policy is forward looking. PPGA submitted that these two purposes are different. It further questioned the accuracy of the data set used by the AESO and DUC in establishing their POD charge proposals. PPGA noted that while the Board had directed the AESO to have a cost based POD function, the Board did not require the AESO to link the POD and investment functions.

DUC noted that the AESO’s TCCS in the 2006 AESO tariff proceeding indicated that POD costs contained a large fixed component, which led to the Board’s approval in Decision 2005-096 of a monthly charge of $21,899.

DUC submitted that the Board’s directions in Decision 2005-096 anticipated that the AESO’s interconnection cost function would exhibit significant economies of scale and could, as a result, be non-linear in nature. DUC further submitted that, in response to smaller sized customers that had expressed concern about the large price increase resulting from the large fixed POD charge approved in Decision 2005-096, the Board provided relief to customers under five MW in size. DUC referred to Decision 2005-132, in which the Board directed the AESO to perform further analysis on POD costs and to file the analysis with its 2007 GTA. DUC submitted that while the AESO had, in large part, responded to the Board’s directions, the AESO’s investment function, POD charges, primary service credits, and maximum investment amounts should be enhanced to better reflect the cost causation for larger PODs.

While parties focused primarily on Board directions arising from Decision 2005-096 and, to a lesser extent Decision 2005-132, a key Board direction leading to the eventual establishment of a POD charge arose from Decision 2001-32. In that Decision, the Board directed the predecessor of the AESO to carry out a cost of service study to be used in developing the tariff structure for the 2003 GTA. This direction was fulfilled by the AESO through preparation of the TCCS filed in its 2005-2006 GTA. The Board was persuaded by the TCCS that POD costs amounted to approximately 24% of total costs and that POD costs as identified in the TCCS should be recovered by way of a customer-related charge.

As pointed out by the PPGA, Direction 13A from Decision 2005-096 related to the maximum investment formula to be used in conjunction with the AESO’s customer contribution policy. It did not relate to the POD charge portion of the DTS rate.

Decision 2005-132 arose from a Board initiated application to review and vary the impacts of the POD charge approved in Decision 2005-096 on the smallest AESO customers. In Decision 2005-132 the Board approved a temporary exception from the finding in Decision 2005-096 that cost causation should be the primary determinant of the POD charge design. However, as indicated in Decision 2005-132, the redesigned POD charge set out in that decision was intended to be a

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136 PPGA Argument, p. 21
138 Decision 2001-32 direction 21 (p. 215)
139 Decision 2005-096, p. 28
140 Decision 2005-096, p. 29
“stop gap” measure to apply until further and more detailed cost causation research could be completed.\textsuperscript{141} Therefore, after having provided rate relief to small customers for 2006, the Board provided clear directions to the AESO in Decision 2005-132 to undertake additional analysis of POD costs to be filed with the AESO’s 2007 GTA. Specifically, the Board directed the AESO to collect information on the items comprising POD costs, the costs of PODs serving smaller loads as compared to those serving larger loads, whether a reasonable cost breakpoint exists between smaller and larger PODs, and the additional relief, if any, that should be offered to customers who have paid for their own transformation equipment.\textsuperscript{142}

The direction from Decision 2005-132 is a reinforcement of the Board’s general desire that cost causation should, for the most part, drive the AESO’s DTS rate design. The Board deals with the question of how well the AESO’s proposed POD cost function reflects the causation of costs in section 5.7.7 of this Decision. The Board considers that the AESO has appropriately investigated POD costs as required by Decisions 2005-096 and 2005-132.

The Board considers that its finding that cost causation is the rate design criterion to be afforded the most weight applies to the POD charge and not solely to the rate design for recovering bulk and local system costs.

5.7.3 **Alignment of POD Charge and Contribution Policy Cost Functions**

The AESO noted in section 4.3.4 of the Application that Direction 13A from Decision 2005-096 required it to analyze additional data for the purposes of recommending a revised maximum investment function. The AESO suggested that since the underlying cost function used to develop its proposed maximum investment function reflects costs caused by a customer interconnection at a POD, that cost function should also be used to classify POD costs.\textsuperscript{143}

A number of parties, for example, the Consumers Coalition of Alberta and the Public Institutional Consumers of Alberta (CCA/PICA) and PPGA made submissions in argument, disagreeing with the AESO’s decision to use the same underlying cost function as the basis for both its maximum investment function under the contribution policy and its classification of POD costs through its proposed POD charge.

The AESO disagreed. It submitted that as both the POD charge and the investment function present price signals which can only affect future customer behaviour, but not cause past costs to be avoided, using a common POD cost function for both purposes would be appropriate. The AESO considered that its proposed POD cost function should establish the structure or shape (i.e. the relationship between fixed ($/month) and demand ($/MW) components) of the function.

PPGA noted that whereas the AESO presented the TCCS in its 2005-2006 GTA, the AESO did not recommend using that data in support of a POD charge to be levied on customers. While the notion of linking the investment and POD charge cost functions might appear rational, PPGA submitted that the purposes of the POD charge and the investment function are very different. Whereas the investment function deals with forward looking decisions, the POD charge is an allocation of the historical net book cost of radial lines and substations to all PODs. Given the

\textsuperscript{141} Decision 2005-132, p. 4  
\textsuperscript{142} Decision 2005-132, p. 4  
\textsuperscript{143} Ex. 005, Section 4.3.4 of the Application
consequences on smaller customers from a dramatic shift in POD costs to them, PPGA submitted that the AESO has not provided adequate evidence that relative proportions (i.e. Y-intercept and slopes) from the investment function were representative of the all POD data.

DUC submitted that the Board clearly articulated in Decision 2005-096 that cost causation was the primary rate design criteria. DUC further submitted that the cost causation principle dictates that all components of the rate design need to reflect cost causation. In particular, it considered that each of the DTS rate POD charges, PSC rates and maximum investment amounts should be aligned and derived from the interconnection cost function which reflects cost causation for POD interconnections. Accordingly, DUC agreed with the AESO that DTS POD charges and maximum investment amounts should be aligned, but disagreed with the AESO decision not to bring PSC rates into alignment with POD charges.

DUC submitted that a fundamental design consideration for the POD charge is whether it is intended to recover costs based on historical cost causation or future cost causation. DUC noted that this question is generally not relevant to most rate design exercises since future costs are recovered in the same manner as historical costs. However, it noted that the AESO’s current policy is to only invest in a single transformer for new customer connections, which DUC submitted was different than the historical practice of providing more than one transformer for larger services. Notwithstanding the change in the AESO’s policies regarding transformer investment, DUC submitted that its evidence demonstrated that DUC’s proposed interconnection cost function was appropriate from a historical and future cost causation perspective.144

The Board considers that it is appropriate that, to the extent possible, the POD charge component of Rate DTS reflect cost causation. Accordingly, it is necessary to use a cost function that provides the best possible representation of the manner in which POD costs are caused.

The Board considers that an assessment of the AESO’s proposed POD cost function proposed to be used in determining the POD charge component of Rate DTS must reflect the fact that the POD cost function is used only to allocate costs previously functionalized as POD related costs in the TCCU. The Board considers that a POD cost function derived for contribution policy purposes appropriately describes the fixed and variable proportions of TFO costs functionalized as POD related as between customers of different sizes because, as described below, the Board is unable to find that underlying shape of the average cost would be materially different.

While the Board acknowledges the observation of the PPGA that the Board’s directions in Decision 2005-096 did not specifically direct the AESO to use a cost function to derive a maximum investment function for the purposes of developing a POD charge, the Board strongly agrees with the AESO that the contribution policy investment function and the POD charge cost function are both representative of the same set of underlying costs. As such, the Board finds that it is reasonable for the AESO to have proposed that the same underlying average cost function be used for both of these two purposes.

144 A footnote at p. 7 of DUC’s argument references DUC argument at pp. 18-19. At pp. 18-19, DUC explains that a recommended “third tier” in its proposed cost function using data provided in the AESO’s rebuttal evidence was based on five data points. Of the five data points, DUC noted that 4 of the data points described the cost of four PODs served by more than one transformer, two PODs that are served by more than one transmission line and one POD that is served at 245kV.
The PPGA’s submissions placed considerable focus on differences between embedded historical costs and a forward looking POD cost function devised to set maximum investment allowances under the customer contribution policy. However, the PPGA did not substantiate its claim. As a result, the Board is unable to conclude that the shape of a historical POD cost function and a forward looking POD cost function would be materially different.

Given that the maximum investment function was designed to reflect the “one-line, one-transformer” standard, whereas existing PODs may have more than one transformer and/or lines, it was incumbent on the Board to assess whether this consideration would cause the underlying shape of a cost function for POD charge purposes to be different from a cost function reflecting only the cost of standard facilities for the purposes of the contribution policy’s maximum investment function.

However, DUC observed that it is generally at larger PODs where additional transformers are more likely to be deemed desirable.145 Thus, the Board considers that any potential distortion of the cost causation principle arising from the use of a POD cost function based on only standard facility costs tend to occur in larger rather than smaller PODs, since multiple transformers tend to exist only in larger PODs. As noted by DUC in argument, four of the five historical cost data points (supplied by the AESO) represented PODs with more than one transformer.146 Therefore, as the Board has used the cost data for the five PODs referred to by DUC for its approved POD cost function, the underlying shape of the cost function for POD charge purposes does not differ from the POD cost function used for the purposes of the contribution policy’s maximum investment function. Thus, the Board finds that it is appropriate to use the same POD cost function for the purposes of both the POD charge and the maximum investment function under the AESO’s contribution policy.147

5.7.4 POD Cost Economies of Scale

In Appendix F to the Application, the AESO indicated that it had analyzed data collected to develop its proposed interconnection cost function to determine whether the data exhibited any significant economies of scale, whether the relationship between contract capacity and cost was linear or non-linear in nature and/or if any relationships other than contract capacity and cost existed. Appendix F also noted that examination of cost data for 30 greenfield interconnection projects had established that a linear function appropriately represented the relationship between average cost and capacity. The AESO noted, however, that an analysis of subsets of the greenfield data did not improve the R² of the regression lines as compared to the regression line produced from all 30 data points. The AESO also noted that non-linear regression analysis was also performed but did not provide better regression coefficients than the linear analysis. Accordingly, the AESO considered that a single straight-line average cost function provided the best representation of the average cost of the 30 greenfield projects.

The extent to which POD cost data exhibited economies of scale was discussed more extensively in the evidence of DUC. In its evidence, DUC submitted that the AESO’s analysis did not reflect

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145 Ex. 229, DUC Evidence, p. 30
146 DUC Argument, p 7 and 18-19, citing AESO Rebuttal Evidence pp. 1-2
147 DUC Argument, p 7 refers to Exhibit 305 – 80% of PODS above 40MW have more than 1 transformer.
the significant economies of scale present in PODs over 40 MW. DUC submitted that there is not a linear correlation between substation costs and DTS capacity for larger substations.\textsuperscript{148}

DUC anticipated that while substations would have some level of fixed costs and would have some incremental costs related to size, substation costs did not continue to increase at the same rate with size. In particular, DUC noted that evidence filed by TCE in the AESO’s 2005-2006 GTA indicated that both transmission line and substation costs exhibited economies of scale.\textsuperscript{149}

In its argument, PPGA proposed a POD charge comprised of a fixed monthly charge and a uniform per MW rate. PPGA submitted that the AESO’s proposed POD cost function would lead to its members receiving a proportionately larger increase in rates as compared to larger load customers who receive the benefit of economies of scale for certain components of the POD charge. PPGA submitted that there are numerous factors which impact the determination of the POD charge that do not result in decreasing unit costs based solely on achieving economies of scale.

PPGA submitted that the POD charge evidence of DUC focused solely on economies of scale for substations but ignored other factors such as the cost of radial lines and other considerations that impact overall POD costs. In addition, PPGA submitted that DUC made several acknowledgements which PPGA considered to counteract the tendency of PODs to exhibit economies of scale. PPGA submitted that DUC’s view ignored parameters such as line length, terrain, rural as compared to urban locations; telecommunication needs, voltage level, conductor size and structure types. Accordingly, PPGA submitted that not only were there no economies of scale associated with many factors that influence POD costs, many aspects of POD costs actually exhibit diseconomies of scale since costs increase as POD size increases.

In argument, and in recognition of DUC’s evidence, the AESO proposed an additional tier for its POD cost function to reflect an incremental cost of $47,000/MW for interconnections above 50 MWs.\textsuperscript{150} However, the AESO submitted that whereas DUC had indicated that the primary cost driver above 40 MWs should be limited to transformation, DUC had failed to account for factors that create additional complexity and cost when capacity exceeds 40 MWs.

In response to an information request, DUC provided a helpful conceptual explanation for the tendency of the average cost of PODs to exhibit economies of scale with increases in POD capacity.\textsuperscript{151} In that response, DUC indicated that the major cost components of a substation (such as installation costs, land, ground grid, support structures, switches and communication/protection equipment) are either fixed or exhibit limited economies of scale. However, DUC indicated that once the base substation equipment is installed, increasingly large substations generally require larger transformers only to increase capacity. DUC’s evidence provided support for the notion that transformer costs increase at a decreasing rate with capacity increases.\textsuperscript{152} The Board finds that DUC’s evidence on the drivers of POD costs provided compelling evidence of substantial economies of scale.

\begin{flushleft}
\textsuperscript{148} Ex 229, DUC Evidence, pp 12-13 citing Application Appendix G spreadsheet, tab Subs and DUC POD PSC evidence App G revised.xls, tab subs chart.
\textsuperscript{149} Ex. 229, DUC Evidence, p. 14, citing Exhibits 23-010 and 02-019-001 from AESO 2005-2006 GTA proceeding.
\textsuperscript{150} AESO Argument, p. 77 of 99
\textsuperscript{151} Ex. 306, CG-DUC-1(c)
\textsuperscript{152} Ex. 229, DUC Evidence pp. 13-16
\end{flushleft}
PPGA expressed the view that POD facilities exhibit increasing economies of scale due to the minimum y-intercept component of POD costs making a smaller portion of the cost of larger PODs. The Board agrees that fixed costs are an important component of POD cost economies of scale. This is also reflected in the conceptual explanation of the drivers of economies of scale provided by DUC. However, the Board is not persuaded by the assertions of the AESO and PPGA that diseconomies of scale occur that to such an extent as to offset the contributors to economies of scale described by DUC.

In this regard, the PPGA panel filed an extract from the tariff of SaskPower with its opening statement with the apparent intention of demonstrating diseconomies of scale. However, the Board considers that this claim was effectively countered by the DUC panel which noted that the increase in charges with size in the SaskPower tariff extract reflects the fact that SaskPower customers generally own their substations but must use metering equipment supplied by the utility. PPGA suggested that the cost of responding to landowner opposition may increase as the POD cost size increases. The Board also considers that PPGA did not provide a persuasive explanation of why the cost of responding to landowner opposition would vary with the size of a new interconnection, nor did it provide supporting evidence demonstrating this claim.

The Board agrees with DUC that the average cost of transmission interconnections will exhibit significant economies of scale with increasing capacity. The Board further concludes based on the evidence provided by DUC that a POD cost function expressed as dollars per MW should be non-linear in shape in recognition that certain components of POD costs (most notably the cost of transformers) tend to increase at a decreasing rate with the capacity of the interconnection.

5.7.5 POD Cost Function Dataset

In section 4.3.4 of the Application, the AESO proposed a POD cost function primarily based on a detailed examination of 30 greenfield projects built between 1999 and 2006 representing 516.7 MW of DTS capacity and total project costs of $213.2 million. Linear regression analysis was used to determine the average cost function. As no projects less than 7.5 MWs were included in the 30 project dataset, the AESO used a small subset of POD cost information drawn from the TCCS to determine a cost function for smaller projects. The AESO recognized that the POD cost classification used in its contribution policy study was significantly different from the minimum intercept analysis performed for the TCCS. However, the AESO submitted that its proposed classification was appropriate because it recognized that a different cost function would be appropriate for smaller projects.

DUC generally supported the AESO’s use of regression analysis on the 30 POD greenfield dataset as augmented to include the 13 small project dataset as an appropriate method for developing POD charges. DUC submitted, however, that the AESO’s analysis should have

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153 Ex. 331, IPCAA.PPGA-1
154 Ex. 306, CG-DUC-1(c)
155 Ex. H-029
156 Tr. Vol. 6, pp. 1319-1323
157 Tr. Vol. 6, p. 1313
158 Ex. 015, Appendix F to the Application
159 DUC Argument, pp. 14-16
considered the lower unit interconnection costs of large PODs. The Board agrees with DUC that economies of scale for large PODs should be reflected in the POD cost function.\textsuperscript{160}

PPGA expressed a number of concerns with the POD cost function data set analyzed by the AESO.\textsuperscript{161} While the PPGA highlighted that the data used by the AESO was not optimal, the Board considers that the AESO used the best POD cost data available. The Board also considers that the PPGA’s evidence failed to establish that the all POD data was superior or even adequate for establishing a POD cost function for either the POD charge or the AESO’s contribution policy’s maximum investment function. Even if the Board was to have found that the AESO’s dataset is inadequate, it does not follow that the PPGA’s approaches are adequate. Nor does it follow that the status quo is preferable.

Another key theme of the PPGA’s criticisms was that the greenfield dataset used to analyze POD costs was collected for a different purpose (to comply with a Board direction related to the contribution policy), not for the purpose of refining the POD charge component of Rate DTS. PPGA submitted that the analysis of POD costs for contribution policy purposes is focused on cost causation looking forward, and that this looking forward orientation is not appropriate for determining the allocation of embedded POD costs.\textsuperscript{162} The Board does not agree. While rate design entails recovery of the revenue requirement, and thus recovery of embedded costs, the Board considers that cost allocation should also reflect the manner in which costs are expected to be caused in the future. Accordingly, as the goals of POD charge design and customer contribution investment function design are not in conflict, the Board finds that the largely unverifiable all POD dataset (or a subset of that data) is not inherently superior for POD charge purposes than the greenfield dataset used by the AESO.

To the extent possible, the POD cost function should endeavor to represent the functional relationship between the full DTS capacity of the POD and the full cost of constructing a complete POD. Thus, one key advantage of the greenfield dataset is the significant effort devoted by the AESO to ensure that the datapoints are comparable to one another. In this regard, while the AESO’s discussion in Appendix F of the Application is specifically related to a 13 POD subset of the 109 data points for which vintage could be established, the comparability issues identified by the AESO in Appendix F would apply to all data derived from the TCCS. The Board considers that the issues addressed by the AESO with respect to the greenfield data are generally of equal or greater concern in respect of potential the use of the 109 POD subset of the all POD data for POD cost function determination purposes.\textsuperscript{163}

In order to be useable for the purposes of designing a POD cost function, the Board must have confidence that all of the data points are reflective of comparable circumstances. However, as there is no way to verify whether the 109 POD dataset data points are comparable to one another, the Board concludes that the greenfield dataset is the only available POD cost dataset that has been subject to sufficient analysis to form a reliable basis for determining a cost causation function.

\begin{flushleft}
\textsuperscript{160} DUC Argument, p. 16  
\textsuperscript{161} PPGA Argument, pp. 10-11  
\textsuperscript{162} PPGA Argument, p. 16  
\textsuperscript{163} Ex. 015, Application, Appendix F, p. 20
\end{flushleft}
Using 13 all POD dataset data points to represent PODs with capacities below 7.5 MWs and an additional five all POD dataset data points to represent PODs with capacities greater than 43.2 MWs raises issues with respect to its comparability with the greenfield dataset. However, the Board finds these additional data points are the best available POD cost data for projects in these contract capacity ranges. Moreover, since the Board is strongly persuaded that the relationship between POD costs and contract capacity will exhibit economies of scale, the Board considers that a much more significant distortion of the POD cost function would occur if these data points were to be excluded than any potential for distortion that may be caused by incompatibilities with the greenfield data. Thus, in section 5.7.7 below, the Board uses this augmented 48 POD dataset as the basis for the POD cost function approved by the Board.

5.7.6 Statistical Analysis of POD Cost Function

In section 6.5.3 of the Application, the AESO stated that it had conducted extensive stakeholder discussion to fulfill the obligations arising from Direction 13A of Decision 2005-096. The AESO noted that it had performed both linear and non-linear regression analysis on the greenfield POD data but that it had determined that a simple linear function provided the best representation of the cost of the 30 greenfield projects. In addition, the AESO indicated that it had examined whether projects of different sizes within the greenfield project dataset exhibited different cost functions by performing statistical analysis on subsets of the 30 project data. The AESO noted that this subset analysis did not produce a regression coefficient greater than the 0.26 level obtained through regression analysis of the entire 30 POD greenfield data set.

A number of parties made submissions regarding the dispersion of the POD cost data and the adequacy of the R² values obtained through regression analysis on that data.

The Board considers that the comparatively low R² values reflect the fact that factors unrelated to a POD’s DTS contract capacity will have a significant impact on the cost of specific PODs. In particular, there is evidence that transmission line costs associated with specific PODs are generally not strongly related to the capacity of the POD. As a result, it is understandable that the POD data could exhibit significant dispersion. It is therefore understandable that a statistically derived dollars per MW POD cost function would not necessarily exhibit high R² values.

While the statistical fit may not be high, the Board does not consider that statistical analysis should be discarded solely on the basis that R² values fall in the lower range. All things equal, the Board considers that a significantly higher R² value is generally preferable to a function with a lower R² value as long as the resulting POD cost function appears to reasonably reflect underlying cost relationships such as the effects of economies of scale described in section 5.7.4 above.

5.7.7 Parameters of POD Cost Function

The AESO initially proposed a POD cost function consisting of a y-intercept of $0.947 million and two linear functions tiers with a first tier slope of $0.621 million per MW to 7.5 MWs and a second tier slope of $0.154 million per MW beyond the 7.5 MW breakpoint. However, in
section 4.1.7 of its argument, the AESO amended its proposed POD cost function to add an additional breakpoint and additional tier beyond 50 MW. As discussed above in section 5.7.1, a proposed POD cost function was devised by Board staff from the evidence filed by the parties and was circulated for comment in Board correspondence dated October 25, 2007. The AESO and several interveners submitted comments on the POD cost function devised by Board staff.

The AESO submitted in its argument that in order to consider the impact of large project costs within its revised POD cost function, it had incorporated cost data from 109 interconnection projects into its analysis. The AESO noted that it had performed regression analysis on TFO projects ranging in capacity from 7.6 MW to 122.8 MW using linear, polynomial, power and exponential curves with results as reported in Table 4 of its argument (reproduced below):

Table 4.  Results of POD Cost Regression Analysis Described in AESO Argument

<table>
<thead>
<tr>
<th>Regression Analysis</th>
<th>Line Function</th>
<th>Correlation Coefficient</th>
</tr>
</thead>
<tbody>
<tr>
<td>Linear</td>
<td>$y = 0.0985x + 5.7659$</td>
<td>$R^2 = 0.1289$</td>
</tr>
<tr>
<td>Logarithmic</td>
<td>$y = 3.8486 \ln(x) - 3.1694$</td>
<td>$R^2 = 0.1939$</td>
</tr>
<tr>
<td>Polynomial</td>
<td>$y = -0.0017x^2 + 0.2271x + 3.2723$</td>
<td>$R^2 = 0.1843$</td>
</tr>
<tr>
<td>Power</td>
<td>$y = 1.8957 x^{0.431}$</td>
<td>$R^2 = 0.1799$</td>
</tr>
<tr>
<td>Exponential</td>
<td>$y = 5.1281 e^{0.113x}$</td>
<td>$R^2 = 0.1249$</td>
</tr>
</tbody>
</table>

Source: Table 4, AESO Argument, p. 76

The AESO noted that the highest regression coefficient was achieved with a logarithmic function, which had a value of 0.1939. The AESO also submitted that the slope of the logarithmic curve would better represent the cost of projects with capacities greater than 50 MW than both the AESO’s initial proposed function and cost function proposed by DUC. The AESO also submitted that a multi-part linear function would be consistent with the Board’s expectations as indicated in Directive 13A. The AESO also elaborated on its rationale for proposing a 50 MW breakpoint.166

PPGA devised a proposal with a fixed charge to reflect a minimum cost associated with a POD and flat per MW charge to reflect the need to recover the residual portion POD charge revenue requirement not recovered through the customer charge.

In anticipation of the possibility that the Board might use the AESO’s cost causation data, PPGA also devised an alternate proposal. PPGA noted that it had conducted a series of regression analysis that demonstrated that a breakpoint of 17 MW had the highest level of $R^2$ for the slope above the breakpoint and for the slopes of both regression lines. PPGA contrasted the 17 MW breakpoint suggested for its alternate proposal with the AESO’s proposed 7.5 MW breakpoint which, in PPGA’s view, represented no more than a disconnect point between two different data sets and two different equations. PPGA also noted that unlike the AESO’s (original) proposal, the y-intercept and slopes for its alternate proposal were derived from its regressions on the dataset.

In argument, while DUC was generally supportive of the AESO’s (original) methodology up to 40 MW of billing capacity, it submitted that the AESO’s proposal should be adjusted to reflect cost causation and the significant economies of scale present for larger PODs. Accordingly,
DUC proposed a POD cost function identical to the AESO’s proposal up to 40 MWs but with an additional tier above 40 MW and a proposed slope of $30,000/MW.

ADC commented all parties agreed that there are economies of scale in building a POD and that the customer portion of the POD charge should, at minimum, be at the level proposed by the AESO.

ADC submitted that the PPGA’s primary proposal assumes that the cost of a substation is linearly proportional to size, which ADC submitted was not supported by any evidence. ADC submitted that a multi-linear function consisting of a series of lines would follow the POD cost function more closely than a simple straight line. Accordingly, if a 17 MW breakpoint was to be used, ADC submitted that the 17 MW breakpoint should only be used in addition to breakpoints at 7.5 MW and 40 MW.

The Board considers that each of the POD cost function proposals devised by the AESO, the PPGA and DUC had, to varying degrees, flaws that prevented the Board from wholly adopting any one party’s specific proposal. As is further described below, the Board finds that the POD cost data on record is adequate for the Board to devise an appropriate POD cost function. The Board has relied on a set of 48 data points consisting of the 30 POD greenfield data set contained in the Application, the 13 small pod data contained in the Application and five large pod TCCS data described in the AESO’s rebuttal evidence. This dataset was provided as an appendix to the Board’s letter to the AESO and all Intervenors dated October 25, 2007.

As discussed in section 5.7.4 above, the Board has accepted that POD costs exhibit significant economies of scale with increasing capacity. As a result, the Board finds that PPGA’s primary proposal consisting of only a fixed charge and a $/MW charge must be rejected because it does not reflect the tendency for POD costs to increase at a decreasing rate with capacity.

Given the existence of significant POD cost economies of scale, the Board considers that the function representing the relationship between POD cost and DTS capacity should have a non-linear shape. However, a reasonable representation of this underlying non-linear function may be represented by a continuous POD cost function from a series of linear functions with different slopes that intersect at specific breakpoints. Accordingly, the Board finds that a compound POD cost function consisting of at least two tiers of linear functions with different slopes (and two breakpoints between the three tiers) would reasonably approximate the underlying POD cost function.

The two tier/17 MW breakpoint POD cost function suggested in the PPGA’s alternate proposal was derived by performing separate regressions on subsets of the greenfield data above, occurring both above and below potential breakpoints. However, the Board does not agree that PPGA’s alternate proposal is superior based simply on the comparatively higher R² values obtained by the PPGA (by performing separate regressions on data above and below the 17 MW breakpoint). Of particular concern to the Board is while that PPGA’s alternate proposal uses both the slope and intercept of the regression on POD data with capacities below 17 MWs, only the

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167 Ex. 016, Application, Appendix G, Spreadsheet tab “Greenfield”, cells C3:D32
168 Ex. 016, Application, Appendix G, Spreadsheet tab “All Projects”, cells C38:D50
169 Ex. 347, AESO Rebuttal Evidence, page 1
slope of the regression (but not the intercept) derived from above 17 MW data is used when PPGA assembles its slopes and breakpoints into a continuous function. Effectively, PPGA’s alternate approach ignores the fact that while its below 17 MW regression line has a y-intercept of $1,579,015, PPGA’s above 17 MW regression has an intercept of only $865,018 – well below the intercept of the below 17 MW dataset regression.\textsuperscript{170} As a result, the intersection or breakpoint of the two equations occurs at a value of negative 3.69 MWs, not positive 17 MWs.

The PPGA’s proposal to derive a continuous function by assembling the two regressions at the 17 MW breakpoint results in a cost function that is above the greenfield dataset POD cost values for all PODs larger than 17 MWs. As PPGA’s alternate POD cost function clearly does not represent an average cost per MW function, the Board considers it to be fundamentally flawed and it is therefore rejected by the Board.

The POD cost functions proposed by the AESO and DUC do not have the same fundamental flaw of PPGA’s alternate proposal because they are both primarily based on a single linear function derived through regression analysis on the 30 POD greenfield dataset. These proposed POD cost functions are not without concerns, however.

The first concern is that the AESO and DUC proposals were based on a primary linear cost function with an R² value of only 0.26. As further discussed below, the Board has determined that a much better statistical fit may be demonstrated when a different functional form is used.

A second concern relates to the minimum intercept and first tier slope of the AESO’s original and revised proposal (and by implication, DUC’s proposal). While AESO has indicated that 13 small project data points have been used to devise a cost/capacity relationship for the first tier of the POD cost, both the slope and minimum intercept for the first tier of the AESO’s proposed POD cost function relies on only one of the 13 small POD data points.\textsuperscript{171} In particular, in Appendix F of the Application, the AESO describes its process for determining the minimum y-intercept of the POD utilizing an “interpolated function” derived by determining the multiplier (0.21275) of the greenfield POD average cost function representing “the threshold below which no project costs were recorded.”\textsuperscript{172} Accordingly, the Board finds that neither the slope of the first tier nor the AESO’s proposed $0.947 million minimum cost or y-intercept have sufficient validity to be used as the basis for the first tier of the POD cost function.

Board staff used a similar approach to that put forth by the AESO in its argument\textsuperscript{173} based on different types of regression analysis performed by Board staff on the 48 point dataset, using linear, logarithmic, polynomial, power, and exponential functions. The results of this analysis are shown below:

\textsuperscript{170} Ex. 328 –Attachment to DUC.PPGA-002(c) (excel file), Tab “Classification 17”
\textsuperscript{171} Ex. 015, Application Appendix F, p. 20
\textsuperscript{172} Ex. 015, p. 21
\textsuperscript{173} AESO Argument, p 76
The power function provided the best statistical ($R^2$ of 0.49) and visual fit to the 48 point dataset. Further, this function has the advantage of being continuous in nature, as opposed to the multiple breakpoint linear functions proposed by parties. As a result, unlike the alternate proposal function proposed by the PPGA, the power function does not have the problem of ensuring that the separate linear functions actually converge at the proposed breakpoints.

The Board agrees with the observation of the ADC that a multi-linear function consisting of a series of lines would follow the POD cost function more closely than a simple straight line. Accordingly, Board staff fitted a series of linear functions to replicate the slopes of the power function for various breakpoints. Board staff tested a function with a 7.5 MW and 40 MW breakpoint, another with a 17 MW and 40 MW breakpoint, and finally one with 7.5 MW, 17 MW and 40 MW breakpoints.

The cost functions resulting from the linear approximations of the power function, the power function, and the AESO’s final proposed function, are shown below:
Board staff considered that the function with the 7.5MW, 17MW, and 40MW best replicated the power function, and as such this was the POD cost function on which the Board sought submissions from the parties pursuant to its letter dated October 25, 2007. The resulting POD cost function developed by Board staff and on which submissions were sought from the parties was as follows:

\[ Y = \$0.894 \text{ million} + \$0.503 \text{ million/MW for the first 7.5MW} + \\
\$0.174 \text{ million/MW for the next 9.5MW} + \\
\$0.102 \text{ million/MW for the next 23MW} + \\
\$0.054 \text{ million/MW for all MW above 40.0MW}. \]

During the comment process, a number of parties reiterated their support for their proposed POD cost functions provided earlier in the proceeding. Having reviewed these additional submissions, the Board was not persuaded that its proposed POD cost function was inappropriate.

The submissions received, in response to the October 25, 2007 request for comments on the POD cost function under consideration, generally related to (a) the appropriateness of using the 48 data point POD power function proposed by Board staff as the underlying function; and (b) the proper approach for determining a linear approximation of the underlying POD cost for DTS rate and investment policy purposes.

The AESO raised issues regarding the use of the 48 point dataset suggesting that the 13 small project data points and five large project data points drawn from TFO cost data may be incompatible with the 30 POD greenfield data set.

The Board understands parties’ concerns and agrees that the 13 and five data points are not identical to the 30 greenfield data. However, on balance, the Board considers that a continuous cost function is more robust and desirable as it is inclusive of more varied POD data. The Board also agrees with the ADC that a greater error would be created by ignoring the small and large POD data, thereby not representing the effects of economies of scale in the POD cost function. DUC also observed that a POD cost function derived using a power function regression on the 109 POD TCCS data is substantially similar to the power function derived from the 48 POD data set. The Board considers these similarities to be a further indication that use of the 48 POD dataset does not distort the resulting POD cost function.

Although the AESO put forward a non-zero intercept power function,\(^{174}\) which it submitted had a higher R\(^2\) value than the power function developed by Board staff, it did not suggest that it be used as the basis for a revised cost function. The Board did not fully understand the AESO’s rationale for developing a non-zero power function for consideration while not suggesting it be adopted, and sought further clarification by way of an information request on this and other issues raised by the AESO comments.

In response to the Board information request on its comments, the AESO stated that it had improperly calculated the R\(^2\) value associated with its non-zero intercept function. Further, after being in contact with DUC, the AESO decided to adopt a DUC cost function (based on work

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\(^{174}\) AESO comments on Board Staff Proposed Cost Function, November 5, 2007
DUC had performed in conjunction with the University of Calgary Math Department (UCMD))\textsuperscript{175} for the purposes of answering the Board information request.

Based on its work with the UCMD, DUC provided alternative POD cost functions based on variants of the power function.\textsuperscript{176} However, the Board is hesitant to apply more than limited weight to these proposals, given the late stage in the proceeding at which this analysis was presented and the limited opportunity of interested parties and the Board to test its validity.

Although the DUC/UCMD alternative proposal II\textsuperscript{177} reflected a comparatively high $R^2$ value (0.48), it was not without pitfalls, which included the linear estimation methodology used by DUC/UCMD and the relatively high POD charge for smaller customers that results from the proposal.

The additional DUC/UCMD analysis followed the AESO’s introduction of a possible refinement to the power function developed by Board staff to address the issues raised by the AESO regarding a zero intercept function. The AESO asserted that its proposed non-zero intercept power function exhibited a higher $R^2$ value than the power function developed by Board staff (An $R^2$ of 0.51 versus 0.49).\textsuperscript{178} However, as discussed below, having a zero intercept power function does not invalidate the use of the 48 POD power function developed by Board staff. In any event, the alternative power functions devised by DUC did not produce cost functions that are significantly different visually or mathematically from the zero-intercept power function developed by Board staff.

DUC submitted that the manner in which Excel software calculates $R^2$ values for power functions may be incorrect.\textsuperscript{179} The Board has investigated this issue and has determined that the methods used by Excel and the UCMD to calculate $R^2$ values may not be the same. However, the $R^2$ value for the Board staff non-zero intercept power function derived by DUC is not significantly different from the $R^2$ for this power function as calculated using Excel (a 0.46 $R^2$ as calculated by DUC versus 0.49 for the Excel calculation of Board staff function). The Board further notes that DUC/UCMD calculated the same non-zero intercept power function as calculated by Board staff using Excel.

The method used by DUC to develop linear approximations of the power functions sought to find the best fit for each section of its curve, and then manipulated the resulting linear functions so that they would meet at the desired breakpoints.

This contrasted with the approach adopted by Board staff, which calculated the linear functions by joining the calculated power function value for 0.10MW (the first data point in the 48 point set) to the calculated power function value for 7.5MW by way of straight line. This exercise was repeated for the 7.5MW to 17MW, 17MW to 40MW, and 40MW to 122.8MW (the last datapoint in the 48 point dataset) segments.

\begin{footnotesize}
\begin{itemize}
  \item \textsuperscript{175} BR.AESO-001(b) of Supplemental AESO IR Responses dated November 19, 2007
  \item \textsuperscript{176} DUC Reply Comments dated November 21, 2007, p. 6
  \item \textsuperscript{177} DUC submission dated November 21, 2007
  \item \textsuperscript{178} AESO comment letter dated November 5, 2007
  \item \textsuperscript{179} DUC submission dated November 21, 2007
\end{itemize}
\end{footnotesize}
The Board has reviewed the DUC approach for creating a linear estimate of its power function.\textsuperscript{180} The Board considers that Board staff’s linear approximation method has the advantage of going through the power function at chosen breakpoints.

With respect to the determination of breakpoints, the Board considers that a key advantage of creating a linear approximation to an underlying non-linear function, rather than deeming a linear function to be the underlying linear function, is that the POD cost function does not change with changes to the specific breakpoints. For example, if, as recommended by the AESO, a linear function based on the methodology proposed by the AESO in argument, the 30 greenfield dataset is used as the basis of the POD cost function, and an additional tier is added (commencing at a deemed breakpoint of 50 MW), the slope beyond that breakpoint results in a POD cost at 50 MWs. This cost is $1.024 million higher than the estimated POD cost at 50 MW under the same methodology when a breakpoint at 40 MW is selected.\textsuperscript{181} As illustrated in Table 6 below, the difference between the POD cost function produced with a 50 MW, rather than a 40 MW breakpoint remains substantial as the size of the POD increases.

| Table 6. Comparison of Impact of 40 MW and 50 MW Breakpoints Under AESO Method |
|-----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
|                 | 50 MW          | 60 MW          | 70 MW          | 80 MW          | 90 MW          | 100 MW         | 110 MW         | 120 MW         |
| Diff ($ millions) | 1.024          | 0.978          | 0.932          | 0.886          | 0.840          | 0.794          | 0.748          | 0.702          |

Source: Derived by Board from Logarithmic Function described at p. 76 of AESO Argument

The AESO asserted that a 50 MW breakpoint reflects physical changes in the transmission system,\textsuperscript{182} for example due to the tendency for multiple transformers to be installed, and should be reflected in the POD cost function. However, the AESO’s assertion that the economic or physical configuration of a POD typically changes at 50 MW was not substantiated. It also conflicts with the AESO’s evidence in the AESO’s 2005-2006 GTA and other evidence in this proceeding. Decision 2005-096 found, on the basis of the AESO’s rebuttal evidence filed in that proceeding, the cost of an interconnection using a configuration with two smaller capacity transformers could be more efficient or cost effective than an interconnection devised using a single large capacity transformer.\textsuperscript{183} As such, the suggestion that multiple transformers will be used as the size of a POD increases beyond 50 MWs appears to be in conflict with the AESO evidence relied on by the Board in Decision 2005-096. The Board also takes note of the evidence provided by Mr. Chesterman, witness for DUC, that single large transformers have been proposed by the AESO in recent interconnection projects for very large PODs.\textsuperscript{184}

\textsuperscript{180} DUC submission dated November 21, 2007
\textsuperscript{181} AESO argument, pp. 76-77. For levels above 50 MW, the AESO determined a proposed slope of $47,000 per MW by measuring the rise over run between the POD cost derived from a logarithmic function on a subset of the TCCS measured at 125 MW and 50 MW. Using that methodology and a breakpoint of 40 MW, rather than 50 MW, the slope of the additional tier of the AESO’s proposed function increases to approximately $51,590 per MW above 40 MWs.
\textsuperscript{182} AESO Argument, p. 77
\textsuperscript{183} Decision 2005-096, p. 53
\textsuperscript{184} Tr. Vol. 6, p. 1338
Considering the impact of the choice of specific breakpoints under the AESO’s proposed approach and the lack of substantiation of the assertion that 50 MW represents a significant dividing line in the configuration of typical PODs, the Board does not consider that the AESO has provided any persuasive evidence that the 50 MW capacity level has a significance that warrants its selection as a breakpoint under the AESO’s proposed approach.

The AESO also suggested that the 7.5 MW capacity level may represent breakpoint where the physical characteristics of a typical POD causes costs to change. The Board understands that the AESO selected the 7.5 MW breakpoint on the basis that it represented the lowest data point available within the greenfield dataset. The assertion that physical characteristics of a POD change at 7.5 MW was not substantiated. The Board agrees with the PPGA that a 7.5 MW breakpoint has not been demonstrated to represent any meaningful physical characteristics, and is arbitrary.

In contrast to the AESO’s proposed approach, the method developed by Board staff to create a simplified linear approximation of an underlying non-linear POD cost function does not have the same potential to create significant and arbitrary changes in the POD cost function with changes in specific breakpoints. Under the approach developed by Board staff, the breakpoint for the linear approximation only means that at selected breakpoints, the linear approximation function produces the same POD cost as the underlying non-linear POD cost function. Conversely, due to the shape of the power function, at any other point, the linear approximation falls below the POD cost function. Thus, while the approximation is improved by selecting more breakpoints, the POD cost function developed by Board staff is continuous and does not require breakpoints to be selected to correspond with specifically identified physical characteristics of PODs.

The Board considers that the POD cost functions developed by DUC and by Board staff satisfy the first three Bonbright principles set forth in section 4 of this Decision (recovery of revenue requirement, providing appropriate price signals, and fairness, objectivity and equity). However, the DUC and Board staff POD cost functions can be distinguished on the basis of the secondary criteria of rate stability and predictability. As pointed out in the AESO’s reply comments, the cost function recommended by DUC results in a shifting of costs from larger services to smaller customers. The Board observes that the proposed POD cost function developed by Board staff is not likely to result in rates that are substantially different from existing rates, thereby providing greater consistency and stability for smaller customers 1MW-5MW in size.

In light of the above, the Board finds that the linear approximation to the power function based on the POD cost function developed by Board staff, using breakpoints at 7.5 MW, 17 MW, and 40 MWs, produces an acceptable POD cost function for the purposes of the AESO’s 2007 tariff.

During the comment and reply process, numerous submissions were made regarding zero intercept and negative intercept functions. However, the highest R² proposals (the DUC proposal and the proposal developed by Board staff) have non-zero intercepts after the linear transformations.

Further, even if the underlying power function was to have a zero intercept, it has not been demonstrated that such a power function is fatally flawed.

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185 AESO reply comments dated November 26, 2007, p.3
First, the Board is not convinced that a zero intercept for a POD cost function is unrealistic or inappropriate. No explanation has been advanced in this proceeding for constructing a POD to provide a DTS capacity at a prudent cost in excess of zero for a demand of zero. In addition, another important characteristic of the power function is a high slope at very low values of x that flattens out quite quickly. As a result, the Board considers that for all but exceptionally low values of DTS contract capacity, the power function based on the POD cost function developed by Board staff provides a cost estimate that is both reasonable and similar to the cost estimates produced by functional forms that include a minimum intercept.

In this regard, 0.1 MW is the lowest DTS value in the 13 TCCS data points provided by the AESO. When a DTS contract capacity of 0.1 MW is evaluated using the POD cost function developed by Board staff, the resulting POD cost is $944,066.77. This does not significantly differ from the estimated POD cost of $1,011,100 for a DTS capacity of 0.1 MW that results from the POD cost function proposed by the AESO.  

Also notable from the small POD data provided by the AESO is that the lowest POD cost in the 13 POD TCCS dataset ($994,907) occurs at a DTS capacity of 1.46 MW. From the 13 POD small projects TCCS dataset, this is the sole data point used by the AESO to develop the first tier of its proposed POD cost function. In light of this minimum POD cost of $994,907, it is notable that the power function based POD cost function developed by Board staff will generate a POD cost at or above $994,907 for any value of DTS capacity greater than 0.115 MW. Thus, the Board considers that the use of a zero intercept power function is not biased towards estimating very low POD costs for very low capacity PODs since, if anything, the results described above indicate that the POD cost function developed by Board staff is more likely to slightly overstate, rather than understate, POD costs for very low DTS capacity PODs.

In light of the above, the Board considers that any concerns that that the POD cost function developed by Board staff may not properly represent the minimum cost of a POD only arise in relation to extremely small DTS values that have not been shown to generally arise in practice. As such, the Board considers that any theoretical issues related to the properties of the power function at zero and other extremely low values of DTS capacity are of much less concern than the potential for distortions to be caused by using a functional forms that do not reflect the evidence accepted by the Board in section 5.7.4 that economies of scale generally cause POD costs to rise at a decreasing rate with increases in contract capacity.

For these reasons, the Board finds that the POD cost function developed by Board staff that was released for comment on October 25, 2007 is the function to be used by the AESO.

The Board directs the AESO to reflect the Board approved linear POD cost function in the AESO refiling as noted below:

\[
Y = 0.894 \text{ million} + 0.503 \text{ million/MW for the first 7.5MW} + \\
0.174 \text{ million/MW for the next 9.5MW} + \\
0.102 \text{ million/MW for the next 23MW} + \\
0.054 \text{ million/MW for all MW above 40.0MW.}
\]

\[186 \quad \$1,011,100 = 947,000 + (.1) \times 621,000. \text{ Figures obtained from AESO argument, page 78}\]
The Board will address the function multiplier to be applied to this cost function to develop the Board approved investment formula in section 8.1.2.2 of this Decision.

5.7.8 Other POD Charge Related Issues

Certain parties raised other issues relating to the POD charge. These issues included additional cost causation design credits, the treatment of radial versus looped line costs in the POD cost function, and the treatment of TFO O&M costs in the POD cost function. These issues are addressed below.

5.7.8.1 Additional Cost Causation Design Credits

PPGA submitted that regardless of the POD established by the Board (including PPGAs proposed POD charge of $4725/month plus $1447/MW/month), the POD charge should be further adjusted to apply credits to small customers to reflect the AESO’s policy of standardizing facilities to a minimum of 138 kV. In addition, PPGA, recommended adjustments reflecting the AESO’s classification of transformer high-side breaker costs as local costs (rather than POD costs).  

As illustrated in a table provided in its evidence, PPGA submitted that a 69kV interconnection is approximately 9% less expensive than a similarly sized 138 kV interconnection, primarily as a result of the lower cost of a 69kV transformer. Accordingly, PPGA submitted at a 9% credit or reduction should be applied to the fixed monthly charge portion of the POD charge adopted by the Board. To retain revenue neutrality, PPGA proposed that this credit should be funded by a higher POD charge to loads greater than 20 MW.

With respect to breaker costs on the high voltage side of the transformer, PPGA submitted that high-side breaker costs represent 2% of the cost of an average POD connection. Accordingly, PPGA submitted that 2% of POD costs should be moved from POD costs to the local system cost category. To the extent the Board were to accept PPGA’s proposal to account for high-side breaker costs, PPGA submitted that the POD cost revenue requirement should be reduced by $3.6 million.

CCA/PICA submitted that the economics of a PPGA member’s choice to connect at the Disco rather than through a direct transmission connection is part of the risk assumed by the customer. Accordingly, CCA/PICA submitted that it would not be appropriate to provide a credit for smaller PODs connecting to the transmission system. CCA/PICA suggested that the PPGA recommendation to move high side breaker costs from the POD cost to the local cost category would be appropriate to the extent that the high side breaker equipment forms part of the network or looped system, which is part of the local system.

As discussed in section 2 above, recognizing different operational circumstances and their cost implications does not, in itself, contravene subsection 30(3) of the EUA. However, the Board is

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187 Ex. 239, PPGA Evidence, p. 18
188 Ex. 239, PPGA Evidence, p. 18
189 Ex. 239, PPGA Evidence, p. 19
not persuaded that PPGA’s proposed credit to small customers, to reflect the differential in costs between 69kV and 138 kV interconnection facilities is warranted.

Within the context of a postage stamp rate design, a certain amount of averaging is present. The Board considers that the DTS rate should show a high degree of uniformity across AESO customers and therefore, proposed differentiations from the uniform rate should be subject to significant scrutiny by the Board before any such proposal is granted. The Board also agrees with CCA/PICA that the economic impact of a choice to connect to the transmission system rather than to a Disco is a risk assumed by the customer.

The Board agrees with the AESO that the nature of the service provided to AESO customers that sign up for system access service is not determined by the voltage level of the interconnection facilities.

PPGA’s proposal to classify breakers on the high voltage side of a transformer as local system costs (rather than POD costs) relates to functionalization as between local and POD costs, rather than to the design of the POD charge itself. The Board agrees with the AESO that no adjustment to the functionalization of local and POD costs is necessary to account for high-side breaker costs. As discussed in the TCCU, the functionalization of TFO cost to POD costs includes the cost of radial lines. Given that radial transmission lines will include facilities located on the high-voltage side of the transformer, it follows that breakers that happen to be located on the high-voltage side of the transformer would be functionalized as POD costs.

Given the foregoing, the Board does not accept the PPGAs proposal to reduce POD costs by $3.6 million to reflect the functionalization of high-side breaker costs from POD to local.

5.7.8.2 Treatment of Radial vs. Looped Line Costs in POD Cost Function

CCA/PICA expressed concern that by including full radial line costs in its POD cost function, the AESO has overstated the level of the first block of variable demand component of its proposed POD cost function. In particular, CCA/PICA submitted that because only 34% of PODs are radially fed while the remainder of the PODs are looped, radial line costs are not applicable for 66% of substations. To address its concern that the AESO’s proposed POD cost function may reflect the cost of looped transmission lines, CCA/PICA proposed adjustments to POD cost functions used for both the POD charge and the maximum investment function.

CCA/PICA argued that for the purposes of developing its cost functions, the AESO considered substation and radial line costs together in its regression analysis of 30 greenfield projects. In contrast, CCA/PICA submitted that its evidence considered the average cost of lines separately from the substation function when developing the POD cost function and investment function. CCA/PICA further submitted that as there is no relationship between the length of a radial line and the size of a POD, it would be appropriate to consider radial line costs and substation costs separately, both for POD cost and investment function purposes.

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190 Ex. 012, TCCU, page 47
191 Ex. 225, CCA/PICA Evidence, p. 8 citing Application Appendix C (Ex. 012), p. 43
192 Ex. 225, CCA/PICA Evidence, pp. 8-10
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 though 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.\textsuperscript{193}

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 classification.

\textsuperscript{193} Decision 2005-096, p. 23
Secondly, given that additional system costs incurred to accommodate service over a merchant intertie fall within section 27 of the 2007 Transmission Regulation, the Board finds that insufficient evidence was offered in this proceeding to allow the Board to determine whether the proposed MTS rate is in compliance with section 27. Accordingly, the Board is unable to approve this rate at this time.

The Board acknowledges that the TCE witness panel questioned the likelihood of customers entering contracts to induce additional firm capacity to or from an intertie since before an intertie is built, the benefits of firm import or export transactions cannot be used to offset the substantial cost of contracting for firm MTS service. However, the Board is concerned that the potential for customers to contract for firm MTS service to induce or advance additional deep system capacity may nevertheless exist. This potential is of sufficient concern that the Board is not prepared to approve the rate MTS at this time.

7.3.1.2 Merchant Opportunity Service Rates (MOS 1 Hour and MOS 1 Month)

The AESO proposed that its MOS 1 Hour and MOS 1 Month rates would generally reflect the cost allocation principles used by the AESO to develop its proposed XOS 1 Hour and XOS 1 Month rates. The main exception was that the AESO proposed that its MOS rates should not include an allocation of costs related to the existing interties, since the existing intertie facilities would not be used by exporters using a merchant line to access other markets.

For energy either generated or consumed in Alberta, the Board agrees that customers using a newly constructed merchant intertie would not require the use of the existing Alberta-British Columbia or Alberta-Saskatchewan interties. This indicates that the minimum charge component of the rate (based on the incremental variable cost associated with providing the service) would be equal to or lower than the corresponding XOS rate minimum charge. However, the Board finds that no evidence indicated that the value of the proposed merchant opportunity service (MOS) is less than the value of export opportunity service (XOS). Accordingly, the Board finds that the value of service based rate for MOS 1 Hour and MOS 1 Month is $3.98/MWh and $4.36/MWh respectively, consistent with the Boards findings in section 7.2.1.

8 TERMS AND CONDITIONS OF SERVICE

8.1 Customer Contribution Policy

8.1.1 Interconnection Project Cost Function

In Decision 2005-096, the AESO was directed to undertake further research to devise a more comprehensive investment function proposal which avoids the concerns expressed by the Board in that decision and which reflects the design principles described by the Board in that Decision. A proposal based on this research was to be presented in the AESO’s 2008 GTA.

In the Application, the AESO noted that following extensive debate during the 2005/2006 GTA, the Board in Decision 2005-096 amended the maximum local investment formula to provide a

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310 Tr. Vol. 6, pp. 1209-1210
311 Ex. 005, Section 4 of the Application, p. 50 of 53, lines 13-19
312 Decision 2005-96, pp. 57-58 (Direction 13A)
minimum investment allowance of $2.5 million plus an additional allowance of $100,000 per MW of project capacity.\textsuperscript{313}

As a result of feedback obtained during stakeholder consultations, the AESO undertook to revise the investment allowances under the contribution earlier than the 2008 GTA. It is apparent that the AESO encountered obstacles related to the limited amount of available POD cost data in its efforts to gather the data required to fulfill the Board’s direction to develop a cost based interconnection project cost function. The Board wishes to acknowledge the AESO’s diligence in complying with the Board’s direction. The Board confirms that the AESO has complied with the Board’s Direction 13A from Decision 2005-096.

The AESO used the same cost function both to determine a proposed investment function under the customer contribution policy and to design the POD charge component of Rate DTS. Accordingly, to the extent that parties made submissions related to determining a POD cost function for POD charge purposes, such submissions have also been taken into account by the Board, as appropriate, in its assessment of the appropriate POD cost function for customer contribution policy purposes.

As discussed in section 5.7.3 of this Decision, the Board has determined that it is appropriate that the same underlying average cost function be used for both POD charge determination and contribution policy investment allowance purposes.

However, in section 5.7.7 of this Decision, the Board has not approved the POD cost function proposed by the AESO. Accordingly, for greater certainty, the Board confirms that the approved POD cost function set out in section 5.7.7 of this Decision is to be used as the basis for the maximum investment function. The Board discusses the additional steps required to convert the approved POD cost function into the approved maximum investment allowance function.

\textbf{8.1.2 Determination of Maximum Investment Function}

Article 9.6 of the AESO’s proposed T&Cs describes the determination of the customer contribution for a load interconnection project. Within Article 9.6, the major determinant of the customer contribution is the maximum local investment (maximum investment). In section 6.5.3 of the Application, the AESO discussed its efforts to comply with Directive 13 of Decision 2005-096.

The AESO considered that Directive 13A required the multiplier of its proposed interconnection project cost function to be consistent with a maximum investment function such that 80% of projects do not pay a contribution. Based on an analysis of sample POD cost data from its analysis of current projects sample, the AESO determined that applying a multiplier of 1.15149 to its proposed interconnection project cost function would result in 24 of 30, or 80%, of projects being fully covered by the resulting maximum investment function.

The AESO noted that the 80/20 criterion established by its predecessor was originally approved by the Board in Decision 2001-6. It further submitted that using this criterion assists in harmonizing the AESO’s contribution polices with those of the Discos and helps to preserve the

\textsuperscript{313} Exhibit 007, Section 6.3.2 of the Application
balance between the need of new customers for service and for service without subsidization from existing customers. Additionally, the AESO submitted that the 80/20 criterion supported the principles that most new customers would not see a different cost of system connection than existing customers, and existing customers should not bear any extraordinary costs of system expansion.

In argument, the AESO noted that while its proposed POD cost function had changed from the POD cost function it initially proposed in the Application, its proposed multiplier of 1.15149 did not change as a result of the revisions to the cost function since the multiplier still resulted in 80% the 30 greenfield projects being fully covered by the resulting maximum investment function.

The AESO further noted that its proposed application of the multiplier was not debated by any party during the hearing.

The Board considers that before ruling on the appropriate multiplier to be used to set maximum investment allowances under the customer contribution policy, it is first necessary to address the issue of whether a so called “80/20 Rule” should apply.

### 8.1.2.1 Application of “80/20 Rule”

As discussed in section 8.1.1 above, Direction 13A from Decision 2005-096 required the AESO to perform research leading to the development of a function describing the relationship between interconnection project capacity and average cost. Direction 13A also instructed the AESO to perform research into a multiplier of the AESO’s proposed average interconnection cost function that would provide a degree of tolerance above the average interconnection cost function. Consistent with the Board’s finding in section 8.1.1 above that the AESO’s interconnection project cost research complied with the requirements of Direction 13A, the Board considers that the AESO’s research into the development of an appropriate multiplier of the average interconnection project cost has complied with the Board’s direction.

It appears that Direction 13A has been interpreted by the AESO and some other parties as a general endorsement for the continuation of a so-called “80/20 Rule” previously applied to the AESO’s predecessor.\(^\text{314}\)

However, the direction to devise a multiplier such that 80% of projects of the project fall under the resulting maximum investment function represented no more than a direction to conduct a one-time study. The mention of 80% in the direction should not have been interpreted as a general endorsement of an 80/20 rule as a guiding principle, nor did it require that the 80% threshold be used by the Board in determining an appropriate multiplier for the maximum investment function for the 2007 tariff.

The underlying principles intended to govern the design of AESO and utility contribution policies generally were discussed in some detail in sections 6.1.1 and 6.1.4 of Decision 2005-096. Included in the most important considerations set out in that decision are the following:

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\(^{314}\) See Ex. 007, p. 18; Ex. 015, p. 26; AESO Argument, p. 43, p. 44, p. 79, p. 81, AESO Reply, p. 34; DUC Evidence (Ex. 229, p. 30); TCE Reply Argument, p. 11
• the underlying purpose of the contribution policy is to send economic signals to AESO customers when considering alternatives for siting their interconnecting loads;\textsuperscript{315}

• an excessive investment allowance could provide incentives for customers to pursue higher standards of interconnection facilities than required and justify doing so on the basis that the cost of the higher standard facilities would not exceed the permitted investment allowance;\textsuperscript{316}

• because the incremental revenue approach may place undue upward pressure on rates, maximum investment allowances should be at a level below a level representing the incremental revenues expected to arise from the interconnection of a new customer;\textsuperscript{317}

• investment allowances should be set with regard to the anticipated costs of establishing an interconnection reflecting acceptable standards of functionality and service established by the AESO;\textsuperscript{318}

• interconnection facility service characteristics and standards of functionality may change over time.\textsuperscript{319}

These considerations can not be assumed to be automatically addressed solely by applying an 80/20 rule test to a proposed maximum investment function.

The Board considers the following passage from Decision 2005-096 to be instructive:

The Board considers that the underlying rationale for the consideration of revenues in the context of a contribution investment policy relates to the manner in which a new customer interconnection may benefit existing customers through a broader sharing of embedded system costs. In this context, the incremental transmission revenue generated by connecting the new customer is also the maximum level of the “willingness to pay” of existing customers. Furthermore, since the Board considers that a new customer may normally be presumed to be seeking an interconnection in order to obtain the benefits of electrical service rather than an investment allowance per se, the Board considers that the new customer should be provided the incentive to commit an investment as long as the costs of any required interconnection facilities are offset. Thus, there is the potential risk of creating a substantial difference between the respective willingness to pay of the new customers and that of existing customers. The difficulty in creating a utility investment policy is to determine how to design a maximum investment allowance function that will fall at a reasonable level within this range.\textsuperscript{320}

The key concept described in the above passage is that the level of investment allowance should be targeted to fall somewhere in a range between the bookends of: (1) making the connecting customers pay for the full cost of a new interconnection and (2) providing a full contribution credit to reflect the benefit of embedded system cost sharing new AESO customer can provide to existing customers.

\textsuperscript{315} Decision 2005-096, p. 43
\textsuperscript{316} Decision 2005-096, p. 44
\textsuperscript{317} Decision 2005-096, p. 44
\textsuperscript{318} Decision 2005-096, p. 44
\textsuperscript{319} Decision 2005-096, p. 44
\textsuperscript{320} Decision 2005-096, p. 56
Setting the appropriate level for the maximum investment allowance is a balancing act. On one hand, it is desirable that the level of required customer contributions not dissuade customers from connecting to the system. On the other hand, the level of the investment allowance offered should ideally not be higher than most customers need to be incented to connect. However, as a result of additional considerations presented during the proceeding, the Board is no longer persuaded that, in and of itself, an 80/20 rule achieves the proper balance.

One piece of new information arises from section 6.5.3 of the Application regarding the way in which customer contribution levels have changed over time. This section highlighted the differences between the required customer contribution level for similar projects under contribution polices in effect in the years between 1999 and 2005 as compared to the contribution level required under the contribution policy approved in Decision 2005-096.

If the message that was intended to be conveyed in section 6.5.3 of the Application was that the level of the maximum investment allowance should be raised (because the contribution policy approved in Decision 2005-096 required significantly higher customer contributions than did previously approved contribution policies), the Board does not agree with this conclusion. The interconnection project queue appears to have grown rather than declined under the contribution policy prescribed in Decision 2005-096. The Board finds this to be clear evidence that having a maximum investment allowance which provided that more than 20% of interconnection projects must pay some contribution has not dissuaded AESO customers from proposing a greater number of new interconnections than can be immediately accommodated by the AESO and the TFOs. The Board therefore concludes that the lower investment allowance permitted in Decision 2005-096 did not discourage investment.

Another significant concern that the Board has with an 80/20 rule is that the application of such an 80/20 rule may become circular or self fulfilling, in that higher cost projects may trigger increases in the multiplier. As a result, the Board is concerned that to perpetuate an 80/20 rule may undermine the principle that the level of the maximum investment function provides an economic signal to AESO customers. For example, in Decision 2005-096 the Board expressed a similar concern in the context of its proposed pre-paid O&M charge:

> The Board is particularly concerned that, in applying the proposed DTS customer pre-paid O&M 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.\(^{323}\)

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\(^{321}\) Ex. 007, pp. 28-29

\(^{322}\) The AESO’s response to undertaking 7 (Ex. H-023, p. 3 of 5) indicates that the load interconnection project queue had grown to 69 projects as May 18, 2007, which exceeds the total number of projects (59) reported in Attachment BR.AESO-016 (Ex. 092) over the period 1999-2005.

\(^{323}\) Decision 2005-096, pp 68-69
The AESO discussed the Board’s concern in that context:

The Board noted above that it was inappropriate for the AESO to presume that the combination of standard facility costs and the O&M charge would be covered by the investment level. The AESO acknowledges the Board’s position but suggests that such a principle only applies if the customer contribution policy has a set investment level. If the investment level was set at a specific value and was not based upon the number of projects that are not required to pay a contribution – which is not how the current and proposed investment policies are structured (i.e. 80% of projects are not to pay a contribution per Board Directive 13A in Decision 2005-056, and further described below) – the number of customers that would be required to pay a contribution would increase. But as noted the investment level is required to meet the criterion that 80% of projects do not pay a contribution. If the O&M charge was to continue to be applied to standard facilities, the cost function would increase but so would the investment level function so as to maintain the target of 80% of projects not having to pay a customer contribution. As such, the AESO is of the view that the benefit to economic siting and facility development originally intended by the Board by including the O&M charge is very limited. (Emphasis added).\(^324\)

The Board considers that the concern discussed by the AESO in the emphasized portion of the passage above applies to all interconnection project costs. That is, if increasing interconnection project costs are, in the normal course, constantly updated within the maximum investment allowance to reflect an 80/20 rule, the ability of the maximum investment function to provide an economic signal may be significantly diminished over time.

Accordingly, while the Board has assessed how the 80% of projects threshold specified in Directive 13A impacts the multiplier and resulting maximum investment allowance, for the reasons discussed above, the Board’s statements in Decision 2005-096 do not constitute an endorsement by the Board of an 80/20 rule. Rather, the Board’s statements in that decision were intended simply to direct the AESO to conduct a study to determine a multiplier. A determination would then be made on whether or not use of that multiplier was warranted.

The Board provides its analysis and findings on the determination of an appropriate 2007 tariff investment function multiplier in the immediately following section.

8.1.2.2 Appropriate Multiplier for 2007 Tariff Maximum Investment Function

In determining the appropriate multiplier to apply to the approved POD cost function, the Board evaluated a rounded off version of the AESO proposed multiplier of 1.15149, namely 1.15, and developed cost functions in 0.05 multiplier increments until such time as 80% of the 48 point dataset projects would receive full investment. 80% of the 48 point TFO project cost data points received full investment using a multiplier of 1.35 applied to the Board approved cost function. A graph of the investment functions based on this data, including the AESO’s final proposed investment function, is shown below:

\(^{324}\) Ex. 007, p. 14 of 47
In determining the impact that outlying data points have on the level of the multiplier required to satisfy an 80/20 rule, the Board analyzed the 48 point dataset to determine how many data points would receive at least 80% investment using the rounded version (1.15) of the AESO’s proposed multiplier of 1.15149.

A multiplier of 1.15 results in 27 data points receiving full investment, six data points receiving over 90% investment, and another five data points receiving at least 80% investment. As such, 38 out of 48 data points, or 79.2% of the data points receive at least 80% investment and the majority of these points receive full investment.

The above graph shows the raw data points that received at least 80% investment using the Board approved cost function and a 1.15 multiplier to determine the maximum investment function. These data points are marked with a + sign and noted in the graph legend.

The Board considers that using a 1.15 multiplier is more than adequate in providing a sufficient investment level of investment based on the 48 point sample dataset. This multiplier works just as well if a 30 point “greenfield” subset of the 48 point dataset is considered. Further, the 1.15 multiplier was also proposed by the AESO even after it modified its cost function in argument.

As the AESO obtains new TFO project cost information in the future, the 48 point dataset may be expanded and cost functions further analyzed. The key though is that any future changes to the investment function be based on actual project costs, without the potential circular bias that implementing and maintaining an 80/20 rule may impose. The Board observes that the 1.15 multiplier, when applied to the Board approved cost function, achieves a result that is not substantially different than the result that would be produced by application of an 80/20 rule. To
be clear, an 80/20 rule is not to be relied on in future when amending the maximum investment policy.

For all of the above reasons, the Board approves a multiplier of 1.15 to be applied to the cost function approved in section 5.7.7 of this Decision to determine the maximum investment function.

The resulting Board approved maximum investment function is as follows:

\[
Y = \ 1.028 \text{ million} + 0.578 \text{ million/MW for the first } 7.5\text{MW} + \\
0.200 \text{ million/MW for the next 9.5MW} + \\
0.118 \text{ million/MW for the next 23MW} + \\
0.062 \text{ million/MW for all MW above 40.0MW}
\]

The cost function approved in section 5.7.7 of this Decision entails rounding such that a pure application of the 1.15 multiplier may result in a difference in the third decimal in the above function. The function above has been determined by multiplying the unrounded Board approved cost function by 1.15, and then round the values to three decimals, and is the function to be implemented by the AESO.

### 8.1.3 Inflation Adjustments to Maximum Investment Function

TCE argued that although the AESO witness panel had confirmed that the investment levels set out in Article 9.6 were designed so that about 20% of DTS customers who attach to the system will make a contribution,\(^{325}\) it also confirmed that as the costs of projects rises overtime, on average more than 20% of customers would be required to make a contribution.\(^{326}\) In recognition of the effect of inflation, TCE submitted that the Board should direct the AESO to amend Article 9.6 of the T&Cs to include a project inflation factor such as the Consumer Price Index (CPI) or another widely recognized factor.

With respect to TCE’s proposal, the AESO noted that while it had agreed that a project inflation factor could be considered if an appropriate index could be used, the contribution policy in place at a given time should provide a price signal that reflects the current economic situation. The AESO submitted that the contribution policy should not be static, but should rather be revisited as more data becomes available.

DUC argued that the maximum investment allowance levels provided under the AESO’s contribution policy should be increased by 5% to reflect inflation over the period of late 2007, 2008, and 2009 that the AESO’s 2007 tariff may be in effect.

The AESO replied that the 5% increase proposed by DUC did not appear to be based on any trending analysis or inflationary economic reporting. The AESO further noted that an inflation rate based on Alberta CPI approved by the Board in other decisions was used to update POD cost data within the customer contribution study provided as Appendix F to the Application.\(^{327}\)

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\(^{325}\) Tr. Vol. 2, p. 501, referenced at p. 64 of TCE Argument

\(^{326}\) Tr. Vol. 2, p. 502, referenced at p. 64 of TCE Argument

\(^{327}\) Ex. 015, referenced at p. 34 of AESO Reply
As discussed in section 8.1.2.1 above, the Board has not endorsed the so-called 80/20 rule. Accordingly, the Board rejects TCE’s proposition that that Article 9.6 should be amended to include an inflation allowance to maintain adherence to an 80/20 criterion.

The Board agrees with the AESO that DUC’s proposal for a 5% inflation adjustment is not necessary in light of consideration of the inflation adjustments applied to POD cost data as part of the AESO’s customer contribution study. The Board considers that as the average POD cost function adopted by the Board in this Decision already reflects inflation adjusted POD cost data, no further adjustments are necessary to bring the data up to date. The Board also agrees with the AESO that little basis was provided by DUC to support the selection of 5% as an appropriate inflation adjustment.

The Board disagrees with DUC’s view that an additional inflation adjustment is necessary to reflect the anticipated continuation of the 2007 AESO tariff into 2008 and 2009. The maximum investment function set out in section 8.1.2.2 of this Decision is significantly above the maximum investment allowance set out in Decision 2005-096. The Board considers that the increase in the level of the maximum investment allowances, particularly for AESO customers with a large contract capacity, offsets the impact of inflation on the cost of new interconnections.

The Board agrees with the AESO that that the effects of inflation on POD costs may be relevant to the reconsideration of maximum investment levels in the future. Such consideration should occur, if necessary, in the context of a future GTA.

8.1.4 Applicable Tariff for Customer Contributions and Contract Capacity Increases

In section 6.5.1 of the Application, the AESO described its proposed changes to Articles 9.2, 9.7, and 9.9 of its T&Cs. The AESO noted that its practice has been to recalculate the customer contribution for an interconnection project on the basis of the tariff in effect at the time the original interconnection was constructed.

The AESO submitted that it was appropriate to revise the amounts of customer contributions based on the contribution policy in effect at the time of the original system access request because the events described in Article 9.9 and the sharing of facilities discussed in Article 9.10 of the T&Cs are largely outside the control of the customer and primarily affect the original facilities built to accommodate the original system access request. However, the AESO acknowledged that it had also encountered situations where a customer request for an increase in contract capacity required the construction of new transmission facilities to accommodate the contract capacity increase. The AESO noted that this situation was not currently explicitly addressed in the T&Cs, but that it was the AESO’s business practice to apply the approved tariff in effect at the time of project commitment to determine the customer contribution and contract term. In light of this practice, the AESO proposed updates to Article 9.2, 9.7, and 9.9 to reflect this treatment.

No parties took issue in argument or reply with these changes as proposed by the AESO. The Board has reviewed Article 9.2, Article 9.7 and Article 9.9 and approves these provisions as filed.