



June 10, 2009

Posted on AESO website

Tariff Provisions Related to Customer-Owned Substations Working Group Members
AESO Stakeholders

Dear Working Group Member:

Re: **Meeting Agenda for Tariff Provisions Related to Customer-Owned Substations Working Group**

The first meeting of the Tariff Provisions Related to Customer-Owned Substations Working Group for the AESO's 2010 tariff application is scheduled as follows:

Time: 11:30 AM to 1:30 PM
Date: Thursday, June 11, 2009
Location: Meeting Room 2506, AESO Office, 330 – 5th Avenue SW, Calgary
Refreshments: Working lunch and beverages

This working group includes the following members:

- DUC: Dale Hildebrand
- ENMAX: Andy Morgans
- IPCAA: Sheldon Fulton
- StatoilHydro: Brian Blattler
- TransCanada: Dan Levson
- UCA: Ed de Palezieux
- AESO: John Martin and 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.

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

- | | | |
|---|---|----------|
| 1 | Introductions | 11:30 AM |
| | • Please indicate which stakeholders you represent | |
| 2 | Review agenda | 11:40 AM |
| 3 | Review draft working groups terms of reference | 11:45 AM |
| | • 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 customer-owned substations** 11:50 AM
- Please review the enclosed information before the meeting, if possible:
 - (a) Discussion of primary service credit in section 5.10 (pages 63-68) of Decision 2007-106 on the AESO's 2007 General Tariff Application, released on December 21, 2007
 - (b) AESO's responses to Directions 10 and 11 in its 2007 General Tariff Application Refiling, filed on February 1, 2008
 - Is there other background that participants consider particularly relevant?
- 5 **Tariff principles for customer-owned substations** 12:00 Noon
- What principles were established in Decision 2007-106 or in other decisions?
 - Have conditions changed or is new information available such that those principles no longer apply?
 - Are there additional principles that should be added?
- 6 **Additional considerations for customer-owned substations** 12:45 PM
- What additional concerns exist for customer-owned substations?
 - Are there other approaches to addressing these concerns?
- 7 **Follow-up required for next meeting** 1:15 PM
- Summarize what tasks need to be completed before next meeting and who will complete them
- 8 **Dates and times for next meeting(s)** 1:25 PM
- 9 **Adjourn** 1:30 PM

This agenda and all other printed information related to the Tariff Provisions Related to Customer-Owned Substations 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 Raj Sharma 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

AESO 2010 Tariff Consultation Working Groups Terms of Reference

1 Purpose

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

2 Topics

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

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

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

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

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

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

- (f) **Deferral Account Riders B and C**
 - Rate design principles for deferral account riders
 - Practicality of improving allocation accuracy of deferral account riders
 - Possible integration of Riders B and C

- (g) **Tariff Changes Related to Transition of Authoritative Documents (TOAD)**
- Provisions that could be moved from tariff to other authoritative documents (such as technical standards or ISO Rules)
 - Common provisions that could be standardized and consolidated
 - Dispersed information that could be consolidated
- (h) **Amortized Customer Contribution Option and Other Contribution Provisions**
- Potential changes to AESO standard facilities definition
 - Potential provisions for amortized customer contribution option
 - Assessment of credit-worthiness and mitigation of risk of default
- (i) **Tariff Provisions Related to Customer-Owned Substations**
- Principles for tariff provisions at customer-owned substations
 - Assessment of Primary Service Credit and associated investment factor
 - Application of substation fraction at customer-owned substations

3 Working Group Members

The Working Groups will consist of AESO stakeholders and AESO employees with interest, expertise, or both in the specific topic being examined in each Working Group.

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

4 Duration

Each Working Group will be active from May 1, 2009 to no later than mid-July 2009.

- A Working Group may conclude activities earlier if no further review of the topic would be helpful to the AESO's 2010 tariff application.
- A Working Group may also continue activities for a longer period if an extension is required to effectively satisfy its purpose.

5 Scope and Duties

Working Groups will review and discuss options and alternatives for proposals being considered for inclusion in the AESO's 2010 tariff application. Working Groups are not decision-making bodies. Consultation within Working Groups will not replace general stakeholder consultation. The AESO will consider consultation within the Working Groups in the context of its broader stakeholder consultation.

- (a) Working Groups will determine their own meeting dates and times. Meetings are expected to occur about every two weeks, for one to two hours. Meeting agendas will be prepared and communicated in advance as much as practical. Members may participate in meetings via conference call. A Working Group will generally be coordinated and chaired by an AESO employee. Meetings may be held at the office of the AESO or of other Working Group participants.
- (b) Working Group members are expected to dedicate appropriate time to actively participate in Working Group meetings, to review material prior to meetings, and to address questions raised and issues identified following the meetings. Working Group members may assign work to others within their organizations with appropriate technical or regulatory expertise on the topic.
- (c) Working Group members are expected to engage in informal open discussion on a “without prejudice” basis. Although discussion in Working Groups will not be presented as evidence in the AESO’s tariff application proceeding, the AESO and participants may refer in their respective evidence to any conclusions they reach as a result of Working Group discussion. A participant or representative on any Working Group will not be precluded from participating in the AESO’s tariff application proceeding before the AUC. Neither stakeholders nor the AESO will be limited in any way from expressing views that may differ from those expressed in the Working Group. However, all participants are expected to engage in meaningful and transparent dialogue in the Working Groups.
- (d) The activities of the Working Groups and related written documents will be communicated to stakeholders through postings on the AESO website, as appropriate. However, minutes of discussion and transcripts of conversations will not generally be prepared. All material will be assumed to be non-confidential unless identified otherwise. All such material will be available on the AESO website at www.aeso.ca by following the path Tariff ► Current Consultations ► 2010 Tariff. All stakeholders will generally have opportunity to comment on the material posted, as part of comment processes in the AESO’s general stakeholder consultation.
- (e) Working Group conclusions will be considered by the AESO in developing proposals for its 2010 tariff application. The AESO’s 2010 tariff application will reflect decisions consistent with legislation, policy, and the AESO’s mandate, considering the input and advice provided by the Working Groups. The rationale for the AESO’s proposals will be included in the tariff application.

6 Deliverables

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

- (a) Advice and expert comments on specific topics being considered as part of the AESO’s 2010 tariff application.
- (b) Suggestions to improve the studies, analysis, rates, and terms and conditions that will comprise the AESO’s 2010 tariff application.

- (c) Identification of legislation, policy, prior regulatory decisions, principles, precedent, and practices that are relevant to the topic being examined by the Working Group.

7 Principles

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

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

8 Expenses

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

9 Recent AESO Tariff Decisions

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

- AUC Decision 2008-037: AESO 2007 General Tariff Application Refiling (released on May 8, 2008)
- EUB Decision 2007-106: AESO 2007 General Tariff Application (released on December 21, 2007)
- EUB Decision 2005-132: AESO Review and Variation of Customer Related POD Charge (released on December 6, 2005)
- EUB Decision 2005-131: AESO Refiling of 2005/2006 General Tariff Application per Decision 2005-096 (released on December 6, 2005)
- EUB Decision 2005-096: AESO 2005/2006 General Tariff Application (released on August 28, 2005)

Therefore, the Board directs the AESO to prepare bill impacts that compare the bills which result from the directions in this Decision to the current Board approved tariff. The bill comparison will include all components of a customer's bill, including commodity costs, similar in format to Board information request BR-AESO-003.²⁰² The pool price assumed for the commodity charge is to be the same for both periods so that the comparison isolates the increase attributable to transmission costs only. All other assumptions used in developing the results and the impact of those assumptions are to be included in the analysis. For any POD receiving an increase of greater than 10% (in comparison to the 2006 tariff), the Board directs the AESO to provide the nature of the customers served by each POD (whether Disco, direct connect, or a Disco customer on a flow through rate), the total dollar impact to the POD and the total amount it would cost to subsidize all such PODs down to the 10% increase level.

5.10 Primary Service Credit

5.10.1 PSC Methodology

In Decision 2005-096 the Board explained the rationale for the Primary Service Credit (PSC) as follows:

The Board understands the rationale for the payment of the credit is that the credit reflects the fact that DTS customers have paid for the full cost of transformation facilities at their site. As DTS customers, they have signed a contract with the AESO for service and are obligated to pay fixed DTS charges related to their contract capacity. Included in this fixed charge is payment to the AESO for the cost of transformation equipment that the system would usually pay for and provide to the customer. As the customer has already paid for the full cost of transformation equipment at their site, it is not necessary for the system to invest in such facilities.

Consequently, if no credit were available to these customers they would be in a position of paying twice for one set of transformation assets – once when the customer installed and paid for the assets, and a second time when paying their fixed DTS charges each month. The Board does not consider it reasonable to compel a customer to pay twice for one set of assets. It follows that a credit should be available to such customers to ensure that they do not pay twice. The Board considers this to be just and reasonable.²⁰³

The DTS rate, and the POD charge component of it, are postage stamp in nature. As such, the purpose of the PSC is not to refund to a specific customer exactly what it has paid for a particular asset but rather to provide a credit representing a portion of the DTS charge that represents payment to the AESO for the cost of transformation equipment that the system would usually pay for, but that customers have already paid for themselves.

In the Application, the AESO has proposed to change the structure of the PSC, from the \$/MW basis approved in Decision 2005-096,²⁰⁴ to align it with the POD charge component of the DTS rate. It proposed that the level of the PSC be established at 40% of the level of the POD charge. The AESO considered that the structure of the PSC should follow the structure of the POD charge, such that the credit incorporates 40% of each component of the proposed POD charge, as follows:

²⁰² Ex. 064

²⁰³ Decision 2005-096, p. 38

²⁰⁴ Decision 2005-096, p. 40.

Primary Service Credit:
\$1,252.00/MW multiplied by the Substation Fraction for the first 7.5 MW of Billing Capacity, plus
\$310.00/MW for all Billing Capacity over 7.5 MW, plus
\$1,905.00/month multiplied by the Substation Fraction²⁰⁵

The PSC evolution follows that of the POD charge, as it is a portion of the POD costs that are refunded by the PSC. Parties made various proposals for the PSC that they wished to be approved by the Board.

The AESO originally proposed a two tier POD charge (up to 7.5 MW and over 7.5 MW) and proposed a PSC rate of 40%.²⁰⁶

DUC proposed a rate of 55% for the first two tiers (up to 7.5 MW, 7.5 MW to 40 MW) and 100% for the third tier (incremental loads above 40 MW).²⁰⁷ DUC's recommendation for a PSC rate of 55% of the POD charges was based upon the fact that customers supplied their own substations, not just transformation equipment, as shown in Figure 19 of DUC's evidence. DUC also recommended that the PSC for incremental billing capacity over 40 MW be set equal to their recommended POD charge for billing capacities in excess of 40 MW, a 100% PSC rate for billing capacity in excess of 40 MW. DUC supported this recommendation based upon its evidence which showed that the only incremental cost incurred above this level was for transformation equipment.²⁰⁸

In argument, the AESO observed that DUC's methodology relied directly on the new project data in the Application, which the AESO's proposed PSC level did not. As such, the AESO considered DUC's approach to be superior and should be adopted.²⁰⁹ The AESO then proposed a three tier POD charge (up to 7.5 MW, 7.5 MW to 50 MW, over 50 MW) and proposed a PSC rate of 55%.

TCE argued that those customers who had supplied their own substation should receive a 100% PSC.²¹⁰ TCE maintained that the usage patterns of such customers is not the same as regular customers since these customers receive power further upstream than regular customers and the service is different. TCE argued that customers who own their own substation are responsible for all of their own maintenance, including replacement of major equipment such as transformers and breakers. TCE maintained non-substation costs could be directly assigned to a particular customer and their POD charge set to zero.²¹¹

²⁰⁵ Ex. 005, Application, Section 4, p. 51

²⁰⁶ Ex. 005, Application, Section 4, p. 51

²⁰⁷ Ex. 229, DUC Evidence, pp. 34- 36 and Figure 19

²⁰⁸ Ex. 229, DUC Evidence, pp. 14-17

²⁰⁹ AESO Argument, p. 62

²¹⁰ TCE Argument, p. 61-62

²¹¹ See TCE.AESO-059 (Ex. 126) and TCE Argument, pp. 58-61

In reply DUC noted that for the final tier, the AESO was of the view that the PSC should be 55% of the POD charge, whereas DUC was of the view that it should be 100% of the POD charge. DUC noted the AESO summarized its concerns in argument.²¹²

DUC disagreed and argued that the PSC should reflect cost causation. In order that the PSC does so, it is necessary that there be no incremental POD costs above 40 MW (or 50 MW as per the AESO) for customers that own their own substation.²¹³

DUC disagreed with the AESO's suggestion that there may be some radial lines costs that are higher for larger PODs²¹⁴ and that "[i]n the absence of detailed project data to the contrary ...radial line costs likely increase for larger PODs in a manner comparable to the increased costs of transformation." DUC argued that the AESO's own evidence strongly suggests that there is no correlation between POD size and radial transmission line costs.²¹⁵

The AESO disagreed with DUC's proposal for a 100% credit at the third tier (over 40 MW) level. The AESO submitted that DUC's proposal was based on the hypothesis that above a certain size, the only incremental cost attributable to increasing size relates to the size of transformation. The AESO suggested that radial line costs are likely to also contribute to increasing POD costs for larger PODs for two reasons. First, larger PODs more frequently, and sometimes exclusively, interconnect at 240 kV voltage (rather than 138 kV or 69 kV) and these higher voltage lines are more expensive. Second, larger PODs are generally associated with larger projects for which the incremental cost of locating farther from the existing transmission system may be a lesser consideration than for smaller projects. For example, the AESO stated the large developments occurring in the Fort McMurray area require significant line extensions which would generally not be justifiable for a customer with a smaller project. In the absence of detailed project data to the contrary, the AESO submitted that radial line costs likely increase for larger PODs in a manner comparable to the increased costs of transformation. It was therefore appropriate to maintain the 55% credit against the final component of the POD charge, rather than increase the credit to 100% as proposed by DUC.

In section 5.7.7 of this Decision, the Board has directed the AESO to implement a POD charge design which incorporates four tiers, with the fourth tier commencing at 40 MW.

Both the AESO and DUC have agreed that the PSC for the first two tiers (the first three tiers or up to the 40 MW level under the Board approved approach) should be 55%. ASBG/PGA has argued that it should only be 40%, as originally proposed by AESO. The Board disagrees with ASBG/PGA. The Board considers the evidence of DUC, in particular Figure 19 of its evidence, and endorsed by AESO, to be persuasive. As the AESO explained, DUC's methodology relied directly on the new project data in the Application, which the AESO's proposed PSC level did not. As such, the AESO was of the view that the DUC approach is preferable, and should be adopted. This evidence concluded that 55% was the appropriate PSC level for capacities up to the 40 MW level.

²¹² AESO Argument, p. 62, l. 39 – p. 40, l. 2

²¹³ DUC Reply, p. 9

²¹⁴ AESO Argument, p. 36, l. 29-39

²¹⁵ Ex. 126, TCE.AESO-025

The Board does not accept TCE's argument that customers who provide their entire substation should receive a 100% credit. The POD charge is a postage stamp rate component designed to recover, on an average basis, all costs related to PODs. This includes costs not related to substations, such as radial line costs. The Board considers that a 100% PSC for those levels below 40 MW would not recover an appropriate share of non-substation related costs from these customers.

For these reasons the Board approves a PSC rate of 55% for the first three tiers (capacity levels up to 40 MW) of its approved POD charge design.

With respect to the PSC rate for the fourth and final tier (for incremental capacity above 40 MW), the Board agrees with DUC and approves a PSC rate of 100%. In the rate design directed for the POD charge and the investment function, the rate for the fourth tier has been set at a sufficiently low level that generally the investment that will be made and generally the cost recovered is that related to the incremental cost of transformation.²¹⁶ The Board considers that costs related to non-transformation assets will be recovered in the charges related to the first three tiers or through a customer contribution when system access is originally provided to a customer.

In summary, the Board considers that these PSC rates appropriately credit to customers the amount of the POD charge that is related to facilities they have provided while at the same time ensuring they make a contribution to the cost of non-transformation assets provided for customers. The AESO is directed, in its refiling application, to make the necessary adjustments to the PSC rate to reflect the rates approved by the Board in this Decision.

5.10.2 PSC Eligibility

In the Application, the AESO also proposed to change the focus of the PSC eligibility criteria so that instead of focusing on whether the customer owned transformation would have reduced TFO investment, it would focus on whether the TFO owns conventional transformation equipment used in providing service to the customer. The AESO considered that this change would appropriately accommodate the unconventional and "virtual" interconnections. The AESO also considered that its proposed change would simplify the eligibility criteria.²¹⁷

Regarding unconventional interconnections, the AESO stated that some small loads are interconnected to the transmission system through facilities such as metering transformers, rather than load transformers. Such small loads would generally be served through a distribution connection, but at the time of interconnection were probably located more closely to a transmission line than a distribution line. Distance-related considerations likely led to choosing a transmission interconnection, while using metering transformers instead of a conventional substation resulted in substantially lower costs to do so. Given this lower total cost, the unconventional interconnection would connect to the transmission system rather than a distribution network.

Regarding "virtual" interconnections, the AESO considered some small loads to be receiving "virtual" transmission services. Under section 3(b) of the *Isolated Generating Units and*

²¹⁶ See Section 5.7.4, refers to CG.DUC-1(c) and DUC Evidence (Ex. 229), pp. 13-16

²¹⁷ Ex. 005, Application, Section 4, p. 52

Customer Choice Regulation,²¹⁸ transmission charges are attributed to an isolated community “as if the isolated community were being provided with system access service via the interconnected electric system.” However, there is no physical transmission substation associated with the isolated community. If those communities were actually connected to the electric system, their small capacities would likely lead to connection through a distribution network, rather than directly to the transmission system as a stand-alone substation.²¹⁹

DUC disagreed with the AESO that isolated generating units should be eligible for the PSC. DUC noted in its evidence²²⁰ that the tariff from ATCO Electric to the AESO includes the revenue requirement associated with the isolated generation units, including capital recovery, maintenance and fuel costs. In DUC’s experience the provision of electricity from remote generators has a full cost in excess of \$250/MWh.²²¹

DUC also noted that while the tariff from ATCO Electric to the AESO for the isolated generation units excludes costs related to transmission substations (as there are none), the isolated generation unit costs are included. DUC observed that costs per isolated generation site are on average over \$2 million per year,²²² well in excess of the estimated DTS revenue of the \$160,000 per year the AESO receives from each of these sites.²²³

DUC opposed extending the PSC to isolated generation communities. It maintained that dual use customers experience increased costs and cause decreased costs to all other AESO customers by investing in their own facilities. It considered that in the case of the isolated generation units, there is no cost saving choice. The lowest cost option (interconnection to the grid or isolation generation unit) is provided. There is no avoided investment that makes AESO customers better off, and hence there should be no tariff cost reduction (through a PSC to AE) for the isolated generation units. DUC did consider it appropriate to provide the PSC to the two unconventional interconnection sites, since the use of less costly devices such as a potential transformer, instead of a transformer, generally result in a significant capital cost reduction and savings to other AESO customers.²²⁴

CCA/PICA supported the AESO in extending the PSC to isolated community PODs, since those PODs do not own conventional transformation facilities. They argued that an economic choice was made to use isolated generation instead of conventional transformation with interconnection to the grid. This choice was considered to be no different than an industrial customer who makes an economic choice between providing its own transformation or using system supplied transformation. If the industrial customer is eligible for primary service credit so should the isolated community, argued CCA/PICA.

In reply DUC stated that CCA/PICA failed to recognize the significant difference between the choice ATCO Electric made to serve remote communities with diesel fired generation and the

²¹⁸ Alberta Regulation 165/2003, as amended

²¹⁹ Ex. 005, Application, Section 4, p. 52 and p. 20

²²⁰ Ex. 229, DUC Evidence, p. 38

²²¹ Ex. 229, DUC Evidence, p. 38, citing ATCO Electric’s 2007 TFO filing forecast cost of \$247/MWh excluding return on equity and debt costs (p. 4-1 & Schedules 5-1, 5-6 & 6-6)

²²² ATCO Electric’s 2007 TFO Filing shows forecast cost of over \$18 million excluding return on equity and debt costs and Schedule CG.AESO-17 (b), p. 2 of 2, shows a total of eight isolated sites.

²²³ DUC POD PSC Evidence CG 17 Expanded.xls, tab CG-017 (b-c) PSC Details p2, cells M8:R22

²²⁴ Tr. Vol. 6, p. 1367

choice that industrial customer made to own the substation. All of ATCO Electric's costs to provide service to the remote communities are included in either ATCO Electric's tariff or in the AESO's tariff. None of the costs an industrial customer invests in its substation are reflected in the AESO's tariff or any other tariff. Since there is no capital investment reductions, and resulting cost benefit to AESO customers, from the isolated generation PODs, DUC maintained the PSC should not apply to them.

TCE maintained that isolated generation customers are already receiving what appears to be a substantial subsidy from other transmission customers,²²⁵ and that it was therefore inappropriate to provide them with a credit for a transmission facility that they do not require, but for which they have made no expenditure.

In argument, the AESO proposed that that the PSC should apply to all PODs which, for whatever reason, do not make use of transformation.²²⁶ It considered that this would allow the POD charges to appropriately reflect average costs where customers have installed their own transformation facilities, for PODs that are small and/or unconventional, and for isolated communities.

The Board accepts the evidence of DUC that isolated generation unit customers are already receiving a considerable cross-subsidy from other customers. The Board also agrees with TCE that it would be inappropriate for customers already receiving the benefits of isolated generation service to receive additional benefit through the PSC. The Board rejects the argument of CCA/PICA that the isolated generating units should be eligible because the AESO has not invested in standard facilities. The Board considers that the PSC should only be paid when a customer both avoids AESO investment and genuinely reduces costs to other customers. In the case of the isolated generating units, the customers have not provided their own facilities and no real savings to other AESO customers have been demonstrated. Isolated generation is a substitute for transmission service. The savings related to an isolated generation connection are already captured by the fact that the load is being served by isolated generation, thereby alleviating the need to pay for a transmission line to be built and maintained, and further alleviating the risk of stranded costs. The Board therefore finds that the isolated generating units are not to be eligible for the PSC.

The Board does concur with the AESO's proposal to extend the PSC to other unconventional interconnections, as described in section 4.5.2 of the Application. As noted by DUC these interconnections have resulted in reduced costs to other customers.

The AESO is directed in its refiling application to amend the PSC rate schedule to reflect the Board's findings that eligibility for the PSC is to be restricted to dual use customers and those unconventional interconnections described by the AESO in section 4.5.2 of the Application. Isolated generating units will not be eligible.

5.11 Standby Rates

During the AESO's 2005/2006 GTA, the AESO committed to consider the need for a backup or standby service in its next tariff application. It defined standby service as serving a customer load

²²⁵ Ex. 229, p. 38, lines 21 to 25

²²⁶ Ex. 005, p. 52

10 Adjust Primary Service Credit

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Direction

In summary, the Board considers that these PSC rates appropriately credit to customers the amount of the POD charge that is related to facilities they have provided while at the same time ensuring they make a contribution to the cost of non-transformation assets provided for customers. The AESO is directed, in its refiling application, to make the necessary adjustments to the PSC rate to reflect the rates approved by the Board in this Decision. [p. 66]

Response

The Primary Service Credit directed by the EUB as described above is summarized in the following table

Rate Component	DTS Charge	Primary Service Credit	
	Amount	%	Amount
Billing Capacity Charge ≤7.5 MW	\$3,090.00/MW	55%	\$1,700.00/MW
Bill Cap Charge >7.5 to ≤17 MW	\$1,069.00/MW	55%	\$588.00/MW
Bill Cap Charge >17 to ≤40 MW	\$627.00/MW	55%	\$345.00/MW
Billing Capacity Charge >40 MW	\$332.00/MW	100%	\$332.00/MW
Customer Charge	\$5,493.00/month	55%	\$3,021.00/month

The Primary Service Credit amounts determined in the table are reflected in Rate PSC in section 6 of this refiling.

The PSC rate schedule notes, “The Primary Service Credit is provided in conjunction with a reduced maximum Local Investment in accordance with the Terms and Conditions of Service.” The reduced PSC investment is determined using corresponding percentage reductions to the maximum investment function described on page 98 of Decision 2007-106, as follows:

Investment Function Component	DTS Investment	PSC Investment	
	Amount	%	Amount
Fixed	\$51,400/year	45%	\$23,130/year
First 7.5 MW of Contract Capacity	\$28,900/MW/year	45%	\$13,005/MW/year
Next 9.5 MW of Contract Capacity	\$10,000/MW/year	45%	\$4,500/MW/year
Next 23 MW of Contract Capacity	\$5,900/MW/year	45%	\$2,655/MW/year
All Remaining Contract Capacity	\$3,100/MW/year	0%	\$0/MW/year

The reduced maximum Local Investment for services receiving the PSC is provided in Article 9.6(a)(ii) of the Terms and Conditions of Service in section 6 of this refiling.

11 Amend PSC Eligibility to Exclude Isolated Communities

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Direction

The AESO is directed in its refiling application to amend the PSC rate schedule to reflect the Board's findings that eligibility for the PSC is to be restricted to dual use customers and those unconventional interconnections described by the AESO in section 4.5.2 of the Application. Isolated generating units will not be eligible. [p. 68]

Response

The direction states that the Primary Service Credit is to be restricted to “dual use customers and those unconventional interconnection described by the AESO” and not provided to isolated generating units. The direction does not specifically address load-only services where customers provide their own conventional transformation facilities. However, some load-only services include customer-owned transformation, such as at the Express Hardisty and Exshaw substations identified in the AESO's response to Information Request CG.AESO-017 (b).

In the discussion preceding the direction, the EUB comments, “The Board considers that the PSC should only be paid when a customer both avoids AESO investment and genuinely reduces costs to other customers.” Load-only services where customers provide their own conventional transformation facilities would generally satisfy this consideration similar to dual-use customers. It is likely the EUB's terminology simply reflected an imprecise heading on Schedule CG.AESO-017 (b-c) provided in the information response.

The AESO has therefore amended the PSC Rate to restrict eligibility for the PSC to customers who purchase, own, and operate their own transformation facilities and to unconventional interconnections, and to specifically exclude isolated communities. The eligibility provisions in the PSC Rate in section 6 of this refiling are as follows.

- Available to: DTS Customers supplied under suitable long term contract who:
- have purchased, own, and operate their own transformation facilities to step the voltage down from transmission voltage to 25 kV or less, and associated low-voltage facilities; or
 - are served through unconventional interconnections such as those using metering transformers.

The Primary Service Credit is not available for service to an isolated community as defined under the *Isolated Generating Units and Customer Choice Regulation*, A.R. 165/2003, as amended from time to time.