

4 2007 RATE DESIGN

5 The rate design proposed in this 2007 tariff application has been developed throughout an extended period of consultation by the AESO with its stakeholders. Over that period, the AESO's primary goal became a definitive and enduring rate design proposal which would contribute to tariff stability and certainty for customers. Where a specific proposal involves a fundamental change to methodology or rate structure, the AESO has proposed a rationale that is robust and sustainable in future applications, again to provide its customers with as much tariff certainty as possible. Other proposals are more minor or consequential in nature, but are intended to provide clarity, transparency, and consistency in both rate design approach and details.

15 The AESO recognizes that significant changes to rates were also proposed in its 2006 tariff application, in response to requirements of the *Transmission Regulation*, customer concerns, and previous EUB Directions. The approved 2006 rates included further changes as required by directions in EUB Decisions 2005-096, 2005-131, and 2005-132. Some stakeholders consider that the changes approved for 2006, in conjunction with those now proposed for 2007, represent too many or too rapid a sequence of changes in transmission rates.

20 Indeed, when development of this application was initiated in late 2005 the AESO expected its proposals would be limited to relatively minor changes to refine rates as implemented in 2006 and to respond to the remaining directions from the decisions issued on the AESO's 2005-2006 GTA.

25 However, as the AESO conducted stakeholder consultation (described in section 3 of this Application), and as the basis for the 2006 rates was reviewed in detail through studies and investigation — primarily in response to EUB directions — the need for more significant changes to rates became apparent. In particular, stakeholders encouraged the AESO to develop rates which fully resolved remaining concerns with the tariff and which would result in fewer rate changes in future tariff applications. In effect, the AESO was encouraged to file a definitive and enduring rate design rather than limit its proposal to minor changes that would potentially require further changes in future applications.

35 The resulting rate changes proposed in this application, although significant for some customers, may still be appropriately characterized as an evolution of and refinement to the AESO's rates. The fundamental principles underlying the rates remain essentially as in the 2006 rates, and the AESO proposes to continue rate structures similar to those implemented in 2006 for most rates through 2007. The proposed changes primarily respond to EUB directions in the three referenced decisions and to conclusions reached in stakeholder consultation during development of the 2007 tariff, with rate levels adjusted to recover the 2007 revenue requirement detailed in section 2 of this Application.

45 The specific rate changes proposed in this application include:

- re-integration of the bulk system and local system charges in the DTS rate into a single system charge based on billing capacity rather than coincident demand;

- elimination of the usage (\$/MWh) component of the POD charge in the DTS rate, removal of the “relief” applicable to single-end-user loads up to 5 MW, and adjustments to the customer and demand components to reflect a single final POD charge design applicable to all DTS customers;
- 5 • mitigation measures to phase-in the final DTS rate over multiple years at specific PODs if the DTS rate would result in new POD-specific bill increases of more than 300%;
- changes to qualifying criteria for the DOS Term rate and changes to DOS rate levels to reflect current transmission system costs;
- 10 • introduction of non-recallable Export Transmission Service Rate XTS and recallable Export Opportunity Service Rate XOS 1 Month;
- introduction of rates for exports over merchant transmission interconnections; and
- adjustments to the Primary Service Credit structure and levels to better align with the POD charge in the DTS rate.

15 All changes to rates, as well as the overall rate design process, are described in more detail in the following section. Changes with respect to terms and conditions of service are presented in section 6 of this Application. Although presented in separate sections, the AESO has improved alignment between rates and terms and conditions in several areas, including between the DTS point of delivery charge and investment levels, through
20 consistent utilization of the substation fraction, and by accommodating changes to the Primary Service Credit in the customer contribution policy.

25 Schedules 5.1 through 5.12 are provided in conjunction with this rate design section. The format of rate calculations in the schedules follows the format used in the AESO’s 2006 tariff application.

30 The net impacts on rates of the changes detailed in this Application are an overall decrease of 3.2% in the Demand Transmission Service (DTS) rate and an overall decrease of 8.1% in the Supply Transmission Service (STS) rate. However, not all components of the DTS and STS rates are affected equally, and changes by component are summarized in Table 4.0.1.

Table 4.0.1 Change by Rate Component, 2006 to Proposed Tariff

Rate Component	Increase (Decrease)	
	DTS	STS
Interconnection Charge	1.1%	-
Losses Charge	-	(5.9%)
Operating Reserve Charge	(14.0%)	-
Voltage Control Charge	(5.1%)	-
Other System Support Services Charge	1.3%	-
Regulated Generating Unit Connection Costs	-	(6.7%)
Total Tariff	(2.7%)	(6.0%)

Note: The current 2006 Rates became effective January 1, 2006

45 These changes reflect the net impact both of changes to the AESO’s revenue requirement and of growth in billing determinants, from the 2006 forecast on which current rates were based to the 2007 forecast included in this Application.

4.1 Legislative Requirements

The *Transmission Regulation* provides certain specific requirements regarding the recovery of transmission system costs from customers of the AESO, as follows:

Transmission projects providing interconnection capacity with other jurisdictions

15(6) *The ISO must include in the ISO tariff, rates and terms and conditions that include costs for use of the interconnected electric system, appropriate for the class of service provided to persons who use the facilities referred to in this section for import or export of electricity to or from Alberta.*

Adjustment of loss factors

21(1) *In accordance with the rules, loss factors may be adjusted by a calibration factor to ensure that the actual cost of losses is reasonably recovered through charges and credits under the ISO tariff on an annual basis.*

Recovery of transmission losses

22(1) *In accordance with the ISO tariff and the loss factors determined under this Part,*

- (a) *the owner of a generating unit must pay location-based loss charges or receive credits;*
- (b) *importers of electric energy under a firm service arrangement must pay location-based loss charges or receive credits.*

(2) *A person receiving transmission service under an interruptible service arrangement for load, import or export must pay location based loss charges that recover the full cost of losses required to provide this service.*

ISO tariff - transmission system considerations

30 *When considering an application for approval of the ISO tariff under sections 121 and 122 of the Act, the Board must*

- (a) *ensure*
 - (i) *the just and reasonable costs of the transmission system are wholly charged to owners of electric distribution systems, customers who are industrial systems and persons who have made an arrangement under section 101(2) of the Act, and exporters, to the extent required by the ISO tariff, and*
 - (ii) *the amount payable by an owner of an electric distribution system is recoverable in the tariff of the owner of the electric distribution system;*

- 5
- (b) *ensure owners of generating units are charged local interconnection costs to connect their generating unit to the transmission system, and are charged a financial contribution towards transmission system upgrades and for location-based cost of losses;*
 - (c) *consider all just and reasonable costs related to arrangements and agreements described in section 9(5) of the Act.*

10 In accordance with section 30 of the *Transmission Regulation*, the AESO has allocated all costs of the transmission system (except for losses and regulated generating unit (RGU) connection costs) to load customers and exporters. The RGU connection costs continue to be allocated to regulated generators “to place existing generation on the same competitive basis as new generation,” as directed in EUB Decision 2000-1 concerning the ESBI Alberta Ltd. 1999/2000 General Rate Application Phase 1 and Phase 2.

15 In accordance with section 22, the cost of transmission system losses is allocated to generators, import service, and opportunity services. Calibration Factor Rider E also applies to those services as required by section 21(1).

20 The allocation of costs to load and supply customers is summarized in Schedule 5.1, and the related allocation of tariff revenue offsets is summarized in Schedule 5.2 in section 5 of this Application.

25 Finally, in accordance with section 15(6), export and import rates are proposed for users of “merchant” transmission facilities.

4.2 Rate Design Principles

30 In its 2006 tariff application, the AESO identified five rate design principles applicable to a utility (adapted from *Principles of Public Utility Rates* by Bonbright, Danielsens, and Kamerschen, 2nd ed., 1988, pp. 385-389):

- (i) Recovery of the total revenue requirement;
- (ii) Provision of appropriate price signals that reflect all costs and benefits, including in comparison with alternative sources of service;
- 35 (iii) Fairness, objectivity, and equity that avoids undue discrimination and minimizes inter-customer subsidies;
- (iv) Stability and predictability of rates and revenue; and
- (v) Practicality, such that rates are appropriately simple, convenient, understandable, acceptable, and billable.

40 The first principle would be satisfied by any rate design that, on a forecast basis, recovered the applied-for revenue requirement.

45 In Decision 2005-096, the EUB considered that the second and third principles would be satisfied by rates which recover costs in the manner in which they are caused. That is, rates based on cost causation should provide appropriate price signals, should be fair, objective,

and equitable, and should minimize or eliminate inter-customer subsidies. Cost causation therefore becomes the primary consideration when evaluating a rate design proposal.

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

The AESO has accordingly based the rate proposals in this 2007 tariff application on cost causation principles as much as possible, as described in more detail in the following section. In particular, the AESO has relied on a *2006 Transmission Cost Causation Update* (provided as Appendix C) as the basis for functionalization and classification of costs for the proposed rates.

4.3 Transmission Cost Causation

As part of the AESO's 2006 GTA, the AESO filed an *Alberta Transmission System Wires Only Cost Causation Study* (the *Transmission Cost Causation Study*, or "TCCS") prepared for the AESO by PS Technologies Inc. The study concluded that transmission wires costs should be functionalized and classified as provided in Table 4.3.1,

Table 4.3.1 2005 Functionalized and Classified Wires Costs, \$ 000 000

Function	Total	Classification		
		Demand	Usage	Customer
Bulk System	\$144.6	\$117.9	\$ 26.7	\$ -
Local System	60.2	49.7	10.5	-
POD	147.8	63.7	1.0	83.1
Total	\$352.6	\$231.2	\$ 38.3	\$ 83.1

Note: Totals may not add due to rounding

For rate design purposes, the functionalized and classified wires costs are generally converted to percentages of total costs, as provided in Table 4.3.2.

Table 4.3.2 2005 Functionalized and Classified Wires Costs ("Original"), % of Total

Function	Total	Classification		
		Demand	Usage	Customer
Bulk System	41.0%	33.4%	7.6%	-
Local System	17.1%	14.1%	3.0%	-
POD	41.9%	18.1%	0.3%	23.6%
Total	100.0%	65.6%	10.9%	23.6%

Note: Totals may not add due to rounding

In Decision 2005-096, the EUB considered “the TCCS to be an excellent first step” (p. 19) and provided directions for additional refinement of the study. Specifically, the EUB provided the following directions:

5 4C. *Parties also questioned the use of CLMS to moderate the demand charge otherwise called for. With respect to this matter, the Board notes that the TCCS appears to have studied only two of many bulk lines in its analysis. IPCAA has argued that one of the two lines studied, the Edmonton-Calgary line, had significant loading caused by opportunity service at the time of CLMS. Indeed, the Board observes that Mr. Reimer, as referenced above, has acknowledged that CLMS may be expected to be more coincident with system peak. As such, the discount that Mr. Reimer proposes in demand related charges may not be fully justified. The Board expects that, in future studies, the AESO will conduct a more thorough review of all those lines comprising the bulk system. This should give a more accurate indication as to the exact portion of costs that are energy related.*
10
15 *(p. 23)*

20 4D. *However, the Board also considers that a reasonable portion of TFO costs are related to O&M and that a material percentage of these may be energy related. Unfortunately, the impact of this factor does not appear to have been researched in this current study and therefore the Board cannot draw a firm conclusion respecting its impacts on the demand charge. Nonetheless, based upon the percentage that O&M expenses comprise of a TFO’s revenue requirement, the Board considers that such an analysis would support a reasonable classification of costs as energy related. The Board expects the AESO to address these issues in future cost of service studies.*
25 *(p. 23)*
30

In addressing these directions, the AESO engaged in stakeholder consultation to develop terms of reference for an update to the *Transmission Cost Causation Study*, and then contracted PS Technologies to update the study in accordance with the terms of reference. The *2006 Transmission Cost Causation Update* is provided as Appendix C to this
35 Application.

4.3.1 Transmission Cost Functionalization

Most of the activities of the *Transmission Cost Causation Update* focused on the classification of costs to demand-related, usage-related, and customer-related portions.
40 However, three activities specifically addressed functionalization of costs to bulk system, local system, and point of delivery (POD) amounts.

The first was an assessment of alignment between:

- the functionalization of costs to local system and point of delivery (POD) in the cost study, and
- 45

- the differentiation of system-related and customer-related costs in the AESO's terms and conditions of service.

The *Update* recommends that high-voltage facilities in networked substations should be functionalized as local system rather than functionalized as POD as in the original *Study*. The *Update* also notes that sufficient data to complete such functionalization is not available nor expected to be available in the near future, and that the original functionalization as POD is generally consistent with the definition of customer-related facilities in the terms and conditions. In any event, aligning functional definitions in a cost study with facility definitions in a contribution policy may involve trade-offs in accuracy for one or the other purpose.

The *Update* therefore concludes that continuing the local and POD functionalization as in the original *Study* is appropriate, based on the lack of available data, the expected small impact of the refinement, and potential resulting misalignment between functionalization and terms and conditions treatment. The functionalization of local system and point of delivery therefore remains unchanged in the *Update*.

The *Transmission Cost Causation Update* also reviewed the functionalization of contributions in aid of construction (CIAC) in the original *Study*. The *Update* has improved the consistency of functionalization of CIAC amounts from all TFOs, and the impact on cost functionalization has been included in Tables 4.3.3 and 4.3.4 provided later in this section.

Finally, the *Transmission Cost Causation Update* included a review of dual-use substation costs, but concluded the functionalization of such costs could not be determined from analysis of the TFO cost data. The *Update* recognized that in Decision 2005-096 the EUB approved dual-use substation cost sharing based on the substation fraction approach. Substation fractions have therefore been used to apportion the cost of dual-use substations between demand (functionalized as POD) and supply (functionalized as bulk system) in the *Update*.

Tables 4.3.3 and 4.3.4 reflect the impact of the two refinements in the *Transmission Cost Causation Update* relating to contributions in aid of construction and dual-use substations costs.

Table 4.3.3 2006 Functionalized and Classified Wires Costs ("Updated"),
\$ 000 000

Function	Total	Classification		
		Demand	Usage	Customer
Bulk System	\$147.0	\$119.8	\$ 27.2	\$ -
Local System	61.3	50.6	10.7	-
POD	144.3	62.2	1.0	81.1
Total	\$352.6	\$232.6	\$ 38.9	\$ 81.1

Note: Totals may not add due to rounding

Table 4.3.4 2006 Functionalized and Classified Wires Costs (“Updated”),
% of Total

Function	Total	Classification		
		Demand	Usage	Customer
Bulk System	41.7%	34.0%	7.7%	-
Local System	17.4%	14.3%	3.0%	-
POD	40.9%	17.6%	0.3%	23.0%
Total	100.0%	66.0%	11.0%	23.0%

Note: Totals may not add due to rounding

The remaining activities of the *Update* affected the classification rather than functionalization of wires costs, and in particular addressed the two directions cited from Decision 2005-096.

4.3.2 Bulk Transmission System Cost Classification

A significant portion of the analysis completed for the *Transmission Cost Causation Update* involved the “more thorough review of all those lines comprising the bulk system” required by Direction 4C of Decision 2005-096. PS Technologies first interviewed AESO system planners to discuss transmission paths, requirements to upgrade the bulk transmission system in different areas of Alberta, and causes of maximum stress on bulk transmission lines. This qualitative review was followed by a quantitative analysis of the relationship between loading on individual bulk transmission lines (as representative of maximum stress) and total Alberta Internal Load (AIL).

Contrary to the expectation expressed during the AESO’s 2005-2006 GTA hearing, the *Transmission Cost Causation Update* found that there was very weak correlation between individual bulk line loading and total AIL. Based on metered data for the 8,760 hours in 2005, the load over all seventy-nine 240 kV bulk transmission lines in Alberta (weighted by line length) showed only an 8% correlation with AIL. In response to concerns about basing material conclusions on a single year’s data, the analysis was repeated using metered data for the 8,760 hours in 2004, resulting in bulk line load showing a somewhat lower 1% correlation with AIL.

Additional weighted and unweighted analysis incorporating net book value and percentage of thermal line rating provided correlations from -3% to +18% for 2005 data, and from -3% to +11% for 2004 data. Detailed review of the line data also showed that:

- None of the 240 kV lines experienced their monthly peaks during the times of AIL monthly peaks.
- During the hour of annual AIL peak, lines were loaded at about 60% of their annual peak load on average.
- During the hour of annual AIL peak in 2005, only four of the seventy-nine 240 kV lines were loaded at 90% or more of their annual peak. In 2004, only five of the lines were loaded at 90% or more.

Based on this qualitative and quantitative review and analysis, the AESO concludes that recovering bulk system costs on a coincident peak basis cannot be justified from a cost causation perspective. This conclusion was proposed to stakeholders as part of the AESO’s

2007 tariff consultation, and PS Technologies and the AESO responded to stakeholder questions on the analysis and the conclusion reached. Some stakeholders suggested that despite the quantitative analysis, the conclusion was counter-intuitive and therefore unacceptable. In response, the AESO examined bulk line loading patterns in more detail, and provides Figure 4.3.5 as a summary of that examination.

Figure 4.3.5 provides average daily and monthly profiles of loading on each of the seventy-nine 240 kV bulk transmission lines in the AIES, as well as the daily and monthly profile of ALL (the heavy black line) and the average of all 240 kV lines (the heavy grey line). To plot the profile for each bulk transmission line, the average loading on the line was first calculated over all hours in the year, and then the loading in each hour on each line was expressed as a percentage of the average loading for that line. The profile for each line on an hourly and monthly basis was then plotted, and represents variation from the average for the line expressed as a percentage. These profiles reveal a variety of information.

First, the hourly profiles (the top chart) show that the loading on many lines varies in a very narrow band from about 90% to about 110% in every hour of the day, on average.

Second, there are excursions outside that band in almost every hour of the day. For example, lines 917L (Janet to East Calgary) and 936L and 937L (Langdon to East Calgary) have profiles with significantly higher-than-average loading in the late afternoon and lower-than-average loading in the pre-dawn early morning. In contrast, lines 910L and 914L (Edmonton to Red Deer), 916L (Sarcee to East Calgary), and 9L59 (Sheerness to Battle River) have the reverse profile: higher-than-average loading in the pre-dawn early morning and lower-than-average loading in the daytime. Other lines have yet other profiles: line 995L (Brazeau to Benalto) has its highest loading in the pre-noon daytime hours.

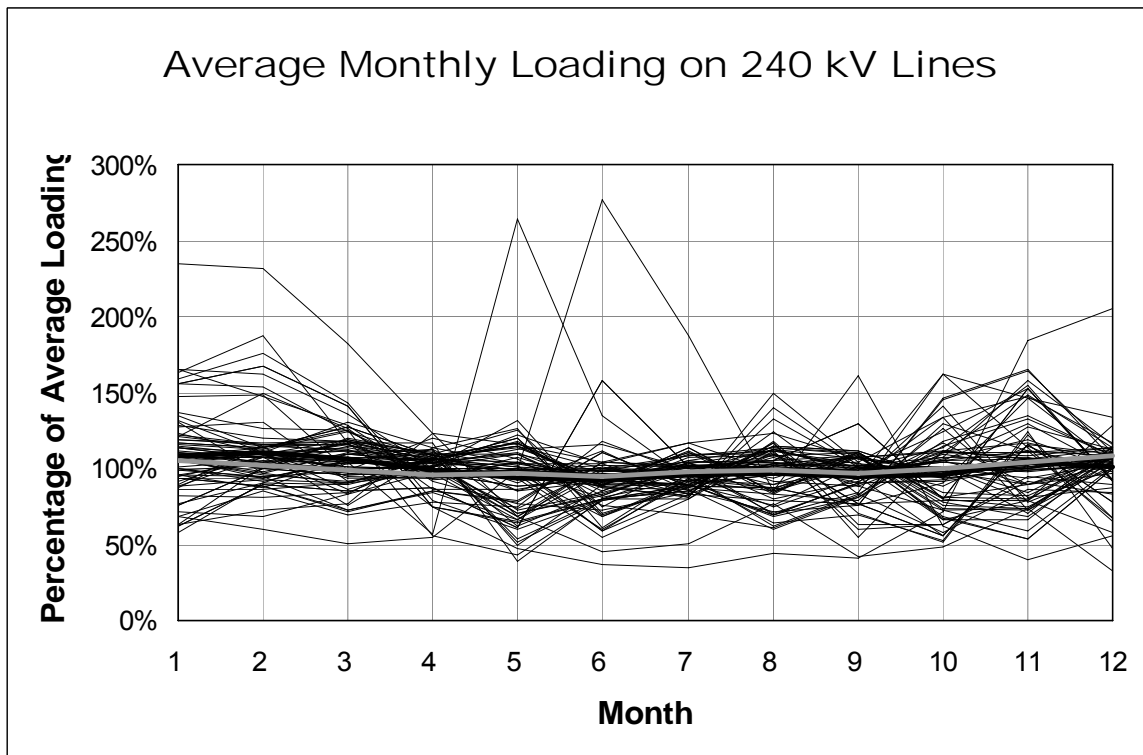
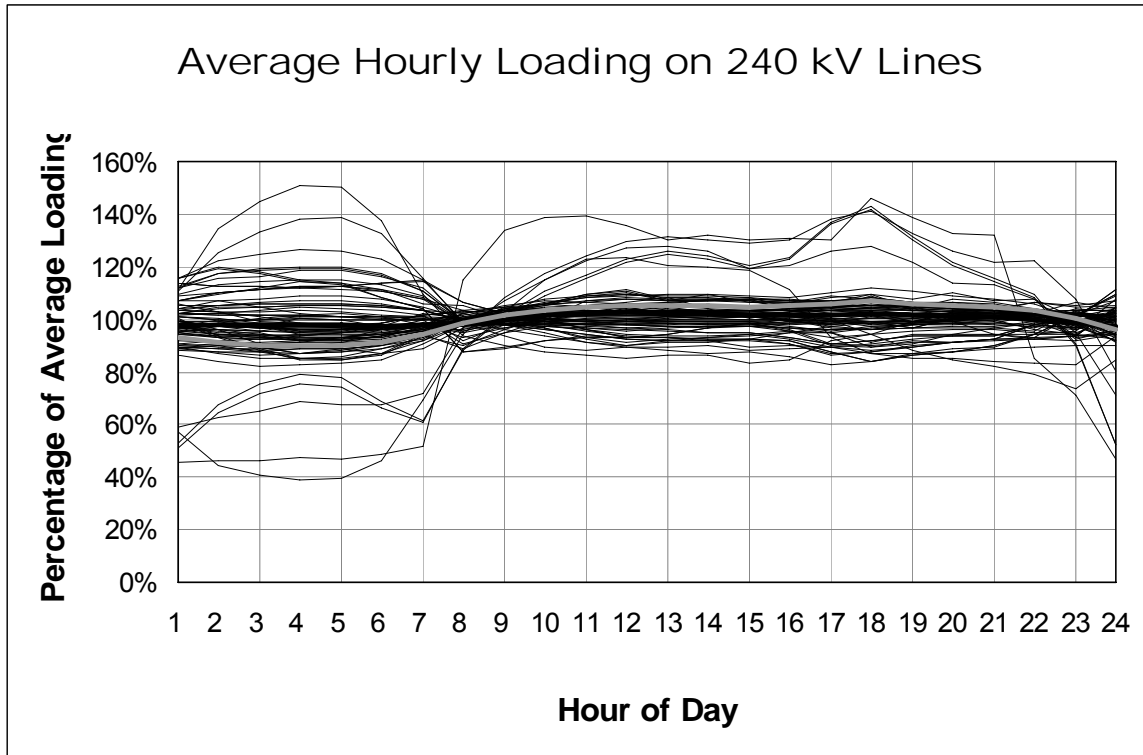
Finally, the monthly profiles are also very flat for many lines, although the variation is wider — from about 75% to about 125% of average loading. Again, there are excursions above and below this range in every month of the year.

Additional analysis of the data is provided in Appendix D of this Application.

The AESO also reviewed the profiles and Appendix D analysis with AESO system planners. All agreed with the conclusions that some bulk transmission line loading varies with total system load, while others do not. Although bulk transmission lines are designed and built to accommodate maximum loading on the line, that maximum loading does not always coincide with maximum system load.

Stakeholders also suggested that the bulk transmission system was designed to accommodate loading under contingency conditions, whereas the analysis in the *Transmission Cost Causation Update* reflects normal operating conditions. Although planning decisions do accommodate contingency conditions, in the AESO's experience cost classification is not based on contingency conditions. Classification of costs is typically based on current usage of the system, and is frequently based on recent historical patterns

Figure 4.3.5 Average Bulk Line and AIL Loading in 2005



(including those established through load research, for example). The AESO is not aware of jurisdictions which classify costs based on system usage under contingency conditions.

5 Some stakeholders suggested that recent usage of the bulk system does not represent either the expectations under which the system was originally planned or future usage after completion of system expansions planned in the next decade (such as the 500 kV North-South Reinforcement, for example). The AESO generally agrees that the nature of the bulk system has changed from the era of centrally-planned generation to the current market-based model, and the location of generation with respect to load has affected usage
10 patterns for the bulk lines. However, some of the lines which do not follow the system load profile date from the time of centrally-planned generation: lines 910L and 914L (Edmonton to Red Deer), 9L59 (Sheerness to Battle River), and 995L (Brazeau to Benalto), for example. Furthermore, the AESO's recent *10-Year Transmission System Plan* and *20-Year Transmission System Outlook* both anticipate additional generation in many areas of
15 Alberta. Current usage of the transmission system under today's market-based model is therefore expected to be representative of future usage. The AESO therefore considers that recent usage of the bulk system is an appropriate basis for cost classification for rate design.

20 Although the AESO supports the *Transmission Cost Causation Update* as an appropriate and sound analysis of transmission system cost functionalization and classification, some stakeholders continued to question the validity of its approach. The AESO therefore retained National Economics Research Associates (NERA) of Los Angeles, California, to conduct a review of the bulk system analysis and conclusions in the *Update*. On the whole, NERA
25 found the proposed functionalization and classification reasonable, although they did offer suggestions for a few refinements to the rate design itself. The AESO posted the NERA assessment report on its website, but did not consult with stakeholders on NERA's findings due to lack of time before filing this application. The AESO also does not rely on the NERA review as part of its evidence and therefore has not filed the NERA report as part of this
30 application.

35 After concluding that recovering bulk system costs on a coincident peak basis cannot be justified from a cost causation perspective, the AESO examined alternatives for recovery of bulk system costs. The AESO also invited stakeholders to suggest an appropriate basis for recovery of bulk system costs. Various recommendations were put forward, ranging from continuing coincident peak recovery for reasons other than costs causation, to expanding the peak demand period to additional coincident hours or a specified time of day, to recovery on an energy basis. The AESO considered these suggestions and concluded at
40 that time that recovery of demand-related bulk system costs on billing capacity is the most appropriate approach.

45 As discussed above, the bulk transmission system, on average, exhibits no distinct hourly or monthly usage patterns. Loading on the bulk transmission system varies from 97% to 103% of average on an hourly basis, and from 93% to 111% of average on a monthly basis. In effect, some bulk lines are heavily loaded, and some are lightly loaded, in every hour of the day and every month of the year. **Load in every hour is therefore important**, since in every hour some bulk lines will be heavily loaded and will need reinforcement if additional

load is to be accommodated. There appears to be no basis to support cost recovery based on loading at different times of day and different months of the year.

5 Some parties suggested costs of the bulk system be recovered based on the coincidence of loads in a region with bulk line loading in the region. The AESO does not consider a regional cost analysis permissible under the *Electric Utilities Act*, which requires the AESO to recover costs on a “postage stamp” basis for all customers.

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

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

25 Highest metered demand, demand ratchet, and contract capacity constitute the billing capacity used for the demand component of the local system and POD charges in the current DTS rate. The AESO proposes that billing capacity also is an appropriate billing determinant for the recovery of bulk system costs. The billing capacity determination is proposed to remain the same as in the current DTS rate; that is, it is the greatest of the
30 highest metered demand in the billing period, 90% of contract capacity, or 90% of the peak demand in the prior 24 months.

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

4.3.3 Operations, Maintenance, and Administration Costs

40 In responding to Direction 4D of Decision 2005-096, PS Technologies reviewed the functionalization and classification of operations, maintenance, and administration (OMA) costs within the *Transmission Cost Causation Study*. The *Update* considered that OMA costs could vary by equipment vintage and type, but noted that data was not available to refine the functionalization and classification of OMA costs. In any event, the *Update* concluded the impact on total cost functionalization and classification would be expected to be small because OMA costs account for about one-quarter of TFO revenue requirements,
45 all equipment involves a similar mix of vintages, and the largest cost function (bulk system) contains relatively equal amounts of line and substation equipment. No changes to the

transmission cost functionalization and classification were recommended as a result of the review of OMA costs.

4.3.4 Transmission Point of Delivery Cost Classification

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

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

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

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

$$\begin{aligned} \text{Point of Delivery Costs} &= \$0.947 \text{ million} && \text{(eq. 1)} \\ &+ (\$0.621 \text{ million/MW} \times \text{first 7.5 MW of DTS Capacity}) \\ &+ (\$0.154 \text{ million/MW} \times \text{DTS Capacity above 7.5 MW}) \end{aligned}$$

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

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

As noted in section 4.2 of this Application, the EUB considered that rates should recover costs in the manner in which they are caused. The recommended cost function provided in equation 1 is reflective of the costs caused by a customer interconnection at a POD. The AESO therefore proposes to classify POD costs based on the cost function provided in equation 1, as detailed in Table 4.3.6.

Table 4.3.6 Classification of Point of Delivery Costs

Cost Component	Customer	≤ 7.5 MW	> 7.5 MW	Total
Unit Cost (\$ 000 000)	\$0.947	\$0.621	\$0.154	
Billing Determinant	4,854.4	32,514.8	82,133.3	
Total Costs (\$ 000 000)	\$4,596.5	\$20,203.8	\$12,665.6	\$37,465.8
Classification	12.3%	53.9%	33.8%	100.0%

The AESO therefore proposes to classify point of delivery costs 12.3% as customer-related and 53.9% + 33.8% = 87.7% as demand-related, compared to the 56.2% customer-related, 43.1% demand-related, and 0.7% usage-related in the original *Transmission Cost Causation Study*. (The AESO notes that the 0.7% usage-related component was re-classified as customer-related in response to Direction 6 in the AESO's 2005-2006 GTA Refiling dated September 27, 2005.)

The AESO recognizes that the classification based on the detailed examination completed to in the *Contribution Policy Study* differs significantly from that based on the zero-intercept analysis presented in the original *Transmission Cost Causation Study*. The proposed classification is based on the more detailed examination of costs completed in the *Contribution Policy Study*. As well, the AESO considers that the proposed classification recognizes that a different cost function is appropriate for smaller interconnection projects, as discussed in more detail in section 4.5 of this Application.

4.3.5 Proposed Transmission Cost Functionalization and Classification

The final functionalized and classified wires costs incorporating the findings discussed above are provided in Table 4.3.7.

Table 4.3.7 Functionalized and Classified Transmission Wires Costs ("2007"), % of Total

Function	Total	Classification		
		Demand	Usage	Customer
Bulk System	41.7%	34.0%	7.7%	-
Local System	17.4%	14.3%	3.0%	-
POD	40.9%	35.9%	-	5.0%
Total	100.0%	84.2%	10.8%	5.0%

Note: Totals may not add due to rounding

The AESO notes that these findings are further modified for rate design purposes as discussed in section 4.5 of this application.

4.4 Ancillary Services Cost Classification

5 The classification of ancillary services costs was reviewed extensively in the AESO's 2006 GTA. No changes are proposed to the cost classification in the 2007 application from that approved for the AESO's 2006 tariff.

10 However, ancillary services costs have been presented in slightly different detail in the AESO's 2007 revenue requirement. Specifically, costs which were previously identified as Generator Remedial Action Scheme (GRAS) costs now have Brazeau Fast Ramp costs separately identified. Both Brazeau Fast Ramp and the remaining GRAS costs continue to be classified as varying usage-related costs.

4.5 Demand Transmission Service Rate Design

15 The AESO's 2006 DTS rate was significantly unbundled compared to the prior DTS rate. In this application the AESO proposes re-bundling two charges and revising others.

4.5.1 DTS Interconnection — System Charge

20 Specifically, the AESO proposes re-bundling the bulk system and local system charges into a single system charge because:

- it is now possible to do so as billing capacity and energy are proposed as the billing determinants for both the bulk system and local system;
- a single system charge aligns with the determination of system-related costs in customer contribution calculations; and
- 25 • a single charge will provide a clearer and simpler price signal to customers.

30 The 2006 DTS rate included three charges for the recovery of transmission wires costs (as well as other industry and general and administrative costs, which are recovered on the same basis as wires costs). The transmission bulk system charge included a coincident demand (\$/MW) component and a usage (\$/MWh) component, and the local system charge included a non-coincident demand (\$/MW) component and a usage (\$/MWh) component.

35 Based on additional investigation conducted as part of the *Transmission Cost Causation Update* and discussed thoroughly in section 4.3.2 of this application, the AESO proposes that bulk system demand-related costs be recovered through a non-coincident demand charge, and more specifically based on billing capacity. Recovery of bulk system costs in this manner results in similar recovery of bulk system and local system costs — namely, on an 81.5% demand- and 18.5% energy-related basis for the bulk system, and on an 82.5% demand- and 17.5% energy-related basis for the local system. Such an outcome is

40 reasonable, considering that both the bulk system and the local system provide service to the same transmission customers, that costs are aggregated over all customers, and that both functions were classified using simple minimum system analyses.

45 However, in its 2006 GTA the AESO moderated the demand classification of the bulk system costs through an analysis of bulk line peak coincidence. This moderation was specifically questioned in Direction 4C of EUB Decision 2005-096. Some stakeholders

questioned the specific approach adopted by the AESO in its 2006 rate design, sometimes even when those stakeholders supported a reduction to the demand-related (and corresponding increase to the energy-related) classification of bulk system costs. Stakeholders also suggested the AESO examine other approaches to cost classification, including the “average and excess method”.

Although the discussion in section 4.3.2 demonstrates that coincidence with system peak is not an appropriate basis for bulk system rate design, the AESO considers that the demand-related classification of the bulk system should be reduced to account for varying POD load factors and varying probabilities that individual POD loads will coincide with maximum stress on transmission system components.

Allocating and recovering the majority of transmission system costs on a non-coincident peak basis may be most appropriate when customers have reasonably similar load factors. This is not the case for the transmission system, where 230 DTS PODs have load factors of 60% or more, 138 PODs have load factors between 40% and 60%, and 117 PODs have load factors below 40%. The “average and excess” method suggested by some stakeholders generally provides better recognition of variations in load factor, since it accounts for the increasing likelihood of an individual customer’s contribution to a peak system component demand with increasing load factor. This method also does not distinguish between customers based on timing of the customer’s load, which seems to appropriately reflect the AESO’s findings in its analysis of the transmission system.

In the average and excess method, the average component is determined by the average system load factor. The AESO considers the appropriate system load factor to use is that of the bulk transmission system lines which were examined as part of the *2006 Transmission Cost Causation Update*. The length-weighted average 240 kV line load factor was 50.0% in 2005 and 47.3% in 2004. The AESO recommends using the average of these two load factors, namely 48.6%, to determine the energy-related classification of transmission system costs.

Although the 240 kV lines were primarily functionalized as bulk system in the *Transmission Cost Causation Study*, the average line load factor is likely representative of both bulk and local systems due to the similarity of the systems as discussed above. The AESO therefore recommends the 48.6% energy-related classification of both bulk system and local system costs.

The excess component represents the amount of system load above the average, and is simply the balance of costs which is recovered on a non-coincident peak basis. From the length-weighted average 240 kV line load factor discussed above, 51.4% of transmission system costs would be classified as demand-related and recovered through demand charges.

The AESO recommends the 48.6% energy-related and 51.4% demand-related classification for recovery of the entirety of transmission system costs. The average and excess method is generally an alternative to the minimum system approach which was utilized in the original

Transmission Cost Causation Study, and the two approaches should not be applied together.

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

The classification proposed for the DTS rate based on a single system charge and application of the average and excess method as discussed above is provided in Table 4.5.1.

Table 4.5.1 Functionalized and Classified Transmission Wires Costs ("Rate Design"), % of Total

Function	Total	Classification		
		Demand	Usage	Customer
System	59.1%	30.4%	28.7%	-
POD	40.9%	35.9%	-	5.0%
Total	100.0%	66.3%	28.7%	5.0%

Note: Totals may not add due to rounding

The system charge resulting from the functionalization and classification of Table 4.3.8 is provided in Schedule 5.5 in section 5 of this application, and amounts to:

DTS System Charge:

- \$1,176.00/MW of Billing Capacity, plus
- \$2.42/MWh of Metered Energy

This charge is included in the DTS rate schedule in section 7 of this application.

4.5.2 DTS Interconnection — Point of Delivery Charge

The AESO proposes to continue to recover point of delivery costs primarily through demand (\$/MW) and customer (\$/month) rate components, based on the revised classification discussed in section 4.3.4 of this application.

The EUB also provided the following specific direction related to POD charges in Decision 2005-132:

5. *The Board expects the AESO to conduct further analysis upon POD costs and to file such with its 2007 GTA. At a minimum the Board expects such analysis to contain:*
 1. *information respecting the items comprising POD costs,*
 2. *the costs of PODs serving smaller loads vs. those serving larger loads,*

3. a discussion of whether a reasonable break point exists between such PODs, and
4. what additional relief, if any, should be offered to customers who may have paid for the cost of their own transformation equipment. (p. 4)

With respect to items comprising POD costs, three distinct components are generally included in facilities functionalized as point of delivery:

- (i) radial line built solely to interconnect the substation;
- (ii) transformation to step down the transmission voltage to lower levels; and
- (iii) buswork, switchgear, communication equipment, and sitework.

As part of the *Customer Contribution Study* discussed in section 6 of this Application, the AESO examined in detail the costs for 30 transmission interconnection projects which represent all “greenfield” load-only interconnections occurring from 1999 to 2005. The available data did not provide a breakdown of costs into the three components listed above, although data for radial lines and for substations (including transformation and most buswork, switchgear, communication equipment, and sitework) was examined.

Radial line costs were found to correlate well to line length, and poorly to DTS capacity. Average costs for radial line, as functions of line length and of DTS capacity, are as follows:

Radial line costs exhibited very strong correlation with line length:

$$\text{Radial Line Costs} = \$0.534 \text{ million} + (\$0.071 \text{ million/km} \times \text{Line Length}) [r^2 = 0.845]$$

Radial line costs exhibited much weaker correlation with DTS capacity:

$$\text{Radial Line Costs} = \$1.646 \text{ million} + (\$0.013 \text{ million/MW} \times \text{DTS Capacity}) [r^2 = 0.002]$$

Average substation costs exhibited a stronger correlation with DTS capacity:

$$\text{Substation Costs} = \$1.848 \text{ million} + (\$0.122 \text{ million/MW} \times \text{DTS Capacity}) [r^2 = 0.314]$$

The observed scatter of total project costs as a function of DTS capacity is not unreasonable when the lack of correlation of radial line costs to DTS capacity and the moderate correlation of substation costs to DTS capacity are considered. Radial line costs will add to the data scatter, but the AESO notes that the moderate correlation of substation cost to DTS capacity indicates inherent scatter in the data even when radial line costs are excluded. The AESO attributes the variability of substation costs to different substation configurations, varying geography and construction conditions, and different levels of complexity for each project.

The above analysis is provided in response to part 1 of Direction 5 from Decision 2005-132.

With respect to differences between substations serving smaller loads and those serving larger ones, the *Customer Contribution Study* also found that no small load services have been interconnected in recent history. Specifically, load services smaller than 7.5 MW have

not been interconnected since 1999 nor are any currently being interconnected. The AESO was therefore unable to quantitatively assess the costs of substations serving small load using the recent project data in the *Customer Contribution Study*.

5 To supplement the greenfield project data representing recent projects, the *Customer Contribution Study* utilized data for small projects from the *Transmission Cost Causation Study* to develop an appropriate cost function for load services smaller than 7.5 MW. Based on a minimum-intercept analysis and linear interpolation, the following cost function for projects up to 7.5 MW was established:

10

$$\begin{aligned} \text{Point of Delivery Costs} &= \$0.947 \text{ million} && (\text{eq. 2}) \\ &+ (\$0.621 \text{ million/MW} \times \text{first 7.5 MW of DTS Capacity}) \end{aligned}$$

15 The reasonableness of this small project cost function was further assessed with a simple linear regression analysis of the data for small projects from the *Transmission Cost Causation Study*, which provided the following average cost function:

20

$$\begin{aligned} \text{Average Small Project Costs} &= \$0.940 \text{ million} && (\text{eq. 3}) \\ &+ (\$0.595 \text{ million/MW} \times \text{DTS Capacity}) \end{aligned}$$

The AESO suggests this average cost function supports the small project cost function recommended as equation 2.

25 As a result of this analysis, the AESO concludes that average costs of substations serving smaller loads are significantly different than average costs of substations serving larger loads. The AESO notes that this analysis was completed for loads interconnected through conventional substation and line facilities.

30 The *Customer Contribution Study* also analyzed point of delivery costs above and below various thresholds for the 30-project data set included in the *Study*. Although there appeared to be no threshold which provided higher regression coefficients both above and below it, there was significant variation between the minimum and maximum costs of substations of comparable size, attributable in part to radial line included in the point of delivery costs. The *Customer Contribution Study* ultimately concluded that the minimum-intercept analysis provided the best approach to determine the minimum fixed costs attributable to an interconnection. The AESO recommends that customer-related costs for interconnection project standard facilities be represented by the cost function provided as equation 1 above:

40

$$\begin{aligned} \text{Point of Delivery Costs} &= \$0.947 \text{ million} && (\text{eq. 1}) \\ &+ (\$0.621 \text{ million/MW} \times \text{first 7.5 MW of DTS Capacity}) \\ &+ (\$0.154 \text{ million/MW} \times \text{DTS Capacity above 7.5 MW}) \end{aligned}$$

45 This cost function provides a reasonable distinction between the costs of PODs serving smaller loads and those serving larger loads, for substations interconnected through conventional transmission substation and line facilities. However, some small services are interconnected through unconventional facilities:

- 5 (a) 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 were probably close to a transmission line and distant from a distribution line at the time of inter-connection. Distance-related considerations likely led to the choice of a transmission interconnection, while the use of metering transformers allowed an interconnection at substantially lower cost than a conventional substation. As a result, the lower total cost of the unconventional interconnection would be the reason that these small loads are connected to the transmission system rather than a distribution network.
- 10
- 15 (b) Some small loads represent “virtual” transmission services for the purpose of section 3(b) of the *Isolated Generating Units and Customer Choice Regulation*, whereby 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. As an example, the previously-isolated community of Fox Lake, about 20 90 km east of Fort Vermilion in northern Alberta, was connected to the electric system in 2005. The distribution feeder providing the connection was supplied from an existing substation in ATCO Electric’s service area, rather than through a transmission substation supplying only the isolated community itself.
- 25

The AESO therefore concludes that the recommended cost function developed in the *Customer Contribution Study* may not appropriately represent small load services having unconventional interconnections as discussed above. Where small loads are served through unconventional interconnections, the AESO proposes they be eligible for the Primary Service Credit, as discussed in more detail in the following section and in section 4.10 of this Application.

30

The above discussion is provided in response to parts 2 and 3 of Direction 5.

35 As discussed above and in the *Customer Contribution Study*, the AESO considers that the use of a minimum-intercept analysis to determine the recommended cost function provides an appropriate basis for the Point of Delivery Charge in the DTS rate design.

40 However, during stakeholder consultation the AESO initially proposed a “grandfathered” rate to address the minimum cost function of small services. That rate was proposed to contain a single demand charge and be available only to load services with DTS contract capacities of 5 MW or less as of January 1, 2006, similar in effect to the provision in the 2006 DTS rate that provides a demand charge in lieu of a fixed charge for loads up to 5 MW (established in Decision 2005-132). The proposed “grandfathered” rate was essentially another approach which reflected below-average costs of small services.

45

Based on concerns raised by stakeholders with respect to the closed nature of the “grandfathered” rate and justification for the 5 MW threshold, the AESO examined in more detail the cost data included in the *Customer Contribution Study* and the premises upon which costs for small loads would be expected to be incurred. That more detailed examination resulted in the recommended cost function developed in the *Customer Contribution Study*, which the AESO considers to provide a sound basis for the POD charge. The customer (\$/month) component of the cost function was also supported by the least cost estimates for several stand-alone DTS services provided as part of the analysis of Customer-Owned Substation Credits in the AESO’s 2005-2006 GTA.

The AESO notes that the customer (\$/month) and first demand (\$/MW up to 7.5 MW) components of the POD charge in the proposed DTS rate are not unreasonable in the context of the amounts proposed for the “grandfathered” rate: \$4,725.00/month and \$3,105.00/MW in the proposed DTS rate, compared to \$0.00/month and \$5,207.00/MW in the “grandfathered” rate as presented on June 29, 2006. The AESO further notes that a minimum charge of \$1,000.00 month is assessed solely for billing procedures in Articles 15.3(c) and 15.5 of the AESO’s approved terms and conditions of service, which supports that a customer charge of \$4,725.00/month for fixed POD-related costs is not unreasonable.

The AESO considers that the recommended cost function addresses concerns about the cost function for small services, mitigates rate impacts that could occur with other rate approaches, and is appropriate for all customers with conventional interconnections. The AESO has therefore not proposed a “grandfathered” transmission service rate in this Application.

Part 4 of Direction 5 from Decision 2005-132 asked to AESO to consider “what additional relief, if any, should be offered to customers who may have paid for the cost of their own transformation equipment.” In general, charges attributable to such customers are appropriately determined through application of the substation fraction and the Primary Service Credit, as discussed in section 4.10 of this Application.

In reviewing the application of the substation fraction, the AESO notes that the recommended cost function on which the POD charge is proposed to be based was developed using data for single-service load-only interconnections. Where a substation serves both load and generation, or multiple loads, the cost function must be adjusted to reflect the “substation fraction” approach established by the EUB during the course of the AESO’s 2005-2006 GTA. All but two transmission substations with multiple services (either load and generation or multiple loads) have more than 7.5 MW of total contract capacity, and therefore give rise to incremental costs in accordance with the second demand component of the recommended cost function: \$0.154 million/MW × DTS Capacity above 7.5 MW.

In effect, the customer and first demand components of the cost function can be considered representative of the fixed cost of multiple-service substations, since almost all are above 7.5 MW in total capacity. Since the fixed cost should be shared between services at a multiple-service substation, those two cost components should be shared based on the substation fraction of each service. Accordingly, the substation fraction should apply to the

customer and first demand rate components to ensure equitable sharing of charges between customers at multiple service substations.

5 In reviewing application of the Primary Service Credit, the AESO recommends the EUB's question be broadened in recognition of the small services with unusual characteristics discussed in points (a) and (b) above, to "what additional relief, if any, should be offered for *customer interconnections where the TFO does not own conventional transformation facilities?*" Such interconnections would include:

- 10
- those with customer-owned transformation (as contemplated in the current Primary Service Credit);
 - those utilizing metering transformers (as discussed in point (a) above);
 - those which are isolated from the transmission system (as discussed in point (b) above); and
 - other unusual interconnections such as those taking service at transmission-level
- 15 voltage without the use of transformation facilities.

The AESO proposes all such services be eligible for the Primary Service Credit. Additional discussion, including changes to the Primary Service Credit schedule and associated changes to the customer contribution policy, is provided in section 4.10 of this Application.

20 Beyond the revised Primary Service Credit eligibility criteria, the AESO does not consider it necessary to provide any additional relief for customer interconnections where the TFO does not own conventional transformation facilities.

25 The above discussion is provided in response to part 4 of Direction 5.

The POD charge resulting from the functionalization and classification of Table 4.3.8 and the above discussion is provided in Schedule 5.5 in section 5 of this application, and amounts to:

30 **DTS POD Charge:**

- \$3,129.00/MW multiplied by the Substation Fraction for the first 7.5 MW of Billing Capacity, plus
- \$776.00/MW for all Billing Capacity over 7.5 MW, plus
- \$4,762.00/month multiplied by the Substation Fraction

35 This charge is included in the DTS rate schedule in section 7 of this application.

4.5.3 Bill Impact Assessment

40 In Decision 2005-132 concerning the Review and Variation of the Customer Related POD Charge in the AESO's DTS rate, dated December 6, 2005, the EUB stated:

45 *In Decision 2005-096, the Board made it clear that it considered cost causation to be the primary criterion that should be used in rate design. The Board continues to hold this view. While the Board considered cost causation to be the primary criterion to be used in rate design, it is not the only criterion*

to be given consideration. The Board also made it clear that some consideration should be given to other criteria, including “rate shock”.

5 *The new evidence received from the AESO in the Refiling and Supplementary Filing revealed that the impact on the monthly bills for low load customers of 5 MW or less, absent an ability to factor in a drop in an STS rate, was substantial and could be in excess of 400%. Accordingly, the Board considered that in view of the new evidence that the AESO had submitted as part of its Supplementary Refiling, the IR responses of October*
10 *28, and the comments of individual customers such as Baymag and OxyVinyls Canada, that some customers may indeed suffer some unreasonable level of rate shock and that relief may be warranted. (p. 2)*

15 The AESO notes that the views of the EUB summarized above are consistent with the rate design principles provided in section 4.2 of this Application. In the context of these views and principles, the AESO assessed the impact of the proposed DTS rate to determine whether relief would be warranted for the AESO’s 2007 tariff.

20 Bill impacts may be assessed over different periods and on different bases. The AESO consulted with stakeholders on an appropriate approach to bill impact assessment, and proposes the following terms for the assessment of bill impacts arising from the 2007 DTS rate:

- 25 (a) Bill impacts should be assessed based on changes from 2005 to 2007 rates rather than from 2006 to 2007 rates. Although bill impacts are traditionally assessed for a change from current rates to proposed rates, the AESO considers that unique aspects of the current situation warrant assessment over two rate changes (from 2005 to 2006 rates and from 2006 to 2007 rates). The circumstances include:
- 30 • the significant restructuring of the DTS rate in the AESO’s 2006 tariff and, to a lesser extent, in the proposed 2007 tariff;
 - the significant increases to some bills arising from the AESO’s 2006 tariff; and
 - the specific relief offered by the EUB to small DTS services being limited to the 2006 test year.
- 35 (b) Bill impacts should be assessed solely on DTS charges and should not include commodity charges. The AESO notes that bill impacts are traditionally assessed on a total bill basis, as stated by the EUB in Decision 2005-096:

40 *In the past when the Board has considered rate shock, the Board has considered the effect an increase will have on a customer’s total bill. The Board continues to believe that this is the most appropriate manner in which to assess rate design proposals. (p. 27)*

45 However, the AESO again considers that unique aspects of the AESO’s tariff make a DTS-only assessment appropriate. Primarily, the price of the energy commodity to AESO customers is not a regulated quantity. DTS customers make individual

arrangements for commodity purchases which are not visible to the AESO and which may not be reflective of pool price. Any comparison which included commodity price would therefore include assumptions that would not be appropriate for some customers. As well, total bill impact assessments typically incorporate regulated default supplier rates to end-use customers. Most transmission services do not supply end-users but rather distribution utilities, and the impact on end-users is not known.

(c) Bill impacts should be assessed on individual DTS PODs rather than on customer aggregations of PODs. The DTS rate reflects cost drivers at individual PODs, and bill impacts should be assessed on a similar basis. Bill impacts are traditionally assessed on either an individual service basis or a rate class basis, and generally do not aggregate multiple services supplying one customer (and undoubtedly not if those services are in different rate classes).

(d) Bill impacts should be addressed through appropriate rate structures to as great an extent as possible. The AESO considers that the proposed DTS rate structure has mitigated rate impact to many individual PODs through the considerations incorporated into the rate design. Where rate impact remains a concern and is of a level which requires relief, the AESO proposes that POD-specific relief be offered.

Based on these considerations, the AESO completed a POD-by-POD comparison of bills under the 2005, 2006, and proposed 2007 DTS rates. Monthly bills were calculated under each rate using actual customer billing determinants from June 2005 through May 2006 (including demand determinants from June 2004 through May 2005 for ratchet calculations). The twelve monthly bills were then averaged for each rate, and increases attributable to the rate changes determined. The average bills for individual PODs are provided in Appendix E, and are grouped by billing capacity and load factor in Table 4.5.2.

Table 4.5.2, and the individual POD bill impacts in Appendix E, must be viewed in the context of an average 68% rate increase due primarily to the allocation of all costs of the transmission system (except for losses and regulated generating unit connection costs) to load customers and exporters in 2006 under the *Transmission Regulation*. The POD groups provided in Table 4.5.2 show average increases from 2005 to 2007 ranging from 46% to 268%.

Three general trends can be observed in the table.

- Smaller PODs receive significantly larger increases than larger PODs, primarily due to the fixed component of the POD charge introduced in the 2006 DTS rate and continued (although at a reduced level) in the proposed 2007 rate.
- PODs with load factors from 10% to 50% receive somewhat larger increases than PODs with higher load factors, generally due to the higher proportion of fixed and demand charges in the 2007 rate compared to the 2005 rate.
- PODs with load factors of less than 10% receive less than the average increase in each capacity range, primarily due to the application of the substation fraction at many of the substations which these services share with generators.

Table 4.5.2 Average Per-POD DTS Bill Impacts by Billing Capacity and Load Factor, 2005-2007

Description	Billing Capacity (MW)						Total
	0 to <5	5 to <10	10 to <17	17 to <25	25 to <50	50 to 180	
0% to <10% Load Factor							
Number of Accounts	29	4	6	6	1	3	49
Monthly Usage (MWh)	28	215	295	291	863	692	166
Billing Capacity (MW)	1.2	7.3	12.6	20.6	30.9	94.8	11.8
Load Factor	3%	4%	3%	2%	4%	1%	3%
2005 Monthly Bill	\$1,570	\$10,927	\$15,006	\$28,152	\$45,993	\$129,595	\$15,979
2007 Monthly Bill	\$3,194	\$21,481	\$22,580	\$41,313	\$77,970	\$189,431	\$24,657
2005-2007 Increases (\$)	\$1,624	\$10,554	\$7,574	\$13,161	\$31,978	\$59,836	\$8,678
2005-2007 Increases (%)	103%	97%	50%	47%	70%	46%	54%
10% to <25% Load Factor							
Number of Accounts	14	10	3	4	-	1	32
Monthly Usage (MWh)	162	970	1,660	2,125	-	32,727	1,818
Billing Capacity (MW)	1.3	6.9	13.2	18.4	-	180.0	11.9
Load Factor	16%	19%	17%	16%	-	25%	17%
2005 Monthly Bill	\$2,412	\$12,812	\$24,627	\$31,270	-	\$378,253	\$23,097
2007 Monthly Bill	\$8,864	\$27,752	\$56,431	\$65,917	-	\$556,235	\$43,463
2005-2007 Increases (\$)	\$6,452	\$14,941	\$31,805	\$34,647	-	\$177,982	\$20,366
2005-2007 Increases (%)	268%	117%	129%	111%	-	47%	88%
25% to <40% Load Factor							
Number of Accounts	13	5	8	4	5	1	36
Monthly Usage (MWh)	590	1,753	3,474	5,357	7,938	26,779	3,670
Billing Capacity (MW)	2.6	6.9	14.1	21.4	36.6	105.9	15.4
Load Factor	31%	35%	34%	34%	29%	35%	32%
2005 Monthly Bill	\$5,916	\$15,777	\$31,391	\$51,102	\$74,123	\$220,879	\$33,412
2007 Monthly Bill	\$17,803	\$41,159	\$62,884	\$88,137	\$124,354	\$336,292	\$62,525
2005-2007 Increases (\$)	\$11,886	\$25,383	\$31,493	\$37,035	\$50,231	\$115,413	\$29,113
2005-2007 Increases (%)	201%	161%	100%	72%	68%	52%	87%
40% to <50% Load Factor							
Number of Accounts	16	11	5	4	5	1	42
Monthly Usage (MWh)	623	2,648	4,720	6,936	12,770	21,614	4,188
Billing Capacity (MW)	1.9	8.1	14.7	20.6	37.6	70.1	12.7
Load Factor	46%	45%	44%	46%	46%	42%	45%
2005 Monthly Bill	\$4,910	\$21,557	\$39,279	\$54,840	\$96,043	\$167,424	\$32,835
2007 Monthly Bill	\$14,716	\$50,188	\$78,300	\$91,325	\$158,388	\$259,539	\$61,805
2005-2007 Increases (\$)	\$9,806	\$28,632	\$39,021	\$36,485	\$62,346	\$92,114	\$28,970
2005-2007 Increases (%)	200%	133%	99%	67%	65%	55%	88%

Description	Billing Capacity (MW)						Total
	0 to <5	5 to <10	10 to <17	17 to <25	25 to <50	50 to 180	
50% to <60% Load Factor							
Number of Accounts	13	17	19	13	20	14	96
Monthly Usage (MWh)	676	2,939	5,321	8,054	14,470	29,329	10,047
Billing Capacity (MW)	1.7	7.3	13.0	19.9	35.6	72.6	24.8
Load Factor	55%	55%	56%	56%	56%	56%	56%
2005 Monthly Bill	\$4,958	\$22,034	\$39,021	\$59,937	\$107,618	\$215,787	\$74,302
2007 Monthly Bill	\$11,966	\$50,285	\$75,956	\$105,583	\$175,454	\$328,383	\$124,298
2005-2007 Increases (\$)	\$7,009	\$28,250	\$36,935	\$45,646	\$67,836	\$112,595	\$49,996
2005-2007 Increases (%)	141%	128%	95%	76%	63%	52%	67%
60% to <70% Load Factor							
Number of Accounts	13	22	24	15	29	16	119
Monthly Usage (MWh)	1,781	3,690	6,041	9,494	16,859	39,361	12,693
Billing Capacity (MW)	3.8	7.7	12.8	20.1	35.6	84.1	26.9
Load Factor	65%	65%	65%	65%	65%	64%	65%
2005 Monthly Bill	\$12,382	\$25,301	\$42,141	\$65,579	\$117,417	\$275,298	\$88,425
2007 Monthly Bill	\$29,221	\$53,306	\$82,073	\$115,346	\$188,535	\$410,434	\$145,269
2005-2007 Increases (\$)	\$16,838	\$28,005	\$39,932	\$49,767	\$71,118	\$135,136	\$56,844
2005-2007 Increases (%)	136%	111%	95%	76%	61%	49%	64%
70% to <80% Load Factor							
Number of Accounts	2	9	23	9	14	5	62
Monthly Usage (MWh)	2,085	4,512	7,367	11,482	17,978	40,739	12,467
Billing Capacity (MW)	3.8	8.3	13.3	21.0	33.5	76.4	23.0
Load Factor	76%	75%	76%	75%	74%	74%	75%
2005 Monthly Bill	\$13,436	\$29,491	\$47,960	\$75,285	\$118,400	\$263,068	\$81,385
2007 Monthly Bill	\$26,123	\$62,587	\$88,562	\$124,294	\$188,618	\$396,347	\$135,379
2005-2007 Increases (\$)	\$12,687	\$33,097	\$40,602	\$49,009	\$70,218	\$133,279	\$53,994
2005-2007 Increases (%)	94%	112%	85%	65%	59%	51%	66%
80% to 100% Load Factor							
Number of Accounts	3	13	12	8	9	4	49
Monthly Usage (MWh)	2,227	4,560	8,291	13,696	20,212	57,137	13,989
Billing Capacity (MW)	3.5	7.4	13.5	21.8	32.4	92.0	22.5
Load Factor	89%	85%	84%	86%	85%	84%	85%
2005 Monthly Bill	\$13,809	\$28,499	\$52,152	\$86,031	\$125,913	\$357,967	\$87,573
2007 Monthly Bill	\$23,340	\$50,373	\$95,774	\$141,521	\$198,930	\$529,502	\$141,117
2005-2007 Increases (\$)	\$9,531	\$21,874	\$43,622	\$55,490	\$73,017	\$171,535	\$53,544
2005-2007 Increases (%)	69%	77%	84%	65%	58%	48%	61%

Description	Billing Capacity (MW)						Total
	0 to <5	5 to <10	10 to <17	17 to <25	25 to <50	50 to 180	
All Load Factors							
Number of Accounts	103	91	100	63	83	45	485
Monthly Usage (MWh)	617	3,071	5,732	8,245	15,859	34,574	8,882
Billing Capacity (MW)	2.0	7.5	13.2	20.5	35.0	83.4	21.0
Load Factor	33%	55%	59%	55%	62%	58%	53%
2005 Monthly Bill	\$5,131	\$22,582	\$40,931	\$61,054	\$111,386	\$251,741	\$64,116
2007 Monthly Bill	\$13,023	\$47,989	\$77,985	\$104,492	\$179,509	\$377,431	\$107,162
2005-2007 Increases (\$)	\$7,892	\$25,407	\$37,053	\$43,437	\$68,123	\$125,690	\$43,045
2005-2007 Increases (%)	154%	113%	91%	71%	61%	50%	67%

Overall, however, the trends are less pronounced than those arising from the 2005 to 2006 rate changes, as discussed during the re-filing proceeding for the AESO's 2006 GTA. This moderation of bill impacts reflects the AESO's efforts to balance many concerns in its DTS rate design while maintaining a cost causation basis.

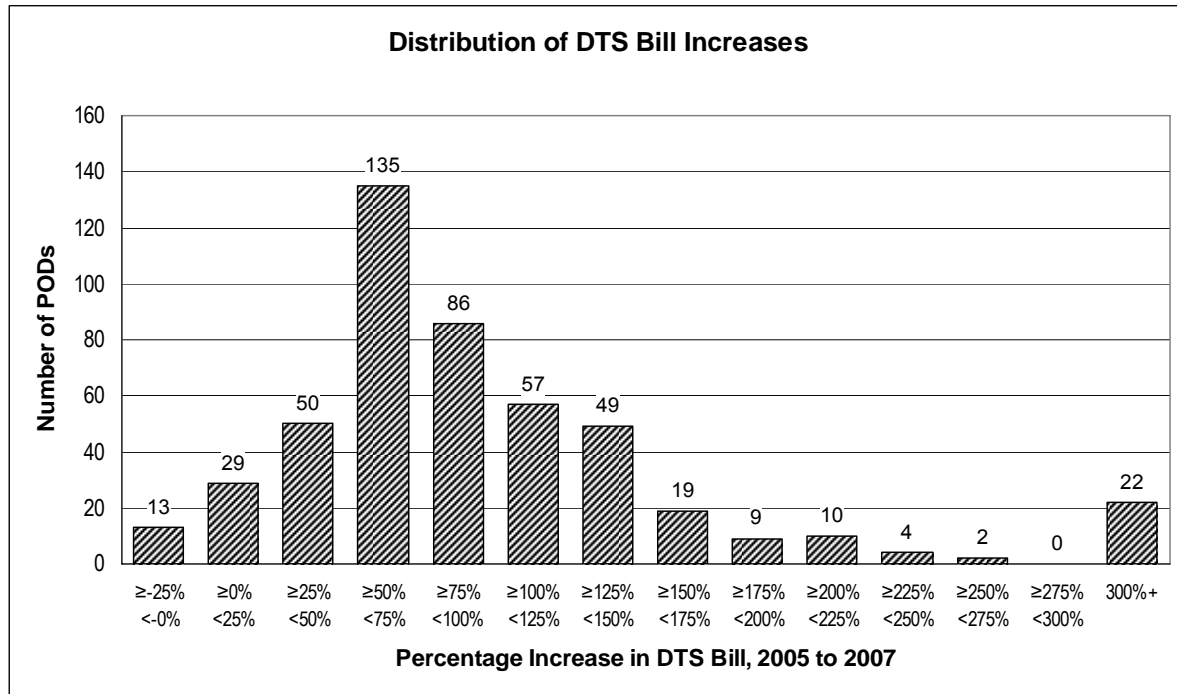
Although Table 4.5.2 provides a useful summary of bill impacts, there is considerable variability in the POD-level detail presented in Appendix E. Individual POD bills are affected by the interaction of many changes in the DTS rate from 2005 to 2007, including:

- introduction of the customer component of the POD charge,
- development of different demand components in the POD charge for billing capacities below and above 7.5 MW,
- reduction of the energy component of the interconnection charge and increases to the customer and demand components,
- application of the substation fraction to the customer and first demand component of the POD charge,
- movement to a 90% 2-year ratchet for billing capacity, and
- recovery of voltage control costs on a fixed rather than varying usage basis.

The interaction of this variety of changes means that impacts on specific DTS PODs can vary significantly from POD to POD. The distribution of bill increases over all DTS PODs is illustrated in Figure 4.5.3.

Individual bill impacts for all 485 DTS PODs are provided in Appendix E. Several individual PODs receive several hundred percent increases in DTS bills from 2005 to 2007. However, the majority of these increases have already been experienced as a result of the impacts arising from the 2006 DTS rate. Also of note is that the PODs receiving the several hundred percent increases are all very small, at 3 MW or less billing capacity. The greatest percentage increases are attributable to the smallest PODs, where DTS bills are increasing from under \$100.00/month to about \$5,000.00/month — a 5,000% increase or more. Although the AESO accepts that a 5,000% increase is large, a \$5,000.00/month bill for transmission service is not unreasonable.

Figure 4.5.3 Distribution of 2005-2007 DTS Bill Increases



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Nevertheless, the AESO agrees that unreasonable bill impacts should be mitigated. As quoted from Decision 2005-132 above, the EUB commented that “impact...in excess of 400%...[could be] considered...unreasonable.” (This comment was in the context of the one-year change from 2005 to 2006 rates.) Stakeholders have also told the AESO that large impacts are unacceptable, primarily because they make it difficult for a business to plan, budget for, and react to changes in transmission costs.

10

The AESO therefore proposes that individual POD increases higher than 300% due to the change from the 2005 to 2007 DTS rate should be mitigated. This mitigation would be achieved through a rider that would cap the increase at those individual PODs to 300% as calculated by the AESO. The effect of this proposal, which relies on the net 2005-2007 impact, is that it protects those PODs that experienced extremely large increases from 2005-2006 from again being subject to sizeable increases less than two years later when the proposed tariff is expected to come into effect. This contributes to rate stability for these PODs.

15

20

Based on Figure 4.5.3, only 22 individual PODs receive increases of 300% or more from 2005 to 2007. However, several of those PODs are actually seeing a **decrease** from 2006 to 2007, as the increase from 2005 to 2006 was larger than the net increase from 2005 to 2007. The AESO proposes that any POD that would see a decrease from 2006 to 2007 rates would not be capped. Those customers have already accommodated the existing

25

increases into their business and presumably additional time to plan and budget for them would have little incremental value now.

Twelve of the 22 PODs mentioned above would see a decrease from 2006 to 2007, and therefore will not have the rates capped. The remaining 10 PODs will have a cap calculated as follows.

Using POD-specific billing determinants from calendar year 2006, the AESO will determine a percentage reduction which, when applied to the interconnection charge in the DTS rate, will result in a 300% increase in the average DTS bill for the POD under 2007 rates compared to 2005 rates. The percentage reductions will be POD-specific and will apply at each rate-capped POD from the effective date of the 2007 tariff to December 31, 2008. The cap will be terminated on December 31, 2008 whether the 2007 tariff continues to be in effect beyond that date or whether a new tariff is effective on January 1, 2009.

The AESO proposes this form of rate cap based on the following considerations.

- (a) The bill increases arise primarily from changes to the interconnection charge level and structure. Other charges included on the DTS bill represent variable costs, which a customer should generally be responsible for and which on their own should not give rise to a 300% increase at any POD. It is therefore appropriate that the cap reduce only the interconnection charge.
- (b) The cap will be implemented as a percentage reduction to the interconnection charge in the DTS rate so that changes in demand and usage at the POD will continue to result in appropriate bill increases and decreases.
- (c) The cap will apply for a specific limited time. The AESO understands that the primary concern with unreasonable bill impacts is that they cannot be readily accommodated in a customer's business. The AESO suggests that terminating the cap at the end of 2008 provides three full years of "notice" for the customer — 2006, 2007, and 2008 — and should provide adequate time for a customer to plan in response to a rate increase.

The AESO proposes that the cap be implemented as Bill Impact Mitigation Rider G, and includes a preliminary rider schedule in section 7 of this Application. When implemented, the rider schedule will list the specific PODs at which the rider applies. However, the specific PODs cannot be listed at this time as a final 2007 DTS rate is not known, the 2006 calendar year data upon which the bill impact will be calculated is not yet available, and the specific impact of the revised Primary Service Credit has not yet been incorporated into the bill calculations. The AESO will prepare a final POD-by-POD bill impact calculation after 2006 billing data is available and when the final DTS tariff is approved, upon which the PODs to which Rider G applies will be determined.

The total relief offered through Rider G is expected to be relatively small — on the order of \$0.25 million. Given this magnitude, the AESO proposes to simply accommodate any revenue shortfall due to Rider G as part of the AESO's deferral account with recovery through the interconnection revenue category of Rider C. The AESO suggests this approach

is practical and avoids concerns with accuracy of forecasts of the amount of relief applicable at specific PODs.

5 The AESO considers the above rate cap proposal to appropriately address any remaining concerns with bill impacts which have not been addressed with the proposed DTS rate design itself.

10 Detailed bill impacts are provided in Appendix E for every DTS POD served through the Alberta transmission system. The data has been provided by distribution utility and for direct-connect PODs, and is sorted in order of increasing billing capacity (MW) and increasing usage (MWh). After sorting, the PODs were assigned sequential numbers from 1 through 485; the AESO will provide a customer with the numbers of their PODs in Appendix E upon request.

15 The AESO notes that the detailed POD bill impacts provided in Appendix E are preliminary. In particular, the 2006 average bills are calculated from only five months of coincident metered demand billing determinants, with the remaining seven months estimated based on those five. As well, changes in contract capacities during the period covered by the billing determinants (June 2005 to May 2006) may result in calculated bill averages that are not
20 representative of on-going bills at a POD. The AESO therefore suggests caution be used when examining the amounts provided, and the average bill amounts should be compared with recent POD bills to verify their reasonableness.

25 **4.5.4 DTS Power Factor Deficiency Charge**

The Other System Support Services Charge in the AESO's existing DTS rate includes a charge for deficient power factor as follows:

30 "...a charge (where Power Factor is less than 90%) of **\$400/MVA** applied to the difference between the highest metered Apparent Power and 111% of the highest Metered Demand during the same Billing Period."

35 This charge has been included in all versions of the DTS rate of the AESO and its predecessors. In the AESO's opinion, the charge appropriately encourages DTS customers to maintain a power factor of at least 90% and discourages excessive reactive power requirements on the transmission system. The charge recognizes that reactive power compensation can generally be applied most effectively at the point of need. The AESO therefore proposes to retain the Power Factor Deficiency Charge in the proposed DTS rate.

40 However, in Decision 2005-025 dated April 6, 2005 on ATCO Electric's 2004 Phase II Distribution Tariff, the EUB provided the following direction:

45 36. *Given that AE indicated that it was willing to work with the AESO to have the power factor waived at PODs that serve D32 (Standby DAT) customers, the Board considers that it would be appropriate to direct AE to work with the AESO. IPPSA argued that its second recommendation be adopted with the caveat that the issue be*

revisited if AE was not successful in eliminating the charges from the AESO, or the charges become too onerous. The Board considers that it would not be appropriate to direct AE to modify price schedule D32 (Standby DAT) without AE first having had sufficient opportunity to work with the AESO, even though the charges may be relatively small. Therefore the Board directs AE, to work with IPPSA and the AESO to resolve the issue of power factor charges to D32 customers and present a solution in its refiling. Should AE be unable to meet this deadline, the Board directs AE, in its refiling, to report as to the difficulties that prevent this change. (p. 45)

ATCO Electric accordingly contacted the AESO, and the AESO and ATCO Electric are working together to address the issue of power factor at Points of Delivery (PODs) with downstream distribution-connected generation. The AESO is completing detailed analysis of PODs with downstream generation, and if appropriate will recommend modifications to the power factor deficiency charge at such PODs in an amendment to this Application. Such an amendment, if required, will be filed as soon as possible after the analysis is completed.

In addition, the AESO proposes revised wording for the power factor deficiency charge to more clearly indicate the basis for the calculation of the charge as currently implemented. The proposed DTS rate schedule includes the following revised description of the other system support services charge:

The **Other System Support Services Charge** equals:

- **\$79.00/MW/month** of highest Metered Demand in the Billing Period, plus
- **\$400.00/MVA** of Apparent Power Difference when Power Factor is less than 90% during the interval of highest Metered Demand in the Billing Period,

where “Apparent Power Difference” is calculated during the interval of highest Metered Demand in the Billing Period as the difference between the metered Apparent Power and 111% of the Metered Demand.

Other than the above changes to interconnection charge and power factor deficiency charge, the remaining components of the DTS rate will continue as in the 2006 tariff, except for adjustments to rate levels to appropriately recover 2007 revenue requirement amounts.

4.6 Backup or Standby Service

Prior to the preparation of its 2005-2006 tariff application, the AESO was approached by customers about provision of a backup or standby transmission service which would supply a customer load that would otherwise be fully supplied by onsite generation during unscheduled outages of the onsite generation. The requirement for such a service was raised during the AESO’s 2005-2006 GTA proceeding itself (summarized on page 30 of EUB Decision 2005-096), and the AESO committed to examining the requirement for a backup or standby service in its next tariff application.

5 Backup or standby service would be available to customers with onsite non-emergency generation, sometimes referred to as “partial-requirements customers”. Partial-requirements services are generally distinguished by low load factors (comparatively low energy usage for a given demand) resulting from usage over periods of short duration or for a few times per year. In contrast, “normal” services have high load factors (comparatively high energy usage for a given demand) and are appropriately served under the DTS rate.

10 Services for partial-requirements customers may be categorized into four types (adapted from *Rate Structures for Customers With Onsite Generation: Practice and Innovation*, National Renewable Energy Laboratory, December 2005, p. 6):

15 (a) *Backup or standby service* serves a customer load that would otherwise be fully served by onsite generation during unscheduled outages of the onsite generation.

(b) *Supplemental service* is for customers whose onsite generation does not meet all of their needs.

20 (c) *Scheduled maintenance service* is taken when a customer’s onsite generation is planned to be out of service for maintenance or repair.

(d) *Economic replacement service* is offered at times when the cost of producing and delivering electricity are less than that of the onsite generation.

25 In the context of these categories of services for partial requirements customers:

- Supplemental service (b) is available under the “full requirements” DTS rate, since it represents an ongoing and recurring service requirement.
- 30 • Scheduled maintenance service (c) is generally available under the DOS (Demand Opportunity Service) Term rate, if the customer would reduce load rather than incur the increased ratchet levels that would apply under the DTS rate (as stated in the AESO’s *Demand Opportunity Service Business Practices*).
- 35 • Economic replacement service (d) is generally available under any DOS rate.

40 The AESO notes that DOS Term is only available for scheduled maintenance *if the customer would reduce load rather than incur DTS ratchet charges*. There may be instances where a customer would not reduce load during scheduled maintenance or repair, and therefore would not currently be eligible for DOS Term. This consideration is discussed further later in this section.

4.6.1 Backup Service Considerations

45 The “partial-requirements” category which is not accommodated under existing rates is backup or standby service (a). The distinguishing features of such a service is that it is usually required for periods of short duration no more than a few times per year and cannot

be predicted or scheduled with certainty, as the backup service is generally required to allow a load process to continue uninterrupted when on-site generation suffers an unexpected outage.

5 Although there is no special provision for backup service in the current AESO tariff, such use of the transmission system is not prevented in any manner (except by capacity or other system constraints). However, stakeholders have questioned whether the charges incurred reasonably reflect the costs caused by such use of the transmission system, when backup service is taken under the DTS rate.

10 Stakeholders generally agree that the charges of concern are the demand components of the bulk system and local system charges under the current DTS rate. Those components include a 2-year 90% ratchet provision which results in long-term impacts when backup service is used for short periods.

15 The AESO understands that the other components of the current DTS rate are not of concern to stakeholders from a backup service perspective. As the POD charge relates to point of delivery costs which are attributable to an individual customer, that customer is fully responsible for such costs either through initial contribution or through the DTS rate over time, and it is not expected that the requirement for backup as opposed to normal service should affect the POD charge. Other components of the DTS rate are also not of concern, as they are billed on metered energy or the highest metered demand in the billing period, and are only incurred in periods when the service is actually taken.

25 The AESO further understands that under the provisions of the current DTS rate, customers who require backup service generally respond to the DTS rate structure in two ways:

- They contract for the capacity needed during the backup load conditions, and thereby minimize the probability of capacity or other system constraints; or
- They contract for the capacity needed during normal load conditions, incur ratchets based on the capacity needed during the backup load conditions, and incur higher probability that constraints may exist at those times.

30

35 In either case, customers who require backup service incur charges higher than those which would be incurred if their load never exceeded "normal" levels. The AESO therefore examined such charges in the context of the costs caused by use of the transmission system for backup service.

40 Initial consideration suggested minimal costs are caused by short-duration, infrequent use of the transmission system. The AESO speculated that loads which occur for less than 10% of the time and for only a few times a year would not affect either long-term or short-term planning decisions, assuming a small number of such loads in any specific planning area, and reasonable non-coincidence of such loads in an area.

45 The AESO accordingly proposed during stakeholder consultation a backup service rate which converted the ratchet charges incurred by loads above contract capacity into a usage (\$/MWh) charge which generated equivalent revenue at a 10% load factor. For load factors

below 10%, lower charges would be incurred on the backup service rate than on Rate DTS, and for load factors above 10%, higher charges would be incurred on the backup service rate. This rate structure was expected to provide a price signal that would prevent inappropriate use of the rate.

5

Stakeholders who provided comments on the proposed backup service rate generally supported it. At the same time, the AESO continued to review the details of the rate within the AESO and developed significant concerns about the unscheduled nature of the service. Specifically, the AESO was concerned that with only a usage charge:

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(a) customers would have minimal incentive to manage backup service requirements such that usage of the service could increase significantly, and

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(b) significantly increased usage could create unforecast and unscheduled loading on the transmission system with considerable risks of voltage deviations or tripping of system elements which would affect all customers in an area and which might result in cascading effects in other areas.

20

Although (as already noted) the current DTS rate allows unscheduled usage, the ratchet provisions of the rate generally encourage customers to minimize backup service requirements. Drastically reducing the charges attributable to backup service use would be expected to encourage unscheduled loading and result in increased risks for system operations and reliability. The AESO estimated that 1,500 to 2,000 MW of load could potentially request backup service and incur minimal cost for utilizing it. Some of these customers would likely be concentrated in areas where concurrent use would intensify operations and reliability concerns.

25

The AESO therefore withdrew its initial backup service proposal and conducted further consultation and investigation into the provision of a backup service.

30

Stakeholders suggested the AESO's concerns with increased or concentrated utilization of backup service could be addressed through conditions or eligibility restrictions on the service, either for a temporary period while the impact of the service is assessed or on a permanent basis.

35

The AESO suggests such conditions or restrictions on eligibility could be considered preferential or arbitrary. For example, backup service is characterized by short duration, infrequent, and unscheduled usage, and those characteristics could also be exhibited by a low load factor load service which intermittently runs above contracted capacity (for example, periodic operation of equipment in a large-machinery testing facility). From a transmission system perspective, there is no cost or operational basis for distinguishing between backup service to a generator and intermittent operation of a load service.

40

Stakeholders also suggested that concerns with concurrent use of backup service or concentrated use in a geographic area could be addressed through operating procedures or technical solutions. The AESO is currently developing transmission constraints management rules which may curtail services to contracted capacities in areas already impacted by

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concurrent use above contract. The draft operating procedure is relatively complex and has received some stakeholder opposition. The AESO suggests that reducing the charges attributable to backup service will worsen the constraints issue and increase the reliance on complex management protocols.

5 The AESO also reviewed a “physical assurance” option recommended in California (*Interim Decision Adopting Standby Rate Design Policies*, California Public Utilities Commission, July 12, 2001, pp. 57-60), where if control devices are installed which disconnect load in the event of a generator outage the customer can receive a lower rate. If such a device is
10 installed by a transmission customer in Alberta, the ratchet provision of the AESO’s current DTS rate would be avoided and the customer would accordingly see no additional charges attributable to backup service.

15 The California PUC concludes, “If a customer is not willing to offer such physical assurance, the utility must construct infrastructure or continue to operate existing facilities to ensure that load from a customer taking on-demand backup service can be served. Therefore, it is appropriate for those costs to be recovered from backup customers.” The AESO generally concurs, but suggests no special option is required if the DTS rate structure appropriately charges for backup service.

20 The AESO therefore further studied the matter of attributing transmission system costs to backup service.

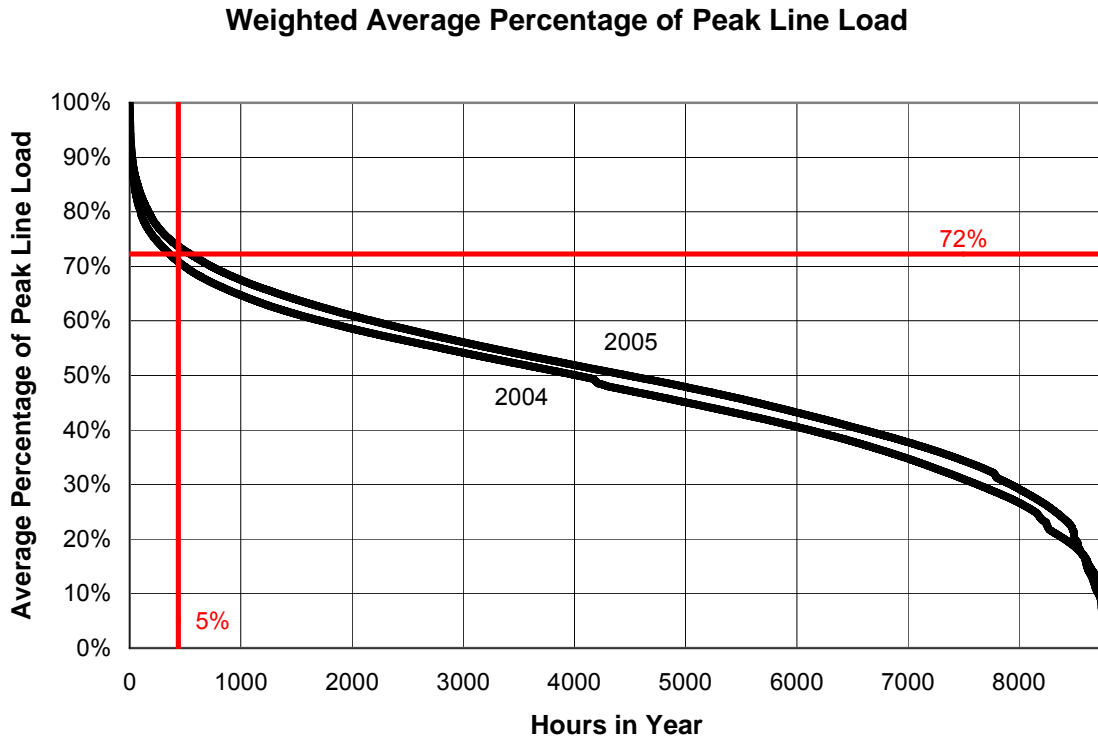
4.6.2 Backup Service Costs

25 Although the transmission system is planned, built, and operated primarily to accommodate normal services, load customers can (and do) utilize the system for backup purposes. This practice has always existed on the transmission system, but has typically not been quantified. The AESO has attempted to assess the costs attributable to backup loads, at least on a comparative basis to normal loads, through two approaches: using historical
30 diversity and using the Northeast Development regional analysis recently completed by the AESO.

35 From a historical diversity perspective, the transmission system is developed to meet demand and energy requirements forecast by the AESO. The forecast incorporates actual hourly load data for each metering point on the transmission system, for the two most recent years for which data is available. (The demand and energy requirements forecast methodology is described in Appendix B of this application.) As the forecast is based on actual metered load data, it includes the effect of actual utilization of the transmission
40 system for backup loads on an historical basis. Actual metered load data includes both normal and backup loads, and embeds historical levels of load diversity (or, alternatively, load coincidence) in transmission development plans.

45 This diversity is apparent in the aggregate load-duration profile of the 240 kV transmission lines analyzed for the *2006 Transmission Cost Causation Update*. The weighted average duration curve for loading on the 240 kV lines for 2004 and 2005, as a percentage of the annual peak load on the lines, is provided in Figure 4.6.1.

Figure 4.6.1 Weighted Average Load Duration Curves for 240 kV Lines in 2004 and 2005, %



The vertical line highlights the 5% (438 hour) duration threshold. The horizontal line highlights the average percentage of peak load at the 5% duration threshold, namely 72%. A 5% duration threshold was chosen as a reasonable representation of backup loads based on three considerations:

- It approximates the point where the load duration curve becomes more vertical than horizontal (that is, where the tangent to the curve becomes greater than 45° from the horizontal).
- The transmission system is generally planned on a 95% probability of load coincidence.
- A similar level has been used in backup rate determinations in some other jurisdictions (Arizona, for example).

Assuming that line loading below the 5% duration threshold represents normal loads, about 72% of peak line loading, and about 72% of transmission system costs, can be attributed to normal loads. Similarly, assuming that line load above the 5% duration threshold represents backup loads, about 28% of peak line loading, and about 28% of transmission system costs, can be attributed to backup loads. Compared to the costs attributed to normal loads, backup loads should be attributed $28\% \div 72\% = 39\%$ of normal costs.

As well, the interconnected capacity of backup loads exceeds the concurrent usage of the transmission system as reflected in system metered data. Based on a review of billing data

from June 2005 through May 2006 for low load factor customers, load capacities of less than 5% duration were about 103% of the DTS contract capacities for those customers. Transmission system costs attributed to backup loads should therefore be assessed against an amount of backup load approximately equal to normal load.

5

This analysis suggests a megawatt of backup load should be allocated $39\% \div 103\% = 38\%$ of the amount that would be charged to a megawatt of normal load.

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A similar but more specific analysis of forecast diversity can be developed from recent northeast Alberta transmission development planning discussions, and provides an indication of the accommodation of backup capacity in transmission plans. Detailed regional analysis such as this is not readily available for other areas of the province.

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The Northeast Alberta Transmission Development stakeholder presentation on October 2, 2006 indicated the region's transmission system was being developed to support 815 MW of normal operating load and 425 MW of backup load. In this case the transmission system is being planned to carry an additional $425 \text{ MW} \div 815 \text{ MW} = 52\%$ capacity above normal operating load which is attributed to backup load. The Northeast Alberta Service Requirements also forecast a total 1,100 MW of backup load to be interconnected. In this case, backup load will be about $1,100 \text{ MW} \div 815 \text{ MW} = 135\%$ of normal load.

20

The Northeast Alberta analysis suggests a megawatt of backup load should be allocated $52\% \div 135\% = 39\%$ of the amount that would be charged to a megawatt of normal load.

25

The Northeast Alberta analysis is consistent with the historical diversity analysis. However, the Northeast Alberta Transmission Development may be somewhat unique in its backup load characteristics, and the AESO suggests the historical diversity analysis should generally be relied on for allocating costs to backup service. The AESO therefore suggests that, based on the historical diversity analysis, a megawatt of backup load should be allocated about 38% of the transmission system charges for a megawatt of normal load.

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4.6.3 Backup Service Rates

The AESO also reviewed the principles on which to base a rate to recover backup service costs.

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On a very basic level, transmission assets represent by nature a long-term fixed investment. Once planned and built, the cost of the transmission system varies very little based on usage. Its cost should therefore be recovered as a fixed, rather than variable, cost, which would generally lead to classification as a demand-related cost. This conclusion applies equally to both that portion of the transmission system planned for normal load and that portion planned for backup load, since the transmission system remains by nature a fixed asset in both cases. Recovery of the demand-related costs of a transmission system over time traditionally leads to incorporation of ratchet provisions. The nature of backup service does not inherently provide any reason to deviate from this approach.

45

As already discussed, the transmission system is built to accommodate the existence of backup loads on a forecast basis. Costs are incurred to provide backup service whether or

not backup usage actually occurs in any specific period. Backup capacity should therefore be paid for on a basis extending beyond the actual usage period, which can also be accomplished by paying for capacity through ratchet provisions.

5 A ratchet-based capacity charge is also an equitable approach to recovering the cost of backup service. Assuming occasional use of the backup capacity, the customer will pay for the service throughout the extended ratchet period. If usage of the backup service becomes so infrequent that it does not recur during the ratchet period, the customer no longer pays in accordance with the reduced likelihood of future use of the service.

10 Although ratchet provisions should apply to capacity utilized for backup service, the capacity charge for such service should be substantially less than the capacity charge applicable to normal service. As discussed earlier in this section, the charges should reflect that the system incorporates a level of diversity and non-coincidence of backup loads, such that a megawatt of backup load should be allocated about 38% of the transmission system charges for a megawatt of normal load. The AESO considers that the system wires charges under the DTS rate proposed in this application appropriately charges for backup service compared to normal service.

15 Normal load at the AESO is about 80% load factor (average AIS loading) and incurs a two-year 90% ratchet. Over a year, a 1 MW normal load would incur the following system wires charges under the proposed DTS rate:

$$\begin{aligned}
 &1 \text{ MW} \times 12 \text{ months} \times \$1,176.00/\text{MW}/\text{month} = \$14,112.00 \\
 &1 \text{ MW} \times 80\% \text{ load factor} \times 8,760 \text{ hours} \times \$2.42/\text{MWh} = \$16,959.36 \\
 &\text{Total annual charge} = \$31,071.36
 \end{aligned}$$

A 1 MW backup load which operated for 5% of the time during the year would incur the following system wires charges:

$$\begin{aligned}
 &1 \text{ MW} \times 1 \text{ months} \times \$1,176.00/\text{MW}/\text{month} = \$1,176.00 \\
 &1 \text{ MW} \times 90\% \text{ ratchet} \times 11 \text{ months} \times \$1,176.00/\text{MW}/\text{month} = \$11,642.40 \\
 &1 \text{ MW} \times 5\% \text{ load factor} \times 8,760 \text{ hours} \times \$2.42/\text{MWh} = \$1,059.96 \\
 &\text{Total annual charge} = \$13,878.36
 \end{aligned}$$

35 The annual charge for 1 MW of backup load would be about 45% of the annual charge for 1 MW of normal load. Although this is somewhat higher than the 38% of charges for normal load discussed above, the AESO considers this amount to represent an appropriate premium for backup service. Addressing specific concerns arising from backup loads incurs greater administration (through technical studies and ongoing assessments) and greater risk (due to the unscheduled and infrequent nature of backup service) than normal service. The northeast Alberta transmission development process is an example of the extensive work completed to ensure backup loads can be accommodated on the transmission system.

45 The AESO therefore concludes the proposed DTS rate accommodates the cost and rate design considerations related to the provision of backup service. The contract capacity and ratchet structure of the proposed DTS rate is a reasonable approach which balances

facilities costs attributed to backup service and risk mitigation. Based on this conclusion, a separate backup rate is not proposed.

4.6.4 Modifications to DOS Term Rate

5 The AESO also examined the need for scheduled generator maintenance service beyond that which is currently accommodated under DOS Term. Currently such scheduled maintenance is eligible for DOS Term only if the customer would reduce load rather than incur the increased ratchet levels that would apply under the DTS rate (as stated in the AESO's *Demand Opportunity Service Business Practices*). The AESO proposes
10 modifications to DOS Term in this application to accommodate scheduled generator outages which should address this customer need. Additional information on the revised DOS rates is included in the following section 4.7 of this application.

4.7 Demand Opportunity Services

15 The tariffs of the AESO and its predecessors have included opportunity service rates for load customers since the electric industry was deregulated in Alberta in 1996. The AESO's current tariff provides three Demand Opportunity Service (DOS) rates: DOS 7 Minutes, DOS 1 Hour, and DOS Term. Opportunity service was defined in EUB Decision 2000-1 on the
20 1999-2000 General Tariff Application of ESBI Alberta Ltd. (EAL):

*EAL offered, in evidence, that opportunity service was a short-term temporary service, provided on an as-available basis, to customers who could clearly demonstrate that their use of the transmission system would not be
25 economically viable at the rates otherwise applicable. EAL further noted that opportunity service was utilized by pre-qualified customers, generally for service of short periods, in order to avoid the impact of contract demand or ratchet charges that would otherwise result.*

*The Board acknowledges that there are situations when the market price of alternative energy for some of the TA's customers could be a viable alternative to electricity. The Board therefore accepts EAL's stated position that the objective of opportunity service is to reduce the level of average rates charged to other customers by applying the extra revenue earned from the
30 use of temporarily under-utilized transmission system assets. The Board further accepts that this requires pricing opportunity service on a value-of-service rather than a cost basis, and the application of criteria to prevent cannibalization of other revenues. At the same time, the Board does not wish to see the use of screening criteria that would prohibit the beneficial use of
35 opportunity service. (pp. 225-226)*

45 The premise of opportunity service is that it should be priced above cost, where cost includes only variable components and not fixed components which would be incurred whether or not the opportunity service was utilized. The AESO therefore examined the variable cost basis for opportunity service rates, as well as other aspects which differentiate DOS 7 Minutes, DOS 1 Hour, and DOS Term rates.

To determine the variable cost for DOS, the AESO first converted all components of its 2007 DTS revenue requirement into \$/MWh amounts as if all were to be recovered on a flat usage (\$/MWh) basis from all DTS customers, as provided in Table 4.7.1.

5 *Table 4.7.1 Conversion of 2007 DTS Revenue Requirement in \$ 000 000 into \$/MWh Amounts*

DTS Rate Component	2007 Revenue Requirement			\$/MWh Based on 54,682.5 GWh		
	Fixed	Variable	Total	Fixed	Variable	Total
Interconnection – System	139.9	132.6	272.5	2.56	2.42	4.98
Interconnection – POD	188.6	-	188.6	3.45	-	3.45
10 Operating Reserve	-	125.2	125.2	-	2.29	2.29
Voltage Control	-	50.8	50.8	-	0.93	0.93
Other System Support	7.8	-	7.8	0.14	-	0.14
Total	336.3	308.5	644.9	6.15	5.64	11.79

15 The fixed and variable component of each DTS rate component was then examined to determine if such costs were incurred in providing service to DOS customers. The AESO proposes the following principles should apply to DOS.

- 20 (a) DOS customers should pay the variable costs associated with the interconnection system component of the DTS rate, as such variable costs are incurred on behalf of all users of the transmission system.
- 25 (b) DOS customers should pay a portion of the fixed costs associated with the interconnection system component of the DTS rate, as a contribution to fixed costs to reduce the level of average rates charged to other customers. As noted by the EUB in Decision 2000-1, such contribution should generally be determined on a “value-of-service” basis. However, the AESO notes that other costs included in the DOS rate represent a significant increase from current DOS levels. The AESO therefore suggests that the contribution to fixed costs be used to differentiate the DOS rates. The lowest priority DOS rate — DOS 7 Minutes — would include no contribution to fixed costs, while higher priority DOS rates — DOS 1 Hour and DOS Term — would include increasingly larger contributions to fixed costs. Specific proposals are discussed later in this section.
- 35 (c) DOS customers should pay no costs associated with the interconnection POD component of the DTS rate, as all such costs are fixed in nature and the POD facilities are provided only to the extent DTS capacity is contracted for by the customers. (Any facility costs above those invested in based on DTS capacity are paid directly by the customer through customer contribution.)
- 40 (d) DOS customers should pay the variable costs associated with the operating reserve component of the DTS rate. The operating reserves carried by the AESO are determined in accordance with Western Electricity Coordinating Council (WECC) and North West Power Pool (NWPP) requirements regarding replacement of generating capacity and energy lost due to forced outages of generation or transmission equipment. As generation cannot be identified as serving opportunity loads, DOS
- 45

customers contribute to the AESO's requirement to carry operating reserves, and should therefore pay those costs like other load customers.

- 5 (e) DOS customers should pay no costs associated with the voltage control component of the DTS rate, as such costs relate to the procurement of Transmission Must-Run services and such services would not be procured in support of DOS loads.
- 10 (f) Similarly, DOS customers should pay no costs associated with the other system support component of the DTS rate, as such costs relate to the procurement of Under Frequency Mitigation and Poplar Hill services which would not be procured in support of DOS loads.

The resulting minimum costs attributable to DOS customers are summarized in Table 4.7.2.

15 *Table 4.7.2 2007 DTS Rate Components Attributable to DOS Loads, \$/MWh*

<u>DTS Rate Component</u>	<u>Attributable to DOS Loads</u>		
	<u>Fixed</u>	<u>Variable</u>	<u>Total</u>
Interconnection – System	-	2.42	2.42
Interconnection – POD	-	-	-
20 Operating Reserve	-	2.29	2.29
Voltage Control	-	-	-
Other System Support	-	-	-
Total	-	4.71	4.71

25 Table 4.7.2 provides a minimum DOS price that is appropriate for the DOS 7 Minutes rate. In order to establish a basis for setting the other DOS rates relative to DOS 7 Minutes, the distinctions between the different opportunity services offered by the AESO were examined.

30 Opportunity services are principally differentiated on curtailment provisions and qualifying criteria, with prices reflecting those criteria. DOS loads are curtailed in accordance with AESO OPP (Operating Policy and Procedures) 901 to prevent or alleviate abnormal conditions such as, but not limited to, low voltage levels, transmission facility overloads, equipment damage, abnormal frequency deviation, tripping of transmission facilities that could result in cascading outages, deficiency in ancillary services, or energy supply shortfall.

35 Of particular note are the curtailment provisions included in OPP 801 on supply shortfall; the DOS rate and OPP 801 curtailment provisions are as follows:

- DOS 7 Minutes — Recallable in 7 minutes per current AESO rate; curtailed with 7-minutes notice per step 7 of AESO OPP 801.
- 40 • DOS 1 Hour — Recallable in 1 hour per current AESO rate; curtailed with 1-hour notice per step 6 of AESO OPP 801.
- DOS Term — Recallable in 1 hour per current AESO rate; curtailed as directed by System Controller per step 8 of AESO OPP 801.

45 The curtailment provisions for reasons other than supply shortfall generally follow the provisions in OPP 801. All DOS loads are usually curtailed at or near the same time — in

5 OPP 801's case, as steps 6, 7, and 8 of a 30-step supply shortfall management procedure. (For reference, firm load is curtailed at step 29.) However, curtailment for supply shortfall differs from curtailment for other reasons, in that supply shortfall is a system-wide emergency while other reasons (such as low voltage levels or transmission facility overloads) generally affect a local transmission region. For regional emergencies, only one type of DOS load may be served, and there can as a result be no differentiation of DOS curtailment priority.

10 The AESO notes that in responding to a transmission emergency, curtailment is generally needed as quickly as possible to avoid the possibility of cascading outages or shedding of firm load. (If the emergency continues such that firm load shedding is required, such shedding occurs within moments of a directive being issued.) As a result, both DOS 7 Minutes and DOS Term loads are curtailed with 7-minutes notice under current AESO practice, and the rate sheets in this Application have been clarified to reflect this.

15 The AESO does not currently have any DOS 1 Hour customers. If such loads did exist and were required to be curtailed in a transmission emergency, the AESO would need to issue notice well in advance of expected need to maintain the 1 hour notice period. This might result in DOS 1 Hour customers being curtailed more frequently than DOS 7 Minutes customers. (Note that DOS 1 Hour notice actually occurs in Step 6 of AESO OPP 801, *prior to* DOS 7 Minutes notice in Step 7.) However, the AESO currently has only four DOS customers, and comparing curtailment frequencies between services is not practical.

20 Based on this determination, existing DOS loads are all curtailed at or near the same time to prevent or alleviate abnormal conditions on the transmission system, with the only distinction being that DOS 1 Hour loads, if any existed, would be curtailed in advance of and with somewhat longer notice than DOS 7 Minutes or DOS Term loads.

25 DOS loads are also differentiated on qualifying criteria in accordance with the AESO *Demand Opportunity Service Business Practices*. DOS 7 Minutes and DOS 1 Hour have the same qualifying criteria: the customer must have a short-term business opportunity that requires the use of additional energy which could otherwise be provided through an alternative source of energy (such as a gas drive) or would be foregone at the standard DTS rate. There is no differentiation between DOS 7 Minutes and DOS 1 Hour in terms of qualifying criteria.

30 During stakeholder consultation the AESO proposed that, based on the similar nature of curtailment provisions and qualifying criteria for DOS 7 Minutes and DOS 1 Hour, the DOS 1 Hour rate be eliminated in this Application. Stakeholders objected to this termination, and on further consideration the AESO accepts their recommendation that the rate remain available.

35 The AESO therefore proposes to include in the DOS 1 Hour rate a contribution to fixed costs equal to 50% of the \$/MWh amount associated with the DTS interconnection system fixed component. This represents a minimal contribution to costs as DOS customers incur no contract minimum or ratchet costs in hours in which they do not schedule capacity, and

approaches the \$2.00/MWh price differential between the current DOS 7 Minutes and DOS 1 Hour rates. This amount is shown in Table 4.7.3 to determine the DOS 1 Hour rate.

Table 4.7.3 2007 DTS Rate Components Attributable to DOS 1 Hour Loads, \$/MWh

DTS Rate Component	Attributable to DOS Loads		
	Fixed	Variable	Total
Interconnection – System	1.28	2.42	3.70
Interconnection – POD	-	-	-
Operating Reserve	-	2.29	2.29
Voltage Control	-	-	-
Other System Support	-	-	-
Total	1.28	4.71	5.99

DOS Term includes one qualifying criterion in addition to the DOS 7 Minutes and DOS 1 Hour criteria: the customer may require increased electrical consumption during planned maintenance of an on-site generator and would otherwise reduce load to avoid the ratchet on the standard DTS rate. As with all qualifying criteria, the onus is on the customer to make a convincing case for the use of DOS Term for generator maintenance, and assessing the case that the customer would otherwise reduce load has always been problematic for the AESO. At the same time, the AESO's consideration of the provision of backup service in section 4.6 of this Application resulted in the proposal to relax the qualifying criteria for DOS Term to permit its use for planned generator maintenance

Although the AESO proposes to relax the qualifying criteria for DOS Term, all DOS loads will continue to be curtailed in accordance with OPP 901 to prevent or alleviate abnormal conditions as listed earlier in this section. DOS remains interruptible, temporary, and available only when there is surplus transmission capacity. Standby use of an unplanned nature, including unplanned outages or derates of a generator, remains ineligible for DOS, including DOS Term. All DOS usage continues to require a qualifying application including system studies.

In extending the availability of DOS Term to all planned generator maintenance, the AESO proposes that the DOS Term price include a component that in effect converts the "system" ratchet charges incurred by loads above contract capacity into a usage (\$/MWh) charge which generates equivalent revenue over a typical maintenance period. Assuming annual generator maintenance of two to four weeks (that is, about one month or less), a 1 MW excursion above contract capacity would incur $(1 \text{ MW} \times 1 \text{ month}) + (1 \text{ MW} \times 90\% \times 11 \text{ months}) = 10.9 \text{ MW-months}$ of charges, to be recovered over the four-week period or 672 hours. The charge would be calculated as follows, based on the system demand component of the interconnection charge in the proposed DTS rate.

$$\text{\$1,176.00/MW} \times 10.9 \text{ MW} = \text{\$12,818.40}$$

$$\text{\$12,818.40} \div 672 \text{ MWh} = \text{\$19.08/MWh}$$

This rate would reflect recovery of the fixed component of system costs attributable to a customer over four weeks, and is shown in Table 4.7.4 to determine the DOS Term rate.

Table 4.7.4 2007 DTS Rate Components Attributable to DOS Term Loads, \$/MWh

	<u>DTS Rate Component</u>	<u>Attributable to DOS Loads</u>		
		<u>Fixed</u>	<u>Variable</u>	<u>Total</u>
5	Interconnection – System	19.08	2.42	21.50
	Interconnection – POD	-	-	-
	Operating Reserve	-	2.29	2.29
	Voltage Control	-	-	-
	Other System Support	-	-	-
10	Total	19.08	4.71	23.79

The DOS 7 Minutes, DOS 1 Hour, and DOS Term prices provided in the above discussion are included in the DOS rate schedules in section 7 of this Application. The AESO *Demand Opportunity Service Business Practices* will be revised to reflect the final determination of the EUB on the DOS rates, after the EUB’s decision on this Application is issued.

4.8 Export and Import Services

The AESO’s current tariff includes Export Opportunity Service (EOS) and Import Opportunity Service (IOS). In response to prior EUB directions and stakeholder interest, the AESO consulted with stakeholders on additional export and import services during 2004 and 2005. This consultation was discussed during the AESO’s 2005-2006 GTA proceeding, and in Decision 2005-096 the EUB encouraged the AESO “to continue the stakeholder discussions with interested parties on a go forward basis towards the potential development of firm import and export rates.” (p. 33)

During its stakeholder consultation in 2005, the AESO proposed a structure for export and import rates based on the components of comparable domestic service rates. Specifically, it was proposed that non-recallable (“firm”) rates be offered similar to non-recallable domestic rates, and additional opportunity rates be offered similar to domestic opportunity rates. Consultation concluded in late 2005 with a decision to defer further export and import rates development until the wholesale market review underway at the same time had progressed such that alignment with potential market changes could be assessed. Based on current expectations of market changes, the AESO believes the rate basis as proposed during consultation remains appropriate.

The AESO notes that in consultation some stakeholders requested an extensive selection of export rates — hourly, daily, weekly, monthly, and annual versions, for both non-recallable and opportunity service. However, the AESO understands that in neighbouring jurisdictions the majority of export transactions occurs on hourly, monthly, and annual rates, and has therefore proposed hourly and monthly opportunity export rates together with an annual non-recallable rate in this Application.

The AESO further notes that the proposed addition of multiple export rates with different priorities cannot be accommodated with existing inter-tie scheduling systems used by the AESO. An OASIS (Open Access Same-time Information System) or other system with

similar capabilities will be required to accommodate the additional rates, and the rates cannot be implemented before such a system is installed and commissioned.

The OASIS or similar system is required to manage the contracting and scheduling of capacity, allocation of ATC, release of unscheduled capacity, and curtailment of multiple export services on existing inter-ties and merchant interconnections to other jurisdictions. Procedures for these activities will be developed in the AESO's Operating Policies and Procedures (OPPs) consistent with current practice. OPPs generally include stakeholder consultation in their development, and the current versions of OPPs are publicly available on the AESO's website.

Based on the preceding considerations, the AESO has developed export and import rates that have a similar basis as proposed domestic service rates included in this Application. The AESO proposes export service rate structures with components as summarized in Table 4.8.1.

Export rate component charges are proposed to be based on similar component charges for the DTS rate. Similar to the AESO's DOS rate proposals, the AESO proposes that all export rate components will be charged on a usage (\$/MWh or percentage of pool price) basis. The AESO has therefore converted all components of its 2007 DTS revenue requirement into usage charges as if all were to be recovered on such a basis from all DTS customers, as provided in Table 4.8.2.

Table 4.8.1 Export Service Rate Structures

Service Name	Demand Transmission	Export Transmission	Demand Opportunity	Export Opportunity
Rate Code	DTS	XTS	DOS	XOS
System Charge	Postage Stamp	Postage Stamp	Incremental	Incremental
POD Charge	Postage Stamp	None	None	None
Losses	None	Location-Specific	Location-Specific	Location-Specific
Operating Reserve	Postage Stamp (% of Pool Price)	Postage Stamp (% of Pool Price)	Postage Stamp (\$/MWh)	Postage Stamp (\$/MWh)
Voltage Control	Postage Stamp	Postage Stamp	None	None
Other System Support	Postage Stamp	Postage Stamp	None	None
Curtailment (OPP 801)	Step 29	Just Prior to Step 29	Steps 6-8	Just Prior to Step 6
Contract Term	Minimum 5 Year	Minimum 1 Year	8 Hours to 1 Year	1 Hour to 1 Year

Table 4.8.2 Conversion of 2007 DTS Revenue Requirement in \$ 000 000 into Usage Amounts

DTS Rate Component	2007 Revenue Requirement			\$/MWh Based on 54,682.5 GWh		
	Fixed	Variable	Total	Fixed	Variable	Total
Interconnection – System	139.9	132.6	272.5	2.56	2.42	4.98
Interconnection – POD	188.6	-	188.6	3.45	-	3.45
Operating Reserve	-	125.2	125.2	-	3.33% × PP	
Voltage Control	-	50.8	50.8	-	0.93	0.93
Other System Support	7.8	-	7.8	0.14	-	0.14

10 The fixed and variable component of each DTS rate component was then examined in accordance with the structure presented in Table 4.8.1, to determine which costs should be included in export rates.

4.8.1 Export Transmission Service Rate XTS

15 The proposed Export Transmission Service Rate XTS is a non-recallable (“firm”) service similar to Rate DTS. Rate XTS will therefore be based on Rate DTS as follows.

- 20 (a) XTS rate components are generally set to be equivalent to DTS rate components expressed on a usage basis, except for the interconnection point of delivery (POD) charge.
- 25 (b) The AESO proposed in stakeholder consultation to reduce the Rate XTS interconnection system charge by the amount of the Demand Under-Frequency Load Shedding (UFLS) Credit for the 59.1 Hz relay trip setting, to recognize that XTS capacity will be curtailed prior to domestic load being shed under UFLS. The AESO has since determined such a reduction would be inappropriate.

30 Although exports would be curtailed before UFLS-connected load under a supply shortfall emergency, UFLS-connected load is also curtailed to maintain the stability of the transmission system in the event of other major system disturbances when exports would not be curtailed. The UFLS Credit compensates load customers for curtailment under more than system-wide supply shortfall conditions. The curtailment of XTS capacity would be more consistent with curtailment of non-UFLS-connected load, and Rate XTS should therefore not receive the UFLS Credit.

- 35 (c) Rate XTS does not include an interconnection POD charge as there are no “customer-related” facilities associated with export service.
- 40 (d) A minimum charge based on 90% of scheduled capacity applies to Rate XTS, in hours in which Available Transfer Capacity (ATC) exists to accommodate the scheduled capacity. This minimum charge is comparable to the 90% ratchet level applied in the determination of billing capacity in the DTS rate.
- 45 (e) Rate XTS includes a losses charge based on a location-specific loss factor determined for each point of exchange under ISO Rules. The ISO Rules do not currently provide for a loss factor for non-recallable export service in accordance with the current *Transmission Regulation*. The AESO understands proposed revisions to

the *Transmission Regulation* may in the future require losses charges for all export services, including non-recallable export service. In the event this becomes the case, the losses charge in proposed Rate XTS allows for the application of loss factors when required by the *Regulation*; until that time the loss factors for Rate XTS are set at 0.00%. Although this charge is provided for clarity in the XTS rate schedule, the AESO will be required to comply with applicable current legislation in any event.

- (f) XTS capacity will be curtailed immediately prior to curtailment of non-recallable domestic loads. For example, in a supply shortfall emergency, non-recallable domestic load is curtailed in Step 29 of OPP (Operating Policy and Procedures) 801; XTS capacity would be curtailed immediately prior to Step 29 of OPP 801.
- (g) XTS will require a minimum contract term of 1 calendar year. The same level of XTS capacity would be contracted for the full contract term, but would be available only in hours in which Available Transfer Capacity (ATC) exists to accommodate the scheduled capacity.

The AESO had initially proposed that scheduled capacity could be varied on a monthly basis under Rate XTS. On further review, the AESO considers that a uniform amount of capacity should apply for the full contract term. Such a commitment is appropriate when system planning decisions will include consideration of capacity contracted for under Rate XTS, and is comparable to capacity commitments under Rate DTS. However, in recognition of current constraints on ATC, no minimum charge is proposed to apply in hours in which ATC is unavailable for the scheduled capacity, in accordance with point (d) above.

The resulting costs attributable to Rate XTS, based on the above discussion and Table 4.8.2, are summarized in Table 4.8.3.

Table 4.8.3 2007 DTS Rate Components Attributable to XTS Capacity, \$/MWh

DTS Rate Component	Attributable to XTS Capacity		
	Fixed	Variable	Total
Interconnection – System	2.56	2.42	4.98
Interconnection – POD	-	-	-
Operating Reserve	-	3.33% × PP	
Voltage Control	-	0.93	0.93
Other System Support	0.14	-	0.14

The XTS rate schedule is included in the proposed tariff in section 7 of this Application

4.8.2 Export Opportunity Service Rates XOS 1 Hour and XOS 1 Month

Export Opportunity Service Rates XOS 1 Hour and XOS 1 Month are proposed to be recallable services similar to Demand Opportunity Service Rates DOS 7 Minutes and DOS Term. (The AESO notes that export service is scheduled “firm” within the hour, and therefore considers XOS 1 Hour to be a more appropriate name for the short-term export rate despite similarities to DOS 7 Minutes. In any event, all scheduled export capacity must be confirmed

at 20 minutes before the hour in accordance with AESO Operating Policies and Procedures (OPPs).)

XOS rates are therefore based on Rate DTS as follows:

5

(a) XOS customers will pay the variable costs associated with the interconnection system component of the DTS rate, as such variable costs are incurred on behalf of all users of the transmission system.

10

(b) XOS customers should pay a portion of the fixed costs associated with the interconnection system component of the DTS rate, as a contribution to fixed costs to reduce the level of average rates charged to other customers. The AESO proposes that XOS customers pay the same contribution to fixed costs as DOS customers — that is, the lowest priority XOS rate would include no contribution to fixed costs, while higher priority rates would include a contribution as discussed later in this section.

15

(c) XOS customers should pay no costs associated with the interconnection POD charge as there are no “customer-related” facilities associated with export service.

20

(d) As in the current Rate EOS, a minimum charge based on 75% of scheduled capacity applies to XOS rates, in hours in which Available Transfer Capacity (ATC) exists to accommodate the scheduled capacity.

25

(e) Rates XOS includes a losses charge based on a location-specific loss factor determined for each point of exchange under ISO Rules, as required under the *Transmission Regulation*.

30

(f) XOS customers should pay the variable costs associated with the operating reserve component of the DTS rate. In general, the originating control area is responsible for operating reserves required by interprovincial transactions, and for exports the originating control area is Alberta. The operating reserves carried by the AESO are determined in accordance with Western Electricity Coordinating Council (WECC) and North West Power Pool (NWPP) requirements regarding replacement of generating capacity and energy lost due to forced outages of generation or transmission equipment. As generation cannot be identified as serving opportunity loads, XOS customers contribute to the AESO’s requirement to carry operating reserves, and should therefore pay those costs like other export customers.

35

(g) XOS customers should pay no costs associated with the voltage control and other system support components of the DTS rates, as such costs relate to services which would not be procured in support of opportunity loads.

40

(h) XOS capacity will be curtailed immediately prior to curtailment of opportunity domestic loads. For example, in a supply shortfall emergency, opportunity domestic load is curtailed in Steps 6, 7, and 8 of OPP (Operating Policy and Procedures) 801; XOS capacity would be curtailed immediately prior to Step 6 of OPP 801.

45

- (i) XOS 1 Hour and XOS 1 Month require minimum contract terms of 1 hour and 1 month respectively. For XOS 1 Month, the same level of XOS capacity would be contracted for the full contract term, but would be available only in hours in which Available Transfer Capacity (ATC) exists to accommodate the scheduled capacity.

The resulting costs attributable to Rate XOS 1 Hour, based on the above discussion and Table 4.8.2, are summarized in Table 4.8.4.

Table 4.8.4 2007 DTS Rate Components Attributable to XOS 1 Hour Capacity, \$/MWh

<u>DTS Rate Component</u>	<u>Attributable to XTS Capacity</u>		
	<u>Fixed</u>	<u>Variable</u>	<u>Total</u>
Interconnection – System	-	2.42	2.42
Interconnection – POD	-	-	-
Operating Reserve	-	2.29	2.29
Voltage Control	-	-	-
Other System Support	-	-	-
Total	-	4.71	4.71

Rate XOS 1 Month has scheduling and curtailment priorities higher than XOS 1 Hour and lower than XTS, and should therefore be priced between those rates to reflect a value in accordance with those priorities. The AESO proposes that Rate XOS 1 Month pay the same contribution to fixed costs equivalent to that included in the DOS 1 Hour rate, namely 50% of the \$/MWh amount associated with the XTS interconnection system fixed component.

The resulting costs attributable to Rate XOS 1 Month, based on the above discussion and Tables 4.8.2 and 4.8.4, are summarized in Table 4.8.5.

Table 4.8.5 2007 DTS Rate Components Attributable to XOS 1 Month Capacity, \$/MWh

<u>DTS Rate Component</u>	<u>Attributable to XTS Capacity</u>		
	<u>Fixed</u>	<u>Variable</u>	<u>Total</u>
Interconnection – System	1.28	2.42	3.70
Interconnection – POD	-	-	-
Operating Reserve	-	2.29	2.29
Voltage Control	-	-	-
Other System Support	-	-	-
Total	1.28	4.71	5.99

The XOS rate schedules are included in the proposed tariff in section 7 of this Application

4.8.3 Import Rates

In stakeholder consultation on export and import rates the AESO initially proposed to develop non-recallable and opportunity import rates. However, non-recallable and opportunity distinctions do not exist for the AESO's domestic supply service, and there likewise appears to be no distinguishing features to differentiate on such a basis between import rates. Rate IOS recovers only the cost of losses and a transaction fee.

The AESO therefore proposes to continue Import Opportunity Service Rate IOS as currently approved.

4.9 Merchant Export and Import Services

During stakeholder consultation on export and import rates the AESO initially proposed to develop rates for export and import service over merchant transmission lines using a point-to-point model (rather than the “network service” model which forms the basis for the export and import rates discussed above). The AESO now proposes for the 2007 tariff that the network service model also apply to merchant services, consistent with other rates provided in Alberta.

However, the export rates discussed above include a contribution to the costs of the Alberta-British Columbia and Alberta-Saskatchewan inter-ties, which would not be utilized for energy transfers over a merchant line. (If a merchant transaction was scheduled with a corresponding inter-tie transaction for “wheel-through” energy flow into and out of Alberta, the inter-tie would be utilized for the corresponding transaction but not for the merchant transaction itself.) The AESO proposes that both fixed and variable wires costs attributable to the existing inter-ties be excluded from rates applicable to export over merchant inter-ties.

The costs associated with the Alberta-British Columbia and Alberta-Saskatchewan inter-ties are determined as follows based on the analysis of the costs of interprovincial ties in the *2006 Transmission Cost Causation Update*.

Figure 4.9.1 Conversion of Inter-tie Costs in \$ 000 000 into \$/MWh Amounts

DTS Component	2007 Revenue Requirement			\$/MWh Based on 54,682.5 GWh		
	Fixed	Variable	Total	Fixed	Variable	Total
Interconnection – System						
Inter-ties	18.7	17.7	36.4	0.34	0.32	0.67
Other System	121.2	114.8	236.0	2.22	2.10	4.32
System Total	139.9	132.6	272.5	2.56	2.42	4.98

The AESO has included Merchant Transmission Service Rate MTS and Merchant Opportunity Service Rates MOS 1 Hour and MOS 1 Month in the rate schedules provided in section 7 of this Application. These rate schedules are the equivalent of Rates XTS, XOS 1 Hour, and XOS 1 Month with costs associated with the existing inter-ties removed as shown in Schedule 5.8 in section 5 of this Application.

As inter-tie costs are not recovered through Import Opportunity Service Rate IOS, it will apply to imports over merchant transmission facilities without modification.

4.10 Primary Service Credit

The Primary Service Credit (PSC) in the AESO’s 2006 tariff was developed on a different basis than that which underlies the associated Point of Delivery (POD) charge in the DTS rate. The premise of the PSC is that it reduces the Point of Delivery charge to reflect customer ownership of transformation equipment in the substation, where such ownership

results in a reduction of investment by the TFO. However, detailed information on the transformation component of POD costs was not available during the 2006 tariff proceeding.

5 For this Application, the AESO proposes to align the form and level of the PSC with the POD charge in the DTS rate, and to extend eligibility to any interconnection which does not include TFO ownership of conventional transformation.

10 The level of the PSC was assessed in detail during the AESO's 2006 GTA proceeding, with its calculation based upon typical configurations the system would invest in to provide transmission service to a load customer. The EUB approved the level of \$660.00/MW/month in Decision 2005-096. The AESO proposes to maintain this level for 2007, adjusted to reflect changes to the POD-related revenue requirement and to align with the structure of the proposed POD charge, as follows.

15 The AESO's 2006 POD-related revenue requirement was approved as \$189.7 million, from Schedule 5.5 of the AESO's 2005-2006 Second Refiling dated December 9, 2005. The transformation costs within that revenue requirement can be estimated for all DTS customers as the PSC multiplied by the 2006 billing capacity determinant, namely
20 \$660.00/MW/month × 114,716.8 MW-months (from Schedule 5.8 of the Second Refiling) which equals \$75.7 million. Transformation costs are therefore estimated to be \$75.7 million ÷ \$189.7 million = 40% of POD-related costs.

25 The AESO therefore proposes that the level of the Primary Service Credit be established at 40% of the level of the POD charge in the AESO's proposed 2007 DTS rate. The structure of the PSC should follow the structure of the POD charge, such that the credit incorporates 40% of each component of the POD charge provided in section 4.5.2 of this Application, as follows:

- 30 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 Fraction

35 The proposed structure of the PSC differs from the simple \$/MW structure approved for 2006, but appropriately parallels the structure of the DTS POD charge. The AESO verified the result by calculating the credit an average customer would receive under the 2006 and proposed 2007 Primary Service Credits.

40 The average DTS capacity of customers currently receiving the PSC is 28 MW. The 2006 PSC for a 28 MW customer would be:

$$2006 \text{ PSC} = \$660.00/\text{MW} \times 28 \text{ MW} = \$18,480.00$$

The 2007 PSC for a 28 MW customer would be:

$$\begin{aligned} 2007 \text{ PSC} &= (\$1,252.00/\text{MW} \times 7.5 \text{ MW}) + (\$310.00/\text{MW} \times 20.5 \text{ MW}) + \$1,905.00 \\ &= \$17,650.00 \end{aligned}$$

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The small reduction in PSC is reasonable in light of the small reduction in POD-related charges in the AESO's 2007 tariff. As well, the change to the PSC structure will result in varying impacts on individual customers. Customers smaller than average will generally see an increase in the credit while customers larger than average will generally see a decrease in the credit. The application of the substation fraction will also vary the impact on individual customers.

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In addition to the level and structure changes, the AESO proposes that the eligibility criteria for the Primary Service Credit be refocused from whether the customer-owned transformation would have reduced TFO investment to whether the TFO owns conventional transformation equipment utilized in providing service to the customer. The AESO considers that such a change would appropriately accommodate the unconventional and "virtual" interconnections discussed in section 4.5.2 of this Application.

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However, the AESO continues to support the inclusion of an investment test when assessing the eligibility of an interconnection for the Primary Service Credit. The EUB indicated its agreement with such a principle when it noted in Decision 2005-096 that the PSC "should be related to the avoided average cost of system investment" (p. 38). This principle would be violated if the maximum investment was available for services where "average" facilities were not being provided by the TFO. The AESO therefore proposes that the maximum investment level be reduced by the 40% ratio determined above when conventional transformation equipment is not provided by the TFO, whether through customer ownership of transformation or through unconventional or "virtual" interconnections. This reduction is incorporated in the customer contribution calculation in Article 9.5 of the proposed terms and conditions of service, as discussed in section 6.5 of this Application.

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The AESO notes that an additional benefit of reorienting the focus of the investment test is a simplification of the eligibility criteria for the Primary Service Credit. The test no longer involves an estimate of TFO cost for transformation facilities which it will not supply. Eligibility is now determined based on the actual facilities the TFO will provide, with the reduction in investment reflected in the lower maximum investment level applicable when the TFO does not provide conventional transformation.

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The revised eligibility criteria is reflected in the PSC rate schedule in section 7 of this Application.

4.11 Other Rate and Rider Changes

The AESO proposes other minor changes to clarify or correct some aspects of the rate and rider schedules, as follows.

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(a) The ratchet period in the billing capacity calculation in the DTS rate has been clarified to be the 24-month period ending with the current billing period.

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(b) Changes related to the Rider F corrections applied for by the AESO in its October 12, 2006 application to the EUB (Application 1482458) have been included in the affected rate and rider schedules.

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(c) References to “location-specific loss factor” in the rate schedule now refer to the ISO Rule under which those loss factors are determined.

(d) The reference to “metered energy” in the IOS rate has been corrected to “energy transfer”.

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(e) Information related regulated generating units which was previously provided in Appendix B to the terms and conditions of service has been consolidated with the regulated generating units information already in the Rate Appendix.

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The balance of the rates and riders remain unchanged from those approved in the AESO’s 2005-2006 GTA Second Refiling. A blackline comparison of the current and proposed rates is included in Appendix H to this Application.