

## SECTION 4 2007 RATE DESIGN

5 In its 2006 tariff application, the AESO proposed significant changes to rates 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.

10 This 2007 tariff application also proposes changes to rates, some of which are also significant. However, there is no primary source (such as the *Transmission Regulation*) which is causing the 2007 rate changes. 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.

15 However, as the AESO conducted the stakeholder consultation (described in more detail in section 8 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 2006 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.

25 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 2006 rates. The fundamental rationale underlying the rates remains 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.

The specific rate changes proposed in this application include:

- 35 • re-integration of the bulk system and local system charges in the DTS rate into a single system charge based on billing capacity;
- 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;
- 40 • elimination of the DOS 1 Hour rate based on lack of differentiation from the DOS 7 Minutes rate, changes to qualifying criteria for the DOS Term rate, and changes to DOS rate levels to reflect current transmission system costs;
- introduction of non-recallable Export Transmission Service Rate XTS and recallable Export Opportunity Service Rate XOS 1 Month;
- 45 • 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.

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 consistent utilization of the substation fraction, and by accommodating changes to the Primary Service Credit in the customer contribution policy.

Schedules 5.1 through 5.12 accompany this rate design section. The format of rate calculations in the schedules follows the format used in the AESO's 2006 tariff application.

The net impacts on rates of the changes detailed in this Application are an overall decrease of 0.9% in the Demand Transmission Service (DTS) rate and an overall decrease of 1.9% 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	(0.5%)	-
Losses Charge	-	(4.5%)
Operating Reserve Charge	(4.4%)	-
Voltage Control Charge	4.1%	-
Other System Support Services Charge	3.9%	-
Regulated Generating Unit Connection Costs	-	(6.7%)
<b>Total Tariff</b>	<b>(0.9%)</b>	<b>(4.8%)</b>

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

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**

5 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**

10 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;*

15 (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.*

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**ISO tariff - transmission system considerations**

25 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*

30 (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;*

35 (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;*

40 (c) *consider all just and reasonable costs related to arrangements and agreements described in section 9(5) of the Act.*

45 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 on the ESBI Alberta Ltd. 1999/2000 General Rate Application Phase 1 and Phase 2.

5 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).

10 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.

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

## 15 **4.2 Rate Design Principles**

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, Danielsen, and Kamerschen, 2nd ed., 1988, pp. 385-389):

- 20 (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;
- (iii) Fairness, objectivity, and equity that avoids undue discrimination and minimizes inter-customer subsidies;
- 25 (iv) Stability and predictability of rates and revenue; and
- (v) Practicality, such that rates are appropriately simple, convenient, understandable, acceptable, and billable.

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

35 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.

40 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.

45 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 Functionalized and Classified Transmission 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
<b>Total</b>	<b>\$352.6</b>	<b>\$231.2</b>	<b>\$ 38.3</b>	<b>\$ 83.1</b>

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 Functionalized and Classified Transmission 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%
<b>Total</b>	<b>100.0%</b>	<b>65.6%</b>	<b>10.9%</b>	<b>23.6%</b>

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:

- 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.*  
(p. 23)

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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.* (p. 23)

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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.  
20 The *2006 Transmission Cost Causation Update* is provided as Appendix C to this Application.

#### 4.3.1 Transmission Cost Functionalization

25 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. 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:

- 30
- the functionalization of costs to local system and point of delivery (POD) in the cost study, and
  - the differentiation of system-related and customer-related costs in the AESO's terms and conditions of service.

35 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  
40 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  
45 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 Functionalized and Classified Transmission 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
<b>Total</b>	<b>\$352.6</b>	<b>\$232.6</b>	<b>\$ 38.9</b>	<b>\$ 81.1</b>

Note: Totals may not add due to rounding

Table 4.3.4 Functionalized and Classified Transmission 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%
<b>Total</b>	<b>100.0%</b>	<b>66.0%</b>	<b>11.0%</b>	<b>23.0%</b>

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).

5 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 eighty 240 kV bulk transmission lines in Alberta (weighted by line  
10 length) showed only a 9% 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 2%  
correlation with AIL.

15 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:

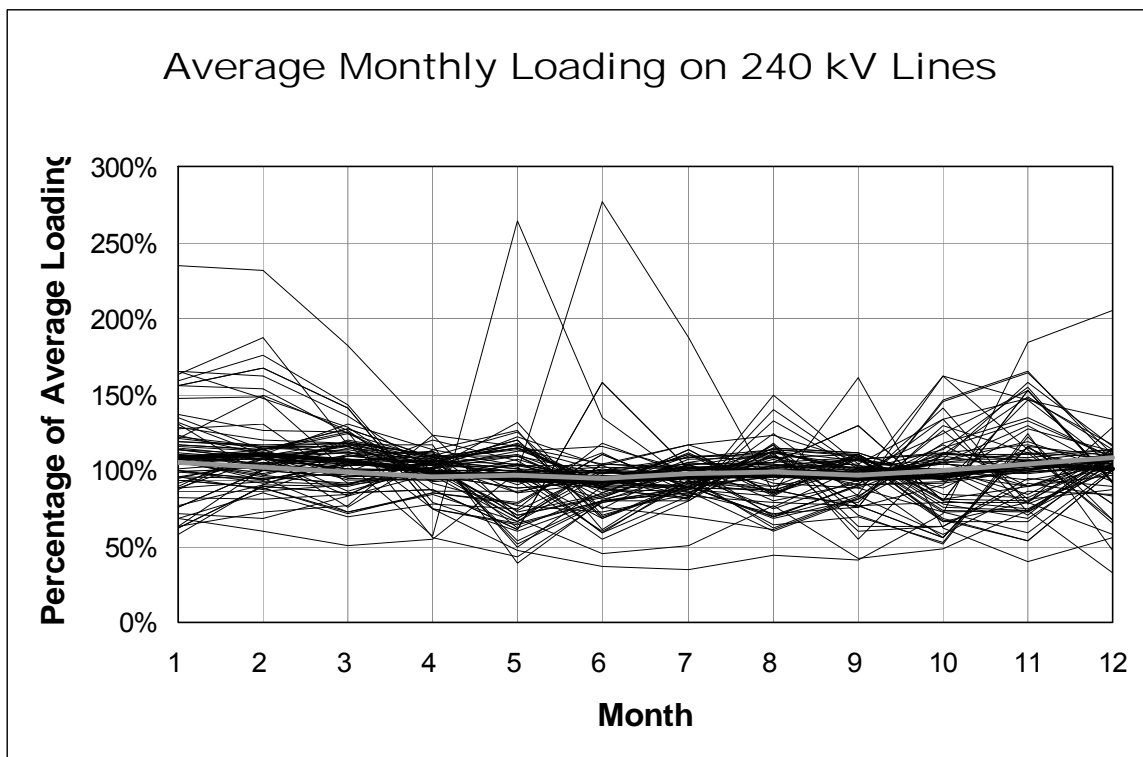
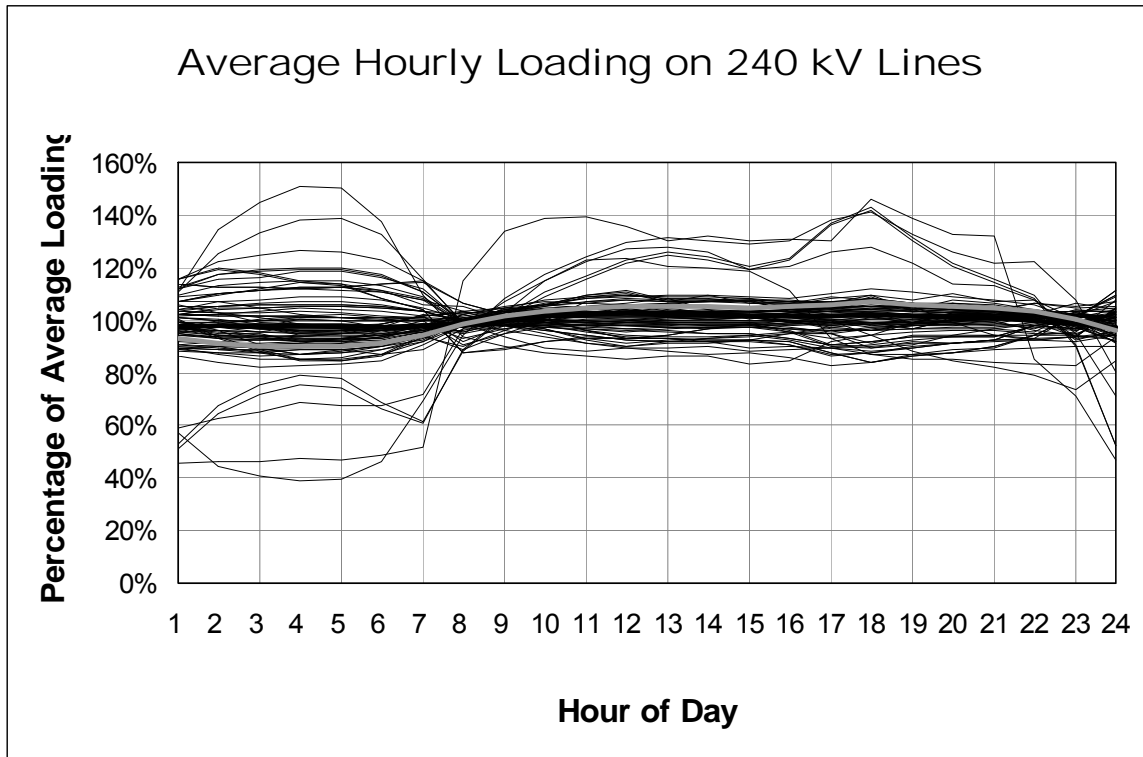
- None of the 240 kV lines experienced their monthly peaks during the times of AIL  
monthly peaks.
- During the hour of annual AIL peak, lines were loaded at about 60% of their annual peak  
20 load on average.
- During the hour of annual AIL peak in 2005, only four of the eighty 240 kV lines were 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

25 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 on a cost  
causation basis. 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  
30 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.

35 Figure 4.3.5 provides average daily and monthly profiles of loading on each of the eighty  
240 kV bulk transmission lines in the AIES, as well as the daily and monthly profile of AIL  
(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  
40 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.

45 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.

Figure 4.3.5 Average Bulk Line and AIL Loading in 2005



5 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.

10 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.

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

20 The AESO also reviewed the profiles and discussion in Appendix D 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.

25 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 (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.

35 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 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 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.

5 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 has 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*. The review is expected to be completed by mid-October. The AESO will provide the results of the review to stakeholders when it is completed, and will incorporate any necessary changes into the 2007 tariff application before filing.

10 After concluding that recovering bulk system costs on a coincident peak basis cannot be justified on a cost causation basis, 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 recovery on billing capacity is the most appropriate approach.

20 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, as well as general hour-by-hour variations over the year.

30 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.

35 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.

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

future loads on the system as indicated in part by customers' contracted capacity, the AESO considers that bulk system billing should include a contract capacity component.

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

10 The AESO notes that the characteristics of the bulk transmission system discussed in this section — relatively flat average loading, with no distinct hourly or monthly patterns — may be unusual (although a thorough assessment cannot be done because of the lack of similar detailed analysis in other jurisdictions). However, the AESO considers those characteristics to indicate a well-utilized and appropriately-designed bulk transmission system. It is reasonable to expect that this outcome has resulted, in part, from the price signals embedded in historical transmission cost recovery. Prior to 2006, the demand component of bulk transmission system costs have been primarily recovered billing capacity basis — that is, a combination of highest metered demand, contract capacity, and ratchet. This price signal appear to have been effective. The AESO therefore suggests that returning to such a billing determinant will continue to provide a price signal to customers which will retain those current favourable transmission system characteristics.

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25 With respect to the specific moderation of the demand charge questioned in Direction 4C, the AESO considers that it remains appropriate to reduce the demand related classification of the bulk system to account for diversity of POD loads and lack of coincidence of individual POD loads with maximum stress on bulk system components. Although the previous discussion explained that maximum metered demand in any hour or month is an appropriate billing determinant, the AESO recognizes that not all customer loads peak at the same time and the bulk system is designed and built with that expectation. It is therefore appropriate to reduce the demand related classification of the bulk system to reflect this.

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35 The reduction is calculated based on total customer load at the time of maximum loading on each bulk line. AIL is used to represent total customer load, with peak AIL indicating peak load for all customer. The percentage of peak AIL at the time of maximum loading on each bulk line was simply averaged for all bulk lines and weighted by line length. The average value resulting is 80.9%, and the demand-related classification of bulk system costs is accordingly reduced to 27.5%, calculated as 80.9% times the 34.0% presented in Table 4.3.4. The usage-related classification of bulk system costs is accordingly increased to 14.2%.

### 4.3.3 Operations, Maintenance, and Administration Costs

45 In responding to Direction 4D of Decision 2005-096, PS Technologies reviewed the functionalization and classification of operations, maintenance, and administration (OMA) costs within the *Transmission Cost Causation Study*. The *Update* considered that OMA costs could vary by equipment vintage and type, but noted that data was not available to

refine the functionalization and classification of OMA costs. In any event, the *Update* concluded the impact on total cost functionalization and classification would be expected to be small because OMA costs account for about one-quarter of TFO revenue requirements, all equipment involves a similar mix of vintages, and the largest cost function (bulk system) contains relatively equal amounts of line and substation equipment. No changes to the transmission cost functionalization and classification were recommended as a result of the review of OMA costs.

#### 4.3.4 Transmission Point of Delivery Cost Classification

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

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

Analysis of point of delivery cost data in the *Customer Contribution Study* found that those costs can be reasonably represented by the following cost function:

$$\begin{aligned} \text{Point of Delivery Costs} &= \$2.296 \text{ million} \\ &+ (\$0.279 \text{ million/MW} \times \text{first 17 MW of DTS Capacity}) \\ &+ (\$0.154 \text{ million/MW} \times \text{DTS Capacity above 17 MW}) \end{aligned}$$

This cost function is based on detailed examination of 30 projects representing a total DTS capacity of 516.7 MW and total project costs of \$213.2 million.

Establishing the appropriate customer-related component of the POD charge — represented by the \$2.296 million in the above cost function — proved particularly challenging. The customer-related component represents that portion of a transmission interconnection related to a hypothetical no-load customer. A minimum-intercept method to establish such a component is generally considered "more accurate" than other methods for distribution cost classification (see, for example, the NARUC *Electric Utility Cost Allocation Manual*, January 1992, p. 92), and the AESO adapted that appropriate to classify POD costs. The minimum-intercept approach relates installed cost to capacity, creates a curve for various capacities

using regression techniques, and extends the curve to a no-load intercept. This was the approach used to establish the point of delivery cost function provided above.

The AESO further tested the customer-related component by comparing it to least cost estimates for stand-alone DTS services of 5 MW or less which were prepared as part of the analysis of Customer-Owned Substation Credits provided in the AESO's 2005-2006 GTA. The average cost for the 12 projects was \$2.15 million, with regression analysis indicating a y-intercept of \$2.141 million and an almost flat slope of \$0.007 million/MW. The AESO considers the \$2.141 million y-intercept of the least cost estimates for these small projects to support the AESO's proposed minimum-intercept amount of \$2.296 million.

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 AESO therefore proposes the classification of POD costs based on the cost function provided above, as provided in Table 4.3.6.

Table 4.3.6 Classification of Point of Delivery Costs

Cost Component	Customer	≤ 17 MW	> 17 MW	Total
Unit Cost (\$ 000 000)	\$2.296	\$0.279	\$0.154	
Billing Determinant	5,004.4	65,357.8	53,571.6	
Total Costs (\$ 000 000)	\$11,490.1	\$18,255.4	\$8,261.1	\$38,006.6
Classification	30.2%	48.0%	21.7%	100.0%

The AESO therefore proposes to classify point of delivery costs 30.2% as customer-related and 48.0% + 21.7% = 69.7% 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%	22.2%	19.5%	-
Local System	17.4%	14.3%	3.0%	-
POD	40.9%	28.6%	-	12.4%
<b>Total</b>	<b>100.0%</b>	<b>65.1%</b>	<b>22.5%</b>	<b>12.4%</b>

Note: Totals may not add due to rounding

These findings are reflected in the cost classification in Schedule 5.3 in section 5 of this Application.

#### 4.4 Ancillary Services Cost Classification

The classification of ancillary services costs were 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.

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

The AESO's 2006 DTS rate was significantly unbundled from the prior DTS rate. In this application the AESO proposes rebundling two charges and simplifying others.

##### 4.5.1 DTS Interconnection — System Charge

Specifically, the AESO proposes rebundling 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
- a single charge will provide a clearer and simpler price signal to customers.

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.

Based on additional investigation conducted as part of the *Transmission Cost Causation Update* and discussed 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 thus allows the bulk system and local system charges to be combined into 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 would also better align with the AESO's contribution policy which differentiates only between system-related and customer-related costs. The system charge rate level is based on the results of the original *Transmission Cost Causation Study* and the 2006 *Transmission Cost Causation Update*, and recovers the 2007 bulk and local system components of wires charges.

#### 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) components, based on the revised classification discussed in section 4.3.4 of this application. With respect to the point of delivery charge, the EUB provided the following direction in Decision 2005-132:

6. *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 load services interconnected 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 above analysis is provided in response to part 1 of Direction 6 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 small load services have not been interconnected in recent history. Specifically, no load services smaller than 7.5 MW have been interconnected since 1999 nor are any currently being interconnected. The AESO therefore has been unable to quantitatively assess whether the costs of substations serving small loads would differ from the cost of substations serving larger loads. However, the AESO is not aware of any specific reason to expect that average costs for smaller loads would be significantly different from the function provided above, provided that the loads are interconnected through typical substation and line facilities.

The *Customer Contribution Study* also examined point of delivery costs above and below various breakpoints for the data included in the *Study*. Although there appeared to be no clear breakpoint which provided higher correlation factors both above and below the breakpoint, 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 a minimum-intercept analysis should be used to determine the minimum fixed costs attributable to a project. Based on total project costs, the AESO concluded that customer-related costs for interconnection project standard facilities could be reasonably represented by the following "raw" cost function:

$$\begin{aligned} \text{Point of Delivery Costs} = & \$2.296 \text{ million} \\ & + (\$0.279 \text{ million/MW} \times \text{first 17 MW of DTS Capacity}) \\ & + (\$0.154 \text{ million/MW} \times \text{DTS Capacity above 17 MW}) \end{aligned}$$

5 The AESO also notes that the data in the *Customer Contribution Study* analysis reflects two inherent characteristics: the projects represent recent history, and the projects were interconnected through typical substation and line facilities. Although there are no services smaller than 7.5 MW in the recent history data set used for the *Study*, 166 services with DTS capacities of less than 7.5 MW currently exist on the transmission system. Although comprehensive data is not available on all of these small services, the AESO understands that many of them are interconnected through conventional transmission substation and line facilities. For example, about two-thirds of substations with contract capacities of less than 7.5 MW utilize transformers from 7.5 MVA to 25 MVA (and sometimes larger) in size, which would generally be considered a conventional transmission substation.

10 However, some small services do have unusual characteristics:

- 15 (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 likely close to a transmission line and distant from a distribution line at the time of interconnection. 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.
- 20
- 25 (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.
- 30

35 Other small loads are served through conventional interconnections to the transmission system which were built when utilities were vertically-integrated, and the AESO has been unable to determine project costs for such interconnections. However, a reasonable assumption is that, since a distribution network can generally serve loads up to 7.5 MW, a transmission interconnection was likely a less expensive alternative for the specific circumstances at the time (possibly due to proximity to the transmission system). At the same time, these interconnections would have incurred “normal” costs for their conventional substations, although those costs would likely approach those for the “hypothetical no-load customer” discussed previously in section 4.3.4 above. In other words, the transmission interconnection would likely have been less expensive than a distribution connection, but not necessarily less expensive than the customer cost established through a minimum-intercept analysis.

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The AESO therefore concludes that the existing small (up to 7.5 MW) load services are appropriately represented by the “raw” cost function developed in the *Customer Contribution*

Study and discussed above, except where those small load services have unconventional interconnections as discussed in points (a) and (b) above. The AESO also notes that the “raw” cost function for smaller services is closer to a minimum cost function than an average cost function.

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Where small loads are served through unconventional interconnections, the AESO concludes they likely should be represented by a cost function which is different from and lower than that the “raw” cost function.

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The above discussion is provided in response to parts 2 and 3 of Direction 6.

As discussed above, existing small (up to 7.5 MW) load services with conventional interconnection are expected to represent more of a minimum than average cost function. The AESO therefore believes that the use of a minimum-intercept analysis to determine the *Customer Contribution Study* cost function also provides an appropriate basis for the Point of Delivery Charge in the DTS rate design, and has developed the Point of Delivery charge on this basis.

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During stakeholder consultation the AESO 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 current 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.

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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. In the AESO’s opinion, the final cost function developed in the *Customer Contribution Study* provides a sound basis for the POD charge. The customer (\$/month) component of the cost function is additionally supported by the least cost estimates for small services provided in the AESO’s 2005-2006 GTA, as discussed in section 4.3.4 above.

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In conclusion, the AESO considers that the three-part cost function discussed above addresses concerns about the cost function for small services, mitigates rate impacts that could occur with other rate approaches, and would be applicable to all customers with conventional interconnections. The AESO has therefore not proposed a “grandfathered” transmission service rate in this Application.

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Part 4 of Direction 6 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 customer are appropriately determined through application of the Primary Service Credit and the substation fraction, as discussed in section 4.10 of this Application.

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In recognition of the small services with unusual characteristics discussed in points (a) and (b) above, the AESO recommends this question be broadened 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:

- 5 • 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
- 10 • other unusual interconnections such as those taking service at transmission voltage.

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.

#### 4.5.3 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:

20 “...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.”

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.

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

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)*

5 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 its tariff application.

10 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:

15 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,

20 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.

25 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.

#### 30 **4.6 Backup or Standby Rate**

35 Prior to the preparation of its 2005-2006 tariff application, the AESO was approached by customers about providing a backup or standby transmission service suitable for loads that are of short-duration and infrequent in nature. The requirement for such a rate was raised during the AESO’s 2005-2006 GTA proceeding itself, and the AESO committed to examining the requirement for a backup or standby rate in its next tariff application.

40 A backup or standby rate is generally available to customers with onsite non-emergency generation, sometimes referred to as “partial-requirements customers”. 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):

1. *Backup or standby service* serves a customer load that would otherwise be fully served by onsite generation during unscheduled outages of the onsite generation.
2. *Supplemental service* is for customers whose onsite generation does not meet all of their needs.

3. *Scheduled maintenance service* is taken when a customer's onsite generation is planned to be out of service for maintenance or repair.
- 5 4. *Economic replacement service* is offered at times when the cost of producing and delivering electricity are less than that of the onsite generation.

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

- 10 • Supplemental service is available under the "full requirements" DTS rate, since it represents an ongoing and recurring service requirement.
- 15 • Scheduled maintenance service 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*).
- Economic replacement service is generally available under any DOS rate.

20 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.

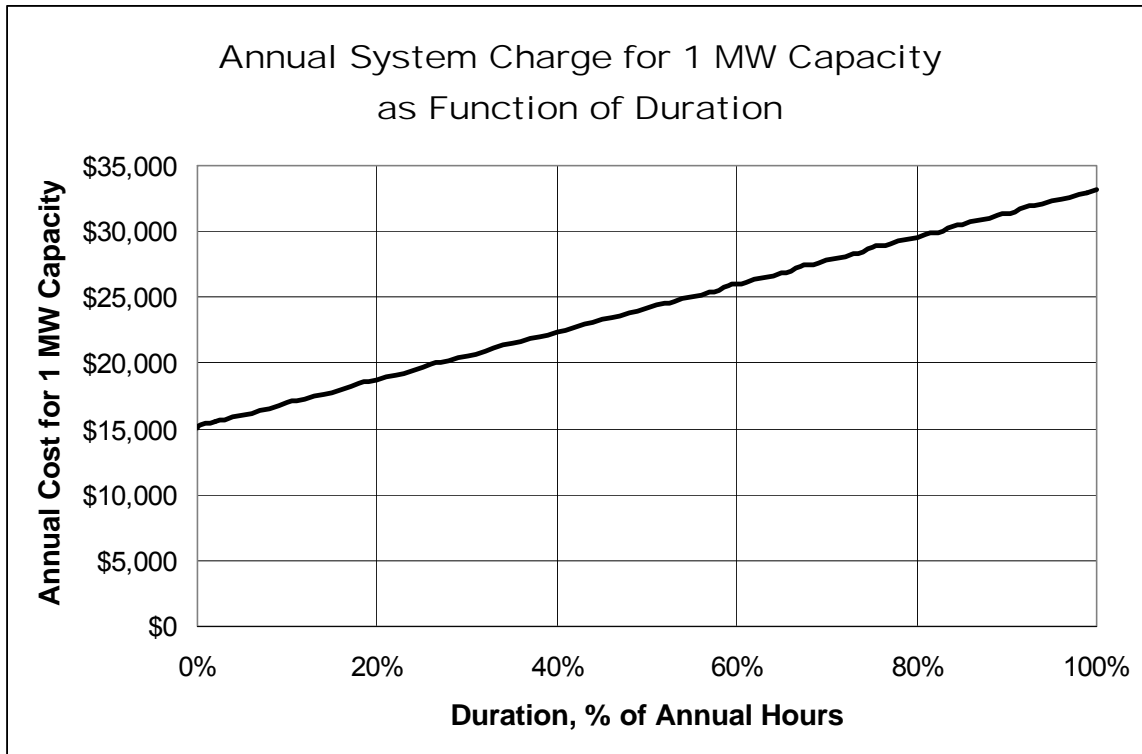
25 The "partial-requirements" category which is not accommodated under existing rates is backup or standby service. The distinguishing feature of such service is that it is required for periods of short duration no more than a few times per year and is unable to be predicted or scheduled with certainty. Backup or standby service is generally required to allow a load

30 process to continue uninterrupted when on-site generation suffers an unexpected outage.

35 Although there is no special provision for backup or standby service in the current DTS rate, such use of the transmission system is not currently prevented in any manner (except by capacity or other system constraints). The primary concern as the AESO understands it is that the current DTS rate results in charges which some stakeholders feel may be significantly higher than the costs imposed on the transmission system by backup or standby usage. The principle cost is the 2-year 90% ratchet component of billing capacity used in the recovery of demand-related costs. The ratchet imposes an on-going charge in the months following usage of the transmission system for backup or standby service. For

40 example, Figure 4.6.1 illustrates the annual system charges that accrue under DTS service as a result of different durations of use for a 1 MW load: usage for one hour a year incurs an annual cost of \$15,207 under the proposed 2007 DTS rate, while continuous usage for 8,760 hours a year incurs an annual cost of \$33,121.

Figure 4.6.1 Annual System Charge for 1 MW Capacity Under Proposed DTS Rate



5 Under the billing capacity provisions of the DTS rate, customers who require backup or standby service generally respond to the rate structure in two ways:

- They contract for the capacity needed during the backup or standby 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 or standby load conditions, and incur higher probability that constraints may exist at those times.

10 In either case, customers who require backup or standby service incur charges above those which would otherwise 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 as characterized by the short-duration and infrequent need for backup or standby service.

15 In general, the AESO found that short-duration, infrequent use does not give rise to long-term or short-term costs on the transmission system. Discussions with AESO system planning and operations planning suggest 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. This conclusion assumes a small number of such loads in any specific planning area, and reasonable diversity of the timing of such loads in an area. However, particular concern was expressed about the Fort McMurray area where a number of loads would be

expected to request standby or backup service, and where the assumed diversity may not exist.

5 Given the conclusion reached, the AESO proceeded to develop a rate to reflect cost  
causation attributable to short-duration, infrequent use of the transmission system, and  
presented Backup Transmission Service Rate BTS as part of the stakeholder consultation  
conducted during development of the 2007 tariff application. Rate BTS in effect converted  
the ratchet charges incurred by loads above contract capacity into a usage (\$/MWh) charge  
10 which generated equivalent revenue at a 10% load factor. For load factors below 10%, lower  
charges would be incurred on Rate BTS than on Rate DTS, and for load factors above 10%,  
higher charges would be incurred on Rate BTS. From a cost perspective this structure would  
reasonably recover costs attributable to short-duration, infrequent use of the transmission  
system while providing a price signal that would prevent inappropriate use of the rate.

15 Stakeholders who provided comments on the proposed Rate BTS generally supported it. At  
the same time, the AESO continued to review the details of the rate within the AESO. During  
this detailed review significant concerns were raised about the unscheduled nature of the  
service. The AESO understands that a key attribute of Rate BTS that standby customers are  
looking for is that it be available without specific prior approval; it is the same attribute that is  
20 of greatest concern to the operations and reliability group within the AESO.

The operations and reliability group expressed significant concern with any rate which might  
encourage one or more customers in a local or regional area to increase loading on the  
transmission system above normally forecast levels. From an operating perspective,  
25 unforecast and unscheduled loading on the transmission system could create 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. It was recognized that  
the current Rate DTS allows unscheduled usage, but the ratchet charges which are incurred  
with such usage generally discourage it. Reducing the charges to a lower level would  
30 encourage unscheduled loading and result in unacceptable risks for system operations and  
reliability.

To attempt to quantify this risk the AESO examined 2005 billing history for DTS customers.  
About 50 customers with load factors less than 10% and totaling about 600 MW of contract  
35 capacity would be expected to request switching from Rate DTS to Rate BTS. An additional  
50 customers who occasionally exceed contract capacity would also be expected to request  
switching of as much as 800 MW of capacity from Rate DTS to Rate BTS. Other customers  
could also minimize charges through an optimal choice of contract capacity and backup load  
service. In all, the AESO would expect potential requests from customers for 1,500 to  
40 2,000 MW of load on standby or backup service. Many of these customers are likely to be  
concentrated in areas where concurrent use may be a problem. The AESO considers that  
encouraging that quantity of unscheduled loading creates unacceptably high risks for  
transmission system operations and reliability.

45 Although Rate BTS may appropriately allocate the cost of transmission system facilities to  
customers, it results in unquantifiable costs associated with increased risks of system  
failure. The AESO therefore will not offer Rate BTS as initially proposed to stakeholders, but

continues to consider how a backup or standby service rate may be structured to ensure reliability is not jeopardized. In the mean time, the AESO concludes the current contract capacity and ratchet structure of Rate DTS is a reasonable approach which balances facilities costs and risk mitigation.

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The AESO also examined the need for scheduled 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 modifications to DOS Term in this Application to accommodate scheduled generator outages which should address this customer need while avoiding unscheduled loading and its associated risk of system failure. Additional information on the revised DOS rates is included in section 4.7 of this Application.

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Beyond the changes to DOS Term, the AESO does not consider it appropriate to offer a backup or standby service as part of this Application. Rate DTS as included in this Application is a reasonable approach which balances facilities costs and risk mitigation. However, it may be appropriate to revisit the AESO's risk concerns after the significant transmission system reinforcements currently in the planning stages are completed in accordance with the AESO's *10-Year Transmission System Plan*.

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#### 4.7 Demand Opportunity Service Rates

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 1999-2000 General Tariff Application of ESBI Alberta Ltd. (EAL):

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*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 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.*

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*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 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*

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*to see the use of screening criteria that would prohibit the beneficial use of opportunity service. (pp. 225-226)*

The premise of opportunity service is that it 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.

*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	165.8	102.1	268.0	3.03	1.87	4.90
Interconnection – POD	185.5	-	185.5	3.39	-	3.39
Operating Reserve	-	132.7	132.7	-	2.43	2.43
Voltage Control	-	55.6	55.6	-	1.02	1.02
Other System Support	8.0	-	8.0	0.15	-	0.15
Total	359.3	290.4	649.7	6.57	5.31	11.88

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.

- (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.
- (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. As a proxy, the AESO suggests DOS customers pay 50% of the \$/MWh amount associated with the interconnection system fixed component, recognizing that 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.
- (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.)

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

*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	1.52	1.87	3.38
Interconnection – POD	-	-	-
Operating Reserve	-	2.43	2.43
Voltage Control	-	-	-
Other System Support	-	-	-
<b>Total</b>	<b>1.52</b>	<b>4.29</b>	<b>5.81</b>

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.

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. 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.
- 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.

5 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 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  
10 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.

15 The AESO has also determined that the 1-hour notice provisions of DOS 1 Hour are impractical. In responding to a transmission emergency, the System Controller cannot wait an hour for DOS loads to respond. Curtailment is 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  
20 7-minutes notice under current AESO practice, and the rate sheets in this Application have been clarified to reflect this.

25 The AESO does not currently have any DOS 1 Hour customers. If such loads did exist, the AESO would also require curtailment of those loads within 7 minutes.

30 Based on this determination, DOS loads are all curtailed at or near the same time to prevent or alleviate abnormal conditions on the transmission system, and all are (or would be) curtailed with the same 7-minutes notice. Therefore there is no apparent basis for differentiating DOS on curtailment provisions.

35 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.

40 Based on the identical nature of curtailment provisions and qualifying criteria for DOS 7 Minutes and DOS 1 Hour, the AESO therefore proposes to eliminate DOS 1 Hour in this Application.

45 DOS Term includes one qualifying criterion in addition to the DOS 7 Minutes 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 examination of costs related to the provision of backup or standby service in section 4.6 of this Application resulted in the conclusion that costs related to short-term, infrequent use of the transmission system were low, although the unscheduled nature of backup service created unacceptable levels of risk. Planned generator maintenance is not unscheduled, however, and the AESO therefore proposes 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 to base the DOS Term price on a similar basis as initially suggested for the backup or standby rate. That is, DOS Term will 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 at a 10% load factor. Assuming annual generator maintenance, a 1 MW excursion above contract capacity would incur (1 MW × 1 month) + (1 MW × 90% × 11 months) = 10.9 MW-months of charges, to be recovered over 10% of a year or 876 hours. The charge would be calculated as follows, based on the system demand component of the interconnection charge in the DTS rate.

$$\$1,395.00/\text{MW} \times 10.9 \text{ MW} = \$15,205.50 \quad (\text{eq. 4.X.1})$$

$$\$15,205.50 \div 876 \text{ MWh} = \$17.36/\text{MWh} \quad (\text{eq. 4.X.2})$$

This rate would reflect recovery of the fixed component of system costs attributable to a customer at 10% load factor, and would replace the equivalent amount in Table 4.7.2 to determine the DOS Term rate as provided in Table 4.7.3.

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

DTS Rate Component	Attributable to DOS Loads		
	Fixed	Variable	Total
Interconnection – System	17.36	1.87	19.23
Interconnection – POD	-	-	-
Operating Reserve	-	2.43	2.43
Voltage Control	-	-	-
Other System Support	-	-	-
Total	17.36	4.29	21.65

The DOS 7 Minutes 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 Rates

5

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  
10 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)

15

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 opportunity domestic 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  
20 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.

25

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 occur 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.

30

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) will be required to accommodate the additional rates, and the rates cannot be implemented before such an  
35 OASIS is installed and commissioned. The AESO currently plans to have an OASIS available for the proposed effective date of the 2007 tariff, but notes that if the OASIS implementation is delayed the additional export rates cannot be offered until the OASIS is available.

40

The OASIS 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  
45 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.

5

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

10

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.

15

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	165.8	102.1	268.0	3.03	1.87	4.90
Interconnection – POD	185.5	-	185.5	3.39	-	3.39
Operating Reserve	-	132.7	132.7	-	3.70% × PP	
Voltage Control	-	55.6	55.6	-	1.02	1.02
Other System Support	8.0	-	8.0	0.15	-	0.15

20

25

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

30

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.

(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.

5

(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.

10

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.

15

(c) Rate XTS does not include an interconnection POD charge as there are no “customer-related” facilities associated with export service.

20

(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.

25

(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.

30

35

(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.

40

(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.

45

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	3.03	1.87	4.90
Interconnection – POD	-	-	-
Operating Reserve	-	3.70% × PP	
Voltage Control	-	1.02	1.02
Other System Support	0.15	-	0.15

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:

- (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.
- (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, 50% of the \$/MWh amount associated with the interconnection system fixed component, recognizing that this represents a minimal contribution to costs as XOS customers incur no contract minimum or ratchet costs in hours in which they do not schedule capacity.

- (c) XOS customers should pay no costs associated with the interconnection POD charge as there are no “customer-related” facilities associated with export service.
- 5 (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.
- 10 (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*.
- 15 (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.
- 20 (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.
- 25 (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.
- 30 (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.
- 35

The resulting costs attributable to Rate XOS 1 Hour, based on the above discussion and Table 4.8.2, are summarized in Figure 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	1.52	1.87	3.38
Interconnection – POD	-	-	-
Operating Reserve	-	2.43	2.43
Voltage Control	-	-	-
Other System Support	-	-	-
<b>Total</b>	<b>1.52</b>	<b>4.29</b>	<b>5.81</b>

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 an additional contribution to fixed costs equivalent to one-twelfth of the difference between the XOS 1 Hour and XTS price levels, which equates to one-twelfth of \$2.68/MWh = \$0.22/MWh. This approach is not based on a specific value assessment but simply reflects that if XOS 1 Month capacity is scheduled for a year, it has twelve opportunities to be displaced by or curtailed before XTS capacity.

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	1.74	1.87	3.61
Interconnection – POD	-	-	-
Operating Reserve	-	2.43	2.43
Voltage Control	-	-	-
Other System Support	-	-	-
<b>Total</b>	<b>1.74</b>	<b>4.29</b>	<b>6.03</b>

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 Rates

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	22.2	13.6	35.8	0.41	0.25	0.65
Other System	<u>143.7</u>	<u>88.5</u>	<u>232.1</u>	<u>2.63</u>	<u>1.62</u>	<u>4.25</u>
System Total	165.8	102.1	268.0	3.03	1.87	4.90

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.

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.

5 To assess the form and level of the PSC, the AESO reviewed the least cost estimates provided for dual-use sites in Table 4.10.1 of section 4.10 of its 2006 GTA, together with details of the estimates provided in Information Response COSC.AESO-003 in that proceeding. The PSC should continue to reflect transformation costs that would otherwise qualify for investment under the AESO's customer contribution policy, as approved by the EUB in Decision 2005-096. Such costs are reasonably reflected by the values provided for the "substation" component of costs in Table 4.10.1 of the 2006 GTA, which excludes costs relating to line, telecom, and protection components. The AESO considers that the costs should also not reflect multiple breakers which indicate "in and out" or "breaker and a half" configuration, where the breakers are on the high-voltage side of the transformers and should be owned by the TFO. The AESO has therefore excluded multiple-breaker projects from the analysis, based on the information provided in Information Response COSC.AESO-003. Analysis of "substation" component costs for the 13 remaining single-breaker least cost estimates provides a transformation cost function of:

20 Transformation Costs = \$1.542 million + (\$0.034 million/MW × DTS Capacity)

To determine the appropriate PSC level based on this cost function, it is compared to the point of delivery cost function already provided in section 4.3.4 of this Application:

25 Point of Delivery Costs = \$2.296 million  
+ (\$0.279 million/MW × first 17 MW of DTS Capacity)  
+ (\$0.154 million/MW × DTS Capacity above 17 MW)

30 These two cost functions can then be used to estimate the level of primary service credit for customer ownership of transformation. That credit should reflect:

- \$1.542 ÷ \$2.296 = 67.2% of the customer-related component of the POD charge, and
  - \$0.034 ÷ \$0.154 = 22.1% of the final demand-related component of the POD charge.
- Since the demand-related component of the transformation costs represents an average cost, and the final demand-related component of the POD costs also represents an average cost, it is only this final demand-related component which is relevant to this analysis.

The level of the PSC can then be calculated from the POD charge in the DTS rate:

- \$11,194/month × Substation Fraction × 67.2% = \$7,522/month × Substation Fraction, and
- \$753/MW × 22.1% = \$166/MW.

For its 2007 tariff, the AESO therefore proposes a PSC of:

45 PSC = (\$7,522.00/month × Substation Fraction) + (\$166.00/MW × Billing Capacity)

The AESO considers this form of credit to more closely align with the form of the proposed POD charge.

5 The AESO also 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.

10 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  
15 the maximum investment level be reduced when conventional transformation equipment is not provided by the TFO, whether through customer ownership of transformation or through unconventional or “virtual” interconnections.

20 The reduction to the maximum investment level should be determined on the same basis as the PSC itself is determined from the average POD charge: by applying the percentages determined above to the point of delivery costs function. That reduction is therefore calculated from the POD costs:

- \$2.296 million × Substation Fraction × 67.2% = \$1.543 million × Substation Fraction, and
- \$0.154 million/MW × 22.1% = \$0.034 million/MW.

25 Where the TFO does not provide conventional transformation as part of a customer’s interconnection, the maximum investment level should therefore be reduced by \$1.543 million × Substation Fraction and by \$0.034 million/MW of DTS Capacity. These changes have been incorporated into Article 9 of the terms and conditions of service in section 6 of  
30 this Application.

35 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.

40 This revised eligibility criterion is also reflected in the PSC rate schedule.

#### **4.X Rate Riders [Not Yet Complete]**

[Essentially similar to 2006 Application]



## SCHEDULES AND CALCULATIONS

No.	Description
<b>2007 Revenue Requirement</b>	
2.0	2007 Phase I Revenue Requirement Schedule
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**Alberta Electric System Operator  
AESO 2007 General Tariff Application**

Revenue Requirement  
Schedule 2.0 Draft  
September 18, 2006

**Schedule 2.0: 2007 Phase I Revenue Requirement Schedule (\$ millions)**

Line No.		<u>2007 Forecast</u>
	<b>WIRES</b>	
	TFO Wires-Related Costs	
1	AltaLink	193.7
2	ATCO Electric Ltd.	166.4
3	Isolated Generation	(7.9)
4	Subtotal ATCO Costs	<u>158.5</u>
5	Enmax Power Corporation	34.7
6	EPCOR Transmission Inc.	38.1
7	City of Lethbridge	4.4
8	TransAlta	3.7
9	Refund to the AESO	-
10	Subtotal TransAlta Costs	<u>3.7</u>
11	City of Red Deer	1.7
12	FortisAlberta Networks (Farm)	1.9
13	Subtotal TFO Wires-Related Costs	<u><b>436.7</b></u>
	Non-Wires Costs	
14	Invitation to Bid on Credits (IBOC)	1.7
15	Location Based Credit Standing Offer (LBC SO)	9.2
16	Subtotal IBOC/LBC SO Costs	<u>10.9</u>
17	<b>TOTAL WIRES COSTS</b>	<u><b>447.6</b></u>
	<b>ANCILLARY SERVICES</b>	
	Operating Reserves	
	Active	
18	Regulating	38.2
19	Spinning	46.3
20	Supplemental	31.8
21	Subtotal Active Reserves	<u>116.3</u>
	Standby	
22	Regulating	4.1
23	Spinning	5.4
24	Supplemental	2.9
25	Subtotal Standby Reserves	<u>12.4</u>
26	Trading fees & other related charges	
27	Subtotal Operating Reserves	<u>128.7</u>
	Other Ancillary Services	
28	Brazeau Fast Ramp (Previously GRAS)	0.6
29	Black Start	2.4
30	Transmission Must Run (TMR)	55.6
31	Under Frequency Mitigation	6.1
32	Subtotal Other Ancillary Services	<u>64.7</u>
	Poplar Hill/ILRAS	
33	Poplar Hill	1.9
34	Interruptible Load Remedial Action Scheme (ILRAS)	0.7
35	Generator Remedial Action Schemes (RAS)	1.0
36	Subtotal Poplar Hill/ILRAS	<u>3.6</u>
37	<b>TOTAL ANCILLARY SERVICES</b>	<u><b>197.0</b></u>
	<b>LOSSES</b>	
38	Pool Payment	194.1
39	Prior Year Losses Adjustments	
40	<b>TOTAL LOSSES COSTS</b>	<u><b>194.1</b></u>

**Alberta Electric System Operator  
AESO 2007 General Tariff Application**

Revenue Requirement  
Schedule 2.0 Draft  
September 18, 2006

**Schedule 2.0: 2007 Phase I Revenue Requirement Schedule (\$ millions)**

Line No.	<u>2007 Forecast</u>
<b>OTHER INDUSTRY COSTS</b>	
41 External Regulatory Costs	1.5
42 Western Electricity Coordination Council (WECC)	1.4
43 Share of EUB Overhead	1.8
44 TOTAL OTHER INDUSTRY COSTS	<u>4.7</u>
<b>GENERAL AND ADMINISTRATIVE COSTS</b>	
<b>Administrative Costs</b>	
45 Staff and Benefits	21.1
46 Consultants	2.3
47 Board Members Fees	0.4
48 Travel and Training	1.0
49 Legal	0.4
50 Audits/Reviews	0.3
51 Rent	1.6
52 Insurance	0.4
53 Other Administrative Costs	1.6
54 Telecomm and IT Maintenance	1.3
55 Interconnection Fees (offset)	0.0
56 Total Administrative Costs	<u>30.4</u>
<b>General Costs</b>	
57 Interest	0.5
58 Amortization and Depreciation	4.3
Taxes	-
59 Total General Costs	<u>4.8</u>
60 TOTAL GENERAL & ADMINISTRATIVE COSTS	<u>35.2</u>
61 Total G&A and Other Industry Costs	<u>39.9</u>
62 TOTAL REVENUE REQUIREMENT	<u>878.6</u>
<b>CAPITAL</b>	
63 Capitalized Salaries and Benefits	0.9
64 General Capital	3.2
65 System Coordination Centre	-
66 Total Capital	<u>4.1</u>

Note: Totals in this schedule, and subsequent schedules and tables, may be different due to rounding.

**2007 Rate Calculations**  
**Revenue Requirement Allocation to Demand and Supply Transmission Service**

Line No.	Description	A 2007 Forecast \$ 000 000	B		C		D		E	
			Allocator %	Amount \$ 000 000	Allocator %	Amount \$ 000 000	Allocator %	Amount \$ 000 000	Allocator %	Amount \$ 000 000
1	Wires									
2	Bulk System	\$ 186.6	100%	\$ 186.6			-	\$ -		
3	Local System	77.8	100%	77.8						
4	Point of Delivery	183.2	100%	183.2						
5	Total Wires	\$ 447.6	100%	\$ 447.6						
6	Ancillary Services									
7	Operating Reserves	\$ 128.7	100%	\$ 128.7						
8	Other Ancillary Services									
9	Brazeau Fast Ramp	0.6	100%	0.6						
10	Black Start	2.4	100%	2.4						
11	Transmission Must Run (TMR)	55.6	100%	55.6						
12	Under Frequency Mitigation	6.1	100%	6.1						
13	Poplar Hill	1.9	100%	1.9						
14	ILRAS	0.7	100%	0.7						
15	Generator Remedial Action Schemes	1.0	100%	1.0						
16	Total Ancillary Services	\$ 197.0	100%	\$ 197.0						
17	Losses	\$ 194.1		\$ -			100%	\$ 194.1		
18	Other Industry	\$ 4.7	100%	\$ 4.7						
19	General and Administrative	\$ 35.2	100%	\$ 35.2						
20	Total Revenue Requirement	\$ 878.6		\$ 684.5			22%	\$ 194.1		
21	Tariff Revenue Offsets			(34.8)						(7.4)
22	Regulated Generating Unit Connection Costs			-						21.4
23	Net DTS and STS Revenue Requirement			\$ 649.7				\$ 208.1		

Note: 2007 Forecast revenue requirement (Column A) from Section 2, Schedule 2.0

**Alberta Electric System Operator  
AESO 2007 General Tariff Application**

Rate Calculations  
Schedule 5.2 Draft  
September 18, 2006

**2007 Rate Calculations  
Tariff Revenue Offsets**

Line No.	Description	A	B		C	D		E
		2007 Forecast \$ 000 000	Allocator %	Amount \$ 000 000	Allocation to DTS Amount \$ 000 000	Allocator %	Amount \$ 000 000	Allocation to STS Amount \$ 000 000
1	DTS Tariff Revenue Offsets							
2	Power Factor Deficiency Revenue	\$ (0.2)	100%	\$ (0.2)		-	\$ -	
3	Demand Opportunity Service Revenue	(5.8)	100%	(5.8)		-	-	
4	Export and Merchant Service Revenue	(11.8)	100%	(11.8)		-	-	
5	UFLS Credits	2.1	100%	2.1		-	-	
6	Primary Service Credits	3.8	100%	3.8		-	-	
7	RGU Connection Costs	(21.4)	100%	(21.4)		-	-	
8	Fort Nelson Demand Service Revenue	(0.7)	100%	(0.7)		-	-	
9	Duplication Avoidance Adjustments	(0.8)	100%	(0.8)		-	-	
10	<b>Total DTS Offsets</b>	<b>\$ (34.8)</b>	<b>100%</b>	<b>\$ (34.8)</b>		<b>-</b>	<b>\$ -</b>	
11	STS Tariff Revenue Offsets							
12	Demand Opportunity Service Losses	\$ 0.8	-	\$ -		100%	\$ 0.8	
13	Export and Merchant Service Losses	(7.3)	-	-		100%	(7.3)	
14	Import Opportunity Service Losses	(0.8)	-	-		100%	(0.8)	
15	<b>Total STS Offsets</b>	<b>\$ (7.4)</b>	<b>-</b>	<b>\$ -</b>		<b>100%</b>	<b>\$ (7.4)</b>	
16	<b>Total Tariff Revenue Offsets</b>	<b>\$ (42.1)</b>	<b>83%</b>	<b>\$ (34.8)</b>		<b>17%</b>	<b>\$ (7.4)</b>	

**2007 Rate Calculations  
 Demand Transmission Service Costs Classified to Demand and Usage**

Line No.	Description	A	B	C	D	E	F	G	H	I
		DTS Amount [5.1 Col C] \$ 000 000	Non-Coincident Dem'd Allocator %	Amount \$ 000 000	Flat Usage Allocator %	Amount \$ 000 000	Varying Usage Allocator %	Amount \$ 000 000	Customer Allocator %	Amount \$ 000 000
1	Wires									
2	Bulk System	\$ 186.6	53.3%	\$ 99.5	46.7%	\$ 87.1	-	\$ -	-	-
3	Local System	77.8	82.5%	64.2	17.5%	13.6	-	-	-	-
4	Point of Delivery	183.2	69.8%	127.8	-	-	-	-	30.2%	55.4
5	<b>Total Wires</b>	<b>\$ 447.6</b>	<b>65.1%</b>	<b>\$ 291.5</b>	<b>22.5%</b>	<b>\$ 100.7</b>	<b>-</b>	<b>\$ -</b>	<b>12.4%</b>	<b>\$ 55.4</b>
6	Ancillary Services									
7	Operating Reserves	\$ 128.7	-	-	-	-	100.0%	\$ 128.7	-	-
8	Other Ancillary Services									
9	Brazeau Fast Ramp	0.6	-	-	-	-	100.0%	0.6	-	-
10	Black Start	2.4	-	-	-	-	100.0%	2.4	-	-
11	Transmission Must Run (TMR)	55.6	-	-	100.0%	55.6	-	-	-	-
12	Under Frequency Mitigation	6.1	100.0%	6.1	-	-	-	-	-	-
13	Poplar Hill	1.9	100.0%	1.9	-	-	-	-	-	-
14	ILRAS	0.7	61.9%	0.4	38.1%	0.3	-	-	-	-
15	Generator Remedial Action Schemes	1.0	-	-	-	-	100.0%	1.0	-	-
16	<b>Total Ancillary Services</b>	<b>\$ 197.0</b>	<b>4.3%</b>	<b>\$ 8.4</b>	<b>28.4%</b>	<b>\$ 55.9</b>	<b>67.4%</b>	<b>\$ 132.7</b>	<b>-</b>	<b>\$ -</b>
17	Losses	-	-	-	-	-	-	-	-	-
18	Other Industry	\$ 4.7	65.1%	\$ 3.1	22.5%	\$ 1.1	-	\$ -	12.4%	\$ 0.6
19	General and Administrative	\$ 35.2	65.1%	\$ 22.9	22.5%	\$ 7.9	-	\$ -	12.4%	\$ 4.4
20	<b>Total Revenue Requirement</b>	<b>\$ 684.5</b>	<b>47.6%</b>	<b>\$ 326.0</b>	<b>24.2%</b>	<b>\$ 165.5</b>	<b>19.4%</b>	<b>\$ 132.7</b>	<b>8.8%</b>	<b>\$ 60.3</b>
21	DTS Tariff Revenue Offsets	(34.8)	65.1%	(22.6)	22.5%	(7.8)	-	-	12.4%	\$ (4.3)
22	<b>Net DTS Revenue Requirement</b>	<b>\$ 649.7</b>	<b>46.7%</b>	<b>\$ 303.3</b>	<b>24.3%</b>	<b>\$ 157.7</b>	<b>20.4%</b>	<b>\$ 132.7</b>	<b>8.6%</b>	<b>\$ 56.0</b>

**2007 Rate Calculations  
 Demand Transmission Service Cost Recovery**

Line No.	Description	Sch 5.3 Reference	A	B	C	D	E
			Non-Coincident Demand Amount [5.3 Col E] \$ 000 000	Flat Usage Amount [5.3 Col G] \$ 000 000	Varying Usage Amount [5.3 Col H] \$ 000 000	Customer Amount [5.3 Col I] \$ 000 000	Total Amount [A + B + C + D] \$ 000 000
1	DTS Interconnection Charge						
2	Wires						
3	Bulk System	Line 3	\$ 99.5	\$ 87.1	-	-	\$ 186.6
4	Local System	Line 3	64.2	13.6	-	-	77.8
5	Point of Delivery	Line 4	127.8	-	-	55.4	183.2
6	Non-Wires						
7	ILRAS	Line 14	0.4	0.3	-	-	0.7
8	Other Industry	Line 18	3.1	1.1	-	0.6	4.7
9	General and Administrative	Line 19	22.9	7.9	-	4.4	35.2
10	DTS Tariff Revenue Offsets	Line 21	(22.6)	(7.8)	-	(4.3)	(34.8)
11	DTS Interconnection Charge		\$ 295.3	\$ 102.1	-	\$ 56.0	\$ 453.4
12	DTS Operating Reserve Charge						
13	Operating Reserves	Line 7	-	-	\$ 128.7	-	\$ 128.7
14	Brazeau Fast Ramp	Line 9	-	-	0.6	-	0.6
15	Black Start	Line 10	-	-	2.4	-	2.4
16	Generator Remedial Action Schemes	Line 15	-	-	1.0	-	1.0
17	DTS Operating Reserve Charge		-	-	\$ 132.7	-	\$ 132.7
18	Voltage Control (TMR) Charge	Line 11	-	\$ 55.6	-	-	\$ 55.6
19	DTS Other System Support Services Charge						
20	Under Frequency Mitigation	Line 12	\$ 6.1	-	-	-	\$ 6.1
21	Poplar Hill	Line 13	1.9	-	-	-	1.9
22	DTS OSS Services Charge		\$ 8.0	-	-	-	\$ 8.0
23	Total DTS Tariff		\$ 303.3	\$ 157.7	\$ 132.7	\$ 56.0	\$ 649.7



**2007 Rate Calculations  
 Supply Transmission Service Costs Classified to Demand and Usage**

Line No.	Description	A	B	C	D	E	F	G	H	I
		STS Amount [5.1 Col E] \$ 000 000	Non-Coincident Dem'd		Flat Usage		Varying Usage		Customer	
			Allocator %	Amount \$ 000 000	Allocator %	Amount \$ 000 000	Allocator %	Amount \$ 000 000	Allocator %	Amount \$ 000 000
1	Wires									
2	System	-	-	-	-	-	-	-	-	-
3	Point of Delivery	-	-	-	-	-	-	-	-	-
4	<b>Total Wires</b>	-	-	-	-	-	-	-	-	-
5	<b>Ancillary Services</b>									
6	Operating Reserves	-	-	-	-	-	-	-	-	-
7	Other Ancillary Services									
8	Generator Remedial Action Schemes	-	-	-	-	-	-	-	-	-
9	Black Start	-	-	-	-	-	-	-	-	-
10	Transmission Must Run (TMR)	-	-	-	-	-	-	-	-	-
11	Under Frequency Mitigation	-	-	-	-	-	-	-	-	-
12	Poplar Hill	-	-	-	-	-	-	-	-	-
13	ILRAS	-	-	-	-	-	-	-	-	-
14	<b>Total Ancillary Services</b>	-	-	-	-	-	-	-	-	-
15	Losses	194.1	-	-	-	-	100.0%	194.1	-	-
16	Other Industry	-	-	-	-	-	-	-	-	-
17	General and Administrative	-	-	-	-	-	-	-	-	-
18	<b>Total Revenue Requirement</b>	<b>\$ 194.1</b>	-	-	-	-	<b>100.0%</b>	<b>\$ 194.1</b>	-	-
19	STS Tariff Revenue Offsets	(7.4)	-	-	-	-	100.0%	(7.4)	-	-
20	RGU Connection Costs	21.4	100.0%	21.4	-	-	-	-	-	-
21	<b>Net DTS Revenue Requirement</b>	<b>\$ 208.1</b>	<b>10.3%</b>	<b>\$ 21.4</b>	-	-	<b>89.7%</b>	<b>\$ 186.7</b>	-	-

**2007 Rate Calculations**  
**Supply Transmission Service Rate Calculation**

Line No.	Description	Sch 5.6 Reference	Costs, \$ 000 000			Billing Determinant		Rate			
			A	B	C	D	E	F	G	H	I
			Losses	Other	Total	Quantity	Unit	Losses	Other	Total	Unit
1	STS Losses Charge (Notes 1 and 2)										
2	Losses Charge	Lines 16, 20	\$ 194.1	(7.4)	\$ 186.7	58,968.9	GWh	5.02%	(0.19%)	4.83%	× Pool Price
3	RGU Connection Costs (Note 3)										
4	RGU Connection Costs	Line 21	-	21.4	21.4	70,395.6	MW-months	\$ -	\$ 304.00	\$ 304.00	/MW
5	Total STS Cost Recovery		\$ 194.1	\$ 14.0	\$ 208.1						

- Notes: 1. The 2007 forecast pool price is \$65.61/MWh  
2. Location-specific loss factors are determined by the AESO for each STS customer, and the value calculated is an illustrative average only  
3. RGU (Regulated Generating Unit) Connection Costs charge is applicable only to regulated generating units as listed in Appendix A of the AESO Rate Schedules



**Alberta Electric System Operator  
AESO 2007 General Tariff Application**

Rate Calculations  
Schedule 5.9 Draft  
September 18, 2006

**2007 Rate Calculations  
2007 Billing Determinants**

Line No.	Determinant	DTS Customers		STS Customers	
		Quantity	Unit	Quantity	Unit
1	DTS Billing Capacity (Total)	118,929.4	MW-months	—	
2	DTS Billing Capacity Less Than or Equal to 17 MW	65,357.8	MW-months	—	
3	DTS Billing Capacity in Excess of 17 MW	53,571.6	MW-months	—	
4	DTS Highest Monthly Metered Demands	101,353.4	MW-months	—	
5	Metered Energy (All Hours)	54,682.5	GWh	58,968.9	GWh
6	DTS Customers (Equivalent) (Note 1)	5,004.4	customer-months	—	
7	Pool Price (Note 2)	\$65.61	/MWh	\$65.61	/MWh
8	RGU Maximum Continuous Rating (MCR)	—		70,395.6	MW-months

- Note:
1. DTS Customers (Equivalent) is the sum of Substation Fractions for all DTS customers
  2. Pool Price is the average hourly pool price weighted by DTS usage volumes

**Alberta Electric System Operator  
AESO 2007 General Tariff Application**

Rate Calculations  
Schedule 5.10 Draft  
September 18, 2006

**2007 Rate Calculations  
Rate Change Impact Compared to 2006 Rates**

Line No.	Description	Approved 2006 Rates			Proposed 2007 Rates			Increase (Decrease)	
		2006 Rate	2007 Determinant	Amount \$ 000 000	2007 Rate	2007 Determinant	Amount \$ 000 000	Amount \$ 000 000	Percent %
1	DTS Tariff								
2	Interconnection Charge								
3	Bulk System Charge — Demand	\$ 1,233.00	84,839.3	\$ 104.6	\$ 1,395.00	118,929.4	\$ 165.9	\$ (4.5)	(2.6%)
4	Local System Charge — Demand	\$ 553.00	118,929.4	65.8					
5	Bulk System Charge — Usage	\$ 1.41	54,682.5	77.1	\$ 1.87	54,682.5	102.3	10.9	12.0%
6	Local System Charge — Usage	\$ 0.26	54,682.5	14.2					
7	POD Charge — Demand ≤ 17 MW	\$ 707.00	118,929.4	84.1	\$ 1,364.00	65,357.8	89.1	45.4	54.0%
8	POD Charge — Demand > 17 MW				\$ 753.00	53,571.6	40.3		
9	POD Charge — Usage	\$ 0.08	54,682.5	4.4					
10	POD Charge — Customer	\$21,899.00	4,693.4	102.8	\$ 11,194.00	5,004.4	56.0	(54.0)	(49.1%)
11	POD Charge — Demand ≤ 5 MW	\$ 4,380.00	660.7	2.9					
12	Total Interconnection Charge	—	—	455.8	—	—	453.7	(2.2)	(0.5%)
13	Operating Reserve Charge — % of PP	3.87%	54,682.5	138.8	3.70%	54,682.5	132.7	(6.1)	(4.4%)
14	Voltage Control Charge — Usage	\$ 0.98	54,682.5	53.6	\$ 1.02	54,682.5	55.8	2.2	4.1%
15	OSS Service Charge — Demand	\$ 76.00	101,353.4	7.7	\$ 79.00	101,353.4	8.0	0.3	3.9%
16	Total DTS Tariff			\$ 656.0			\$ 650.2	\$ (5.8)	(0.9%)
17	STS Tariff								
18	Losses Charge — % of PP	5.06%	58,968.9	195.8	4.83%	58,968.9	\$ 186.9	\$ (8.9)	(4.5%)
19	RGU Connection Costs — Demand	\$ 326.00	70,395.6	22.9	\$ 304.00	70,395.6	21.4	(1.5)	(6.7%)
20	Total STS Tariff			\$ 218.7			\$ 208.3	\$ (10.4)	(4.8%)
21	Total DTS and STS Tariffs			\$ 874.7			\$ 858.5	\$ (16.2)	(1.9%)

- Notes: 1. The 2007 AESO forecast of pool price is \$65.61/MWh  
2. 2006 rates (Column A) are as approved in EUB Order 2005-464 dated December 20, 2005, on the AESO's 2005-2006 General Tariff Application Second Refiling  
3. Amounts determined under Approved 2006 Rates are based on the 2006 pool price of \$65.61/MWh.

**2007 Fort Nelson Rate Calculations  
Fort Nelson Transmission Service Rate Calculation**

Line No.	Description	Sch 5.5 Reference	Rate		Billing Determinant		Revenue \$ 000
			Amount	Unit	Quantity	Unit	
1	FTS System Charge						
2	Bulk System Demand Component	Line 2	\$ 848.00	/MW	268.1	MW-months	\$ 227.3
3	Local System Demand Component	Note 1	\$ 1,511.00	/MW	268.1	MW-months	405.1
4	Non-Coincident Demand Charge	[L2 + L3]	\$ 2,359.00	/MW	268.1	MW-months	632.4
5	Bulk System Usage Component	Line 3	\$ 1.62	/MWh	9.9	GWh	16.0
6	Local System Usage Component	Note 1	\$ 0.70	/MWh	9.9	GWh	6.9
7	Usage Charge	[L5 + L6]	\$ 2.32	/MWh	9.9	GWh	22.9
8	FTS Operating Reserve Charge						
9	Varying Usage Charge	Line 11	3.70%	× Pool Price (Note 2)	9.9	GWh	24.0
10	FTS Voltage Control (TMR) Charge						
11	Flat Usage Charge	Line 15	\$ 1.02	/MWh	9.9	GWh	10.1
12	FTS Other System Support Services Charge						
13	Non-Coincident Demand Charge	Line 17	\$ 79.00	/MW	268.1	MW-months	21.2
14	Total FTS Cost Recovery						\$ 710.6

Notes: 1. Direction 7 of Decision 2005-096 established the Fort Nelson local system charge to be "the greater of the postage stamp rate for local wires costs or the actual cost of the AE line providing service to Fort Nelson." Based on the Local System components of the DTS System Charge: from Schedule 5.5:

DTS Local System Wires Demand Charge	\$ 540.00 /MW	×	268.1 MW-months	=	\$ 144,758
DTS Local System Wires Usage Charge	\$ 0.25 /MWh	×	9.9 GWh	=	2,475
Total postage stamp rate for local wires costs					\$ 147,233

The actual cost of the AE line providing service to Fort Nelson, as provided in Information Response BCH.AESO-005, is \$410,139 per year, and therefore determines the FTS Local System Charge (in conjunction with non-wires costs from Schedule 5.5):

	Wires	Non-Wires	Total	Units
FTS Local System Demand Charge	\$1,504.00	\$7.00	\$1,511.00	/MW
FTS Local System Usage Charge	\$0.70	\$0.00	\$0.70	/MWh

2. The 2007 forecast pool price is \$65.61/MWh

**Alberta Electric System Operator  
AESO 2007 General Tariff Application**

Rate Calculations  
Schedule 5.12 Draft  
September 18, 2006

**2007 Fort Nelson Rate Calculations  
2007 Billing Determinants**

Line No.	Determinant	FTS Customer	
		A Quantity	B Unit
1	FTS Billing Capacity	268.1	MW-months
2	Metered Energy (All Hours)	9.9	GWh
3	Pool Price (Note)	\$65.61	/MWh

Note: Pool Price is the average hourly pool price weighted by DTS usage volumes



## 2007 RATES

Code	Description
<b>Rate Schedules</b>	
DTS	Demand Transmission Service
FDS	Fort Nelson Demand Transmission Service
DOS 7 Minutes	Demand Opportunity Service (7 Minutes)
DOS Term	Demand Opportunity Service (Term)
XTS	Export Transmission Service
XOS 1 Hour	Export Opportunity Service (1 Hour)
XOS 1 Month	Export Opportunity Service (1 Month)
MTS	Merchant Transmission Service
MOS 1 Hour	Merchant Opportunity Service (1 Hour)
MOS 1 Month	Merchant Opportunity Service (1 Month)
UFLS	Demand Under-Frequency Load Shedding Credits
PSC	Primary Service Credit
STS	Supply Transmission Service
IOS	Import Opportunity Service
<b>Rate Riders</b>	
A1	Dow Chemical Transmission Duplication Avoidance Adjustment *
A2	Nova Chemicals Transmission Duplication Avoidance Adjustment *
A3	Shell Scotford Transmission Duplication Avoidance Adjustment *
A4	Imperial Oil Resources Limited Transmission Duplication Avoidance Adjustment *
B	Working Capital Deficiency/Surplus Rider *
C	Deferral Account Adjustment Rider *
E	Losses Calibration Factor Rider *
F	Balancing Pool Consumer Allocation Rider *
<b>Rate Appendix</b>	
Maximum Continuous Rating for Regulated Generation Units Under Rate STS *	

\* Rate is not included because it is expected to be materially unchanged from the 2006 rate

**DTS Demand Transmission Service Page 1 of 2**

Applicable to: Demand Customers.

Rate: Charges for DTS in any one Billing Period shall be the sum of the Interconnection Charge, the Operating Reserve Charge, the Voltage Control Charge, and the Other System Support Services Charge, where:

The **Interconnection Charge** equals:

- (1) a **System Charge** of
- **\$1,395.00/MW/month** of Billing Capacity in the Billing Period, plus
  - **\$1.87/MWh** of Metered Energy during the Billing Period;

Plus

- (2) a **Point of Delivery Charge** of

- (a) **\$1,364.00/MW/month** for the first 17 MW of Billing Capacity in the Billing Period, plus
- (b) **\$753.00/MW/month** for all Billing Capacity over 17 MW in the Billing Period, plus
- (b) **\$11,194.00/month** multiplied by the Substation Fraction in the Billing Period.

Billing Capacity shall be the highest of:

- (i) the highest fifteen (15) minute Metered Demand in the Billing Period;
- (ii) 90% of the highest Metered Demand in the 24-month period including and ending with the Billing Period; or
- (iii) 90% of the Contract Capacity,

The **Operating Reserve Charge** equals:

- Metered Energy in each hour  $\times$  **3.70%**  $\times$  **Pool Price**.

The **Voltage Control Charge** equals:

- **\$1.02/MWh** of Metered Energy during the Billing Period.

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,

**DTS**                      **Demand Transmission Service**                      Page 2 of 2

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.

- Terms:
- (a) References to Metered Energy in this Rate Schedule shall mean the amount of Metered Energy attributable to service under this Rate Schedule, which shall be determined in accordance with Article 10.4 of the Terms and Conditions.
  - (b) The DTS rate is separately applicable at each POD.
  - (c) When invoked by the AESO, Rate Riders B and C apply to customers under this Rate Schedule.
  - (d) When invoked by the AESO, Rate Rider F applies to customers under this Rate Schedule with the exception of the City of Medicine Hat.
  - (e) The Terms and Conditions form part of this Rate Schedule.

**FTS Fort Nelson Demand Transmission Service** Page 1 of 2

Applicable to: BC Hydro for demand service to Fort Nelson, British Columbia.

Rate: Charges for FTS in any one Billing Period shall be the sum of the Interconnection Charge, the Operating Reserve Charge, the Voltage Control Charge, and the Other System Support Services Charge, where:

The **Interconnection Charge** equals:

- **\$2,359.00/MW/month** of Billing Capacity in the Billing Period, plus
- **\$2.32/MWh** of Metered Energy during the Billing Period;

Billing Capacity shall be the highest of:

- (i) the highest fifteen (15) minute Metered Demand in the Billing Period;
- (ii) 90% of the highest Metered Demand in the 24-month period including and ending with the Billing Period; or
- (iii) 90% of the Contract Capacity,

The **Operating Reserve Charge** equals:

- Metered Energy in each hour  $\times$  **3.70%**  $\times$  **Pool Price**.

The **Voltage Control Charge** equals:

- **\$1.02/MWh** of Metered Energy during the Billing Period.

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.

- Terms:
- (a) References to Metered Energy in this Rate Schedule shall mean the amount of Metered Energy attributable to service under this Rate Schedule, which shall be determined in accordance with Article 10.4 of the Terms and Conditions.
  - (b) The FTS rate is separately applicable at each POD.
  - (c) When invoked by the AESO, Rate Riders B and C apply to customers under this Rate Schedule.



**FTS**

**Fort Nelson Demand Transmission Service**

Page 2 of 2

(d) The Terms and Conditions form part of this Rate Schedule.



**DOS 7 Minutes Demand Opportunity Service (7 Minutes)**

Page 1 of 2

Applicable to: Qualified Opportunity Service Customers who are recallable within seven (7) minutes.

Available: For quantities of Metered Energy taken within the Opportunity Capacity for the relevant System Access Service Agreement for Demand Opportunity Service, and when sufficient transmission capacity exists to accommodate such quantity. This service will be available a minimum of one (1) hour for Customers deemed eligible in the pre-qualification process, following the execution of a System Access Service Agreement.

Rate: The charges for service per Billing Period shall be as follows:

(1) The greater of (a) and (b) below:

- (a) (i) **\$5.81/MWh** of Metered Energy during the Billing Period; plus
- (ii) Incremental Losses Charge, calculated as the sum over each transaction hour of the Billing Period of the following:
  - Metered Energy in hour  $\times$  location specific loss factor  $\times$  Pool Price for the hour,  
where "location specific loss factor" is defined in the ISO Rules and determined in accordance with ISO Rule 9.2.
- (b) A minimum charge equal to:
  - Opportunity Capacity under this Rate Schedule  $\times$  number of hours in total transactions in the Billing Period  $\times$  75%  $\times$  **\$5.81/MWh**.

Plus

(2) Transaction Fee: **\$500.00** per Billing Period.

Terms: (a) The rate is separately applicable at each POD.

- (b) A Customer's pre-qualified eligibility for Demand Opportunity Service will be available for a maximum of one (1) year. The term for a System Access Service Agreement for Demand Opportunity Service will be:
  - (i) no less than a continuous eight hours from 0:00 hr midnight to 24:00 hr, or such other minimum term as the AESO may, at its discretion set; and
  - (ii) no greater than one (1) calendar month.

**DOS 7 Minutes Demand Opportunity Service (7 Minutes)**

Page 2 of 2

- (c) To the extent practicable, service for Opportunity Service Customers taking service under this Rate Schedule shall be recallable in advance of service for Non-Recallable Customers in an Emergency.
- (d) In the event that a Customer's service is recalled, the Customer shall be required to curtail load by the amount directed by the System Controller, which can be an amount up to the Opportunity Capacity, subject to no requirement on the Customer to curtail to below the DTS Contract Capacity. Curtailment of such amount shall be achieved within seven (7) minutes of receiving a directive from the System Controller.
- (e) References to Metered Energy in this Rate Schedule shall mean the amount of Metered Energy attributable to service under this Rate Schedule, which shall be determined in accordance with Article 10.4 of the Terms and Conditions.
- (f) When invoked by the AESO, Rate Riders E and F apply to customers under this rate schedule.
- (g) The Terms and Conditions form part of this Rate Schedule.



**DOS Term**                      **Demand Opportunity Service (Term)**                      Page 1 of 2

Applicable to:                      Qualified Opportunity Service Customers who are recallable within seven (7) minutes.

Available:                      For quantities of Metered Energy taken within the Opportunity Capacity for the relevant System Access Service Agreement for Demand Opportunity Service, and when sufficient transmission capacity exists to accommodate such quantity. This service will be available a minimum of one (1) hour for Customers deemed eligible in the pre-qualification process, following the execution of a System Access Service Agreement.

Rate:                      The charges for service per Billing Period shall be as follows:

- (1) The greater of (a) and (b) below:
  - (a) (i) **\$21.65/MWh** of Metered Energy during the Billing Period; plus
  - (ii) Incremental Losses Charge, calculated as the sum over each transaction hour of the Billing Period of the following:
    - Metered Energy in hour x location specific loss factor x Pool Price for the hour,  
where “location specific loss factor” is defined in the ISO Rules and determined in accordance with ISO Rule 9.2.
  - (b) A minimum charge equal to:
    - Opportunity Capacity under this Rate Schedule x number of hours in total transactions in the Billing Period x 75% x **\$21.65/MWh.**

Plus

(2) Transaction Fee: **\$500.00** per Billing Period.

- Terms:
- (a) The rate is separately applicable at each POD.
  - (b) A Customer’s pre-qualified eligibility for Demand Opportunity Service will be available for a maximum of one (1) year. The term for a System Access Service Agreement for Demand Opportunity Service will be:
    - (i) no less than a continuous eight hours from 0:00 hr midnight to 24:00 hr, or such other minimum term as the AESO may, at its discretion set; and
    - (ii) no greater than one (1) calendar month.

**DOS Term**

**Demand Opportunity Service (Term)**

Page 2 of 2

- (c) To the extent practicable, service for Opportunity Service Customers taking service under this Rate Schedule shall be recallable in advance of service for Non-Recallable Customers in an Emergency.
- (d) In the event that a Customer's service is recalled, the Customer shall be required to curtail load by the amount directed by the System Controller, which can be an amount up to the Opportunity Capacity, subject to no requirement on the Customer to curtail to below the DTS Contract Capacity. Curtailment of such amount shall be achieved within seven (7) minutes of receiving a directive from the System Controller.
- (e) References to Metered Energy in this Rate Schedule shall mean the amount of Metered Energy attributable to service under this Rate Schedule, which shall be determined in accordance with Article 10.4 of the Terms and Conditions.
- (f) When invoked by the AESO, Rate Riders E and F apply to customers under this rate schedule.
- (g) The Terms and Conditions form part of this Rate Schedule.

**XTS**                      **Export Transmission Service**                      Page 1 of 2

Applicable to:        Customers exporting electric energy from the AIES over the Alberta-British Columbia or Alberta-Saskatchewan inter-ties.

Available:            When sufficient transmission capacity exists to accommodate the capacity scheduled for service. This service shall be available a minimum of twenty-four (24) hours following execution of a System Access Service Agreement for Export Transmission Service.

Rate:                    Charges for XTS in any one Billing Period shall be the sum of the Interconnection Charge, the Operating Reserve Charge, the Voltage Control Charge, and the Other System Support Services Charge, where:

The **Interconnection Charge** equals the greater of (a) and (b) below:

- (a) (i) **\$4.90/MWh** of Energy Transfer during the Billing Period; plus
- (ii) Incremental Losses Charge, calculated as the sum over all transaction hours in the Billing Period of the following:
  - Energy Transfer in hour × location specific loss factor × Pool Price for the hour,  
where “location specific loss factor” is defined in the ISO Rules and determined in accordance with ISO Rule 9.2.
- (b) A minimum charge calculated as the sum over all transactions in the Billing Period of the following (where capacity scheduled is the hour-ahead scheduled amount for the transaction):
  - 90% × capacity scheduled for Customer for the transaction × hours in the transaction × (**\$4.90/MWh** + Incremental Losses Charge / Energy Transfer in the Billing Period).

The **Operating Reserve Charge** equals:

- Energy Transfer in each hour × **3.70%** × **Pool Price**.

The **Voltage Control Charge** equals:

- **\$1.02/MWh** of Energy Transfer during the Billing Period.

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

- **\$0.15/MWh** of Energy Transfer during the Billing Period.

Terms:                (a) Rate XTS is separately applicable at each Point of Exchange.

                          (b) The minimum term for Rate XTS is one (1) calendar year.



**XTS**

**Export Transmission Service**

Page 2 of 2

- (c) When invoked by the AESO, Rate Riders B, C, and E apply to Customers under this Rate Schedule.
- (d) The Terms and Conditions form part of this Rate Schedule.



**XOS 1 Hour      Export Opportunity Service (1 Hour)      Page 1 of 2**

Applicable to: Customers exporting electric energy from the AIES over the Alberta-British Columbia or Alberta-Saskatchewan inter-ties.

Available: When sufficient transmission capacity exists to accommodate the capacity scheduled for service. This service shall be available a minimum of twenty-four (24) hours following execution of a System Access Service Agreement for Export Opportunity Service.

Rate: The charges for service per Billing Period shall be as follows:

(1) The greater of (a) and (b) below:

- (a) (i) **\$5.81/MWh** of Energy Transfer during the Billing Period; plus
- (ii) Incremental Losses Charge, calculated as the sum over all transaction hours in the Billing Period of the following:
  - Energy Transfer in hour  $\times$  location specific loss factor  $\times$  Pool Price for the hour,where "location specific loss factor" is defined in the ISO Rules and determined in accordance with ISO Rule 9.2.

- (b) A minimum charge calculated as the sum over all transactions in the Billing Period of the following (where capacity schedule is the hour-ahead scheduled amount for the transaction):
  - $75\% \times$  capacity scheduled for Customer for the transaction  $\times$  hours in the transaction  $\times$  (**\$5.81/MWh** + Incremental Losses Charge / Energy Transfer in the Billing Period).

Plus

- (2) An Operating Reserve charge or other System Support Service charge when, in the opinion of the AESO, the transaction requires the procurement of incremental System Support Services and/or Operating Reserve.

Plus

- (3) Transaction Fee: **\$500.00** per Billing Period.

Terms: (a) System Access Service provided pursuant to this Rate Schedule is recallable on one (1) hour's notice. To the extent practical, service for Export Opportunity Service Customers taking service under this Rate Schedule shall be recallable in advance of service provided under Rate XOS 1 Month and Rate XTS in an Emergency.



**XOS 1 Hour**

**Export Opportunity Service (1 Hour)**

Page 2 of 2

- (b) Rate XOS 1 Hour is separately applicable at each Point of Exchange.
- (c) The minimum term for Rate XOS 1 Hour is one (1) hour. The maximum term is one (1) calendar month.
- (d) When invoked by the AESO, Rate Rider E applies to customers under this rate schedule.
- (e) The Terms and Conditions form part of this Rate Schedule.



**XOS 1 Hour      Export Opportunity Service (1 Month)** Page 1 of 2

Applicable to: Customers exporting electric energy from the AIES over the Alberta-British Columbia or Alberta-Saskatchewan inter-ties.

Available: When sufficient transmission capacity exists to accommodate the capacity scheduled for service. This service shall be available a minimum of twenty-four (24) hours following execution of a System Access Service Agreement for Export Opportunity Service.

Rate: The charges for service per Billing Period shall be as follows:

(1) The greater of (a) and (b) below:

- (a) (i) **\$6.03/MWh** of Energy Transfer during the Billing Period; plus
- (ii) Incremental Losses Charge, calculated as the sum over all transaction hours in the Billing Period of the following:
  - Energy Transfer in hour x location specific loss factor x Pool Price for the hour,where “location specific loss factor” is defined in the ISO Rules and determined in accordance with ISO Rule 9.2.

- (b) A minimum charge calculated as the sum over all transactions in the Billing Period of the following (where capacity schedule is the hour-ahead scheduled amount for the transaction):
  - 75% x capacity scheduled for Customer for the transaction x hours in the transaction x (**\$6.03/MWh** + Incremental Losses Charge / Energy Transfer in the Billing Period).

Plus

- (2) An Operating Reserve charge or other System Support Service charge when, in the opinion of the AESO, the transaction requires the procurement of incremental System Support Services and/or Operating Reserve.

Plus

- (3) Transaction Fee: **\$500.00** per Billing Period.

Terms: (a) System Access Service provided pursuant to this Rate Schedule is recallable on one (1) hour's notice. To the extent practical, service for Export Opportunity Service Customers taking service under this Rate Schedule shall be recallable in advance of service provided under Rate XTS in an Emergency.



**XOS 1 Hour**

**Export Opportunity Service (1 Month)**

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- (b) Rate XOS 1 Month is separately applicable at each Point of Exchange.
- (c) The minimum term for Rate XOS 1 Month is one (1) calendar month. The maximum term is one (1) calendar year.
- (d) When invoked by the AESO, Rate Rider E applies to customers under this rate schedule.
- (e) The Terms and Conditions form part of this Rate Schedule.

**MTS Merchant Transmission Service** Page 1 of 2

**Applicable to:** Customers exporting electric energy from the AIES over an inter-tie other than the Alberta-British Columbia and Alberta-Saskatchewan inter-ties.

**Available:** When sufficient transmission capacity exists to accommodate the capacity scheduled for service. This service shall be available a minimum of twenty-four (24) hours following execution of a System Access Service Agreement for Export Transmission Service.

**Rate:** Charges for XTS in any one Billing Period shall be the sum of the Interconnection Charge, the Operating Reserve Charge, the Voltage Control Charge, and the Other System Support Services Charge, where:

The **Interconnection Charge** equals the greater of (a) and (b) below:

- (a) (i) **\$4.25/MWh** of Energy Transfer during the Billing Period; plus
- (ii) Incremental Losses Charge, calculated as the sum over all transaction hours in the Billing Period of the following:
  - Energy Transfer in hour  $\times$  location specific loss factor  $\times$  Pool Price for the hour, where “location specific loss factor” is defined in the ISO Rules and determined in accordance with ISO Rule 9.2.
- (b) A minimum charge calculated as the sum over all transactions in the Billing Period of the following (where capacity scheduled is the hour-ahead scheduled amount for the transaction):
  - $90\% \times$  capacity scheduled for Customer for the transaction  $\times$  hours in the transaction  $\times$  (**\$4.25/MWh** + Incremental Losses Charge / Energy Transfer in the Billing Period).

The **Operating Reserve Charge** equals:

- Energy Transfer in each hour  $\times$  **3.70%**  $\times$  **Pool Price**.

The **Voltage Control Charge** equals:

- **\$1.02/MWh** of Energy Transfer during the Billing Period.

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

- **\$0.15/MWh** of Energy Transfer during the Billing Period.

**Terms:** (a) Rate MTS is separately applicable at each Point of Exchange.

(b) The minimum term for Rate MTS is one (1) calendar year.



**MTS**

**Merchant Transmission Service**

Page 2 of 2

- (c) When invoked by the AESO, Rate Riders B, C, and E apply to Customers under this Rate Schedule.
- (d) The Terms and Conditions form part of this Rate Schedule.



**MOS 1 Hour Merchant Opportunity Service (1 Hour)** Page 1 of 2

Applicable to: Customers exporting electric energy from the AIES over an inter-tie other than the Alberta-British Columbia and Alberta-Saskatchewan inter-ties.

Available: When sufficient transmission capacity exists to accommodate the capacity scheduled for service. This service shall be available a minimum of twenty-four (24) hours following execution of a System Access Service Agreement for Export Opportunity Service.

Rate: The charges for service per Billing Period shall be as follows:

(1) The greater of (a) and (b) below:

- (a) (i) **\$5.36/MWh** of Energy Transfer during the Billing Period; plus
- (ii) Incremental Losses Charge, calculated as the sum over all transaction hours in the Billing Period of the following:

- Energy Transfer in hour  $\times$  location specific loss factor  $\times$  Pool Price for the hour,

where "location specific loss factor" is defined in the ISO Rules and determined in accordance with ISO Rule 9.2.

- (b) A minimum charge calculated as the sum over all transactions in the Billing Period of the following (where capacity schedule is the hour-ahead scheduled amount for the transaction):

- $75\% \times$  capacity scheduled for Customer for the transaction  $\times$  hours in the transaction  $\times$  (**\$5.36/MWh** + Incremental Losses Charge / Energy Transfer in the Billing Period).

Plus

- (2) An Operating Reserve charge or other System Support Service charge when, in the opinion of the AESO, the transaction requires the procurement of incremental System Support Services and/or Operating Reserve.

Plus

- (3) Transaction Fee: **\$500.00** per Billing Period.

Terms: (a) System Access Service provided pursuant to this Rate Schedule is recallable on one (1) hour's notice. To the extent practical, service for Merchant Opportunity Service Customers taking service under this Rate Schedule shall be recallable in advance of service provided under Rate MOS 1 Month and Rate MTS in an Emergency.



**MOS 1 Hour**

**Merchant Opportunity Service (1 Hour)**

Page 2 of 2

- (b) Rate MOS 1 Hour is separately applicable at each Point of Exchange.
- (c) The minimum term for Rate MOS 1 Hour is one (1) hour. The maximum term is one (1) calendar month.
- (d) When invoked by the AESO, Rate Rider E applies to customers under this rate schedule.
- (e) The Terms and Conditions form part of this Rate Schedule.



**MOS 1 Hour Merchant Opportunity Service (1 Month)** Page 1 of 2

Applicable to: Customers exporting electric energy from the AIES over an inter-tie other than the Alberta-British Columbia and Alberta-Saskatchewan inter-ties.

Available: When sufficient transmission capacity exists to accommodate the capacity scheduled for service. This service shall be available a minimum of twenty-four (24) hours following execution of a System Access Service Agreement for Export Opportunity Service.

Rate: The charges for service per Billing Period shall be as follows:

(1) The greater of (a) and (b) below:

- (a) (i) **\$5.55/MWh** of Energy Transfer during the Billing Period; plus
- (ii) Incremental Losses Charge, calculated as the sum over all transaction hours in the Billing Period of the following:
  - Energy Transfer in hour x location specific loss factor x Pool Price for the hour,where “location specific loss factor” is defined in the ISO Rules and determined in accordance with ISO Rule 9.2.

- (b) A minimum charge calculated as the sum over all transactions in the Billing Period of the following (where capacity schedule is the hour-ahead scheduled amount for the transaction):
  - 75% x capacity scheduled for Customer for the transaction x hours in the transaction x (**\$5.55/MWh** + Incremental Losses Charge / Energy Transfer in the Billing Period).

Plus

- (2) An Operating Reserve charge or other System Support Service charge when, in the opinion of the AESO, the transaction requires the procurement of incremental System Support Services and/or Operating Reserve.

Plus

- (3) Transaction Fee: **\$500.00** per Billing Period.

Terms: (a) System Access Service provided pursuant to this Rate Schedule is recallable on one (1) hour's notice. To the extent practical, service for Merchant Opportunity Service Customers taking service under this Rate Schedule shall be recallable in advance of service provided under Rate MTS in an Emergency.



**MOS 1 Hour**

**Merchant Opportunity Service (1 Month)**

Page 2 of 2

- (b) Rate MOS 1 Month is separately applicable at each Point of Exchange.
- (c) The minimum term for Rate MOS 1 Month is one (1) calendar month. The maximum term is one (1) calendar year.
- (d) When invoked by the AESO, Rate Rider E applies to customers under this rate schedule.
- (e) The Terms and Conditions form part of this Rate Schedule.



**UFLS Demand Under-Frequency Load Shedding Credit** Page 1 of 1

**Purpose:** The under-frequency load shedding credits compensate those Demand Customers who are connected to under-frequency load shedding devices and therefore face a higher risk of outage. In order to maintain the integrity of the AIES, the AESO shall have the right to require each Demand Customer to maintain a minimum of 50% of that Customer's aggregate load (across all PODs through which the Customer takes System Access Service) connected to an under-frequency load shedding device.

**Available to:** Customers served under the DTS Rate Schedule who, as directed by the AESO, install and activate an under-frequency load shed relay satisfactory to the AESO.

**Rate:** The credit is based on the relay setting and UFLS Capacity for each relay setting. The AESO provides no assurance as to the number or duration of any future outages.

UFLS Capacity shall be the share of the DTS Contract Capacity (expressed in MW) for each setting for which the Customer has agreed to be shed. The AESO from time to time may revise a Customer's total UFLS obligation to maintain the minimum of 50% of that Customer's aggregate load. The Customer must ensure the aggregate UFLS Capacity across all PODs through which the Customer takes System Access Service continues to meet the revised total UFLS obligation.

Relay Trip Setting	Credit (\$/MW of UFLS Capacity/month)
59.1 Hz	\$65.00
58.9 Hz	\$60.00
58.7 Hz	\$55.00
58.5 Hz	\$50.00
58.3 Hz	\$45.00
58.1 Hz	\$40.00
58.0 Hz	\$35.00

**Terms:** The Terms and Conditions form part of this Rate Schedule.



**PSC**                      **Primary Service Credit**                      Page 1 of 1

**Purpose:**                      The Primary Service Credit compensates customers whose interconnection does not include conventional transformation facilities owned by the TFO (including interconnections for customers who have purchased, own, and operate their transformers). The Primary Service Credit is provided in conjunction with a reduced maximum Local Investment in accordance with the Terms and Conditions of Service.

**Available to:**                      DTS Customers supplied under suitable long term contract, whose interconnection does not require or does not otherwise include TFO-owned transformation which steps the voltage down from transmission voltage to 25 kV or less, and associated low-voltage facilities.

**Rate:**                      The **Primary Service Credit** is a credit of:

- (a) **\$166.00/MW/month** of Billing Capacity in the Billing Period, plus
- (b) **\$7,522.00/month** multiplied by the Substation Fraction in the Billing Period.

Billing Capacity is as defined in Rate DTS.

**Terms:**                      (a) A reduced maximum Local Investment is available to Customers receiving this credit.

- (b) The Terms and Conditions form part of this Rate Schedule.



**STS**                      **Supply Transmission Service**                      Page 1 of 1

Applicable to:            Customers who supply electrical energy to the AIES from within Alberta.

Rate:                      Charges for STS in any one Billing Period shall be the Losses Charge, where:

The **Losses Charge** equals:

- Metered Energy in each hour × location specific loss factor × Pool Price

where “location specific loss factor” is defined in the ISO Rules and determined in accordance with ISO Rule 9.2.

For the purpose of calculating the Losses Charge under this STS Rate Schedule, Metered Energy shall be measured on a 15-minute interval.

**Regulated Generating Unit Connection Costs:**

An additional charge of **\$304.00/MW** per month for each MW of unit MCR applicable only to Regulated Generating Units, as identified in Appendix B of the rate schedules and only to the end of the base life year of the Regulated Generating Units as provided in the Terms and Conditions.

- Terms:
- (a) The STS rate is separately applicable at each POS.
  - (b) When invoked by the AESO, Rate Rider E applies to customers under this rate schedule.
  - (c) The Terms and Conditions form part of this Rate Schedule.



**IOS**                      **Import Opportunity Service**                      Page 1 of 1

Applicable to:            Customers importing electric energy into the AIES.

Available:                When sufficient transmission capacity exists to accommodate the capacity scheduled for service. This service shall be available a minimum of twenty-four (24) hours following execution of a System Access Service Agreement for Import Opportunity Service.

Rate:                      The charges for service per Billing Period shall be as follows:

- (1) The **Losses Charge** equals:
- Energy Transfer in each hour × location specific loss factor × Pool Price

where “location specific loss factor” is defined in the ISO Rules and determined in accordance with ISO Rule 9.2.

For the purpose of calculating the Losses Charge under this EOS Rate Schedule, Energy Transfer shall be measured on a 15-minute interval.

Plus

- (2) Transaction Fee: **\$500.00** per Billing Period.

- Terms:
- (a) System Access Service provided pursuant to this Rate Schedule is recallable on one (1) hour's notice.
  - (b) The rate is separately applicable at each Point of Exchange.
  - (c) When invoked by the AESO, Rate Rider E applies to customers under this rate schedule.
  - (d) The Terms and Conditions form part of this Rate Schedule.