

Background

In late 2005 and early 2006, the Alberta Electric System Operator (AESO) conducted stakeholder consultation on rates issues to be addressed in the AESO's 2007 General Tariff Application (GTA).

During the consultation, terms of reference for a *2006 Transmission Cost Causation Update* were developed and a preliminary report on the *Update* circulated for comment. The final report is not yet ready for distribution, although draft results have been provided to the AESO for inclusion in this discussion paper. Stakeholder consultation was also held on export, import, and merchant transmission tariffs, and the results of that consultation are also incorporated into this paper.

This discussion paper presents the basis for the AESO's 2007 rates proposal. Major changes to several rates are addressed, and proposed rate schedules are attached. Specific proposals in this paper are numbered sequentially, and the AESO invites stakeholders to provide comments on the proposals using the attached comment form.

Please note that separate consultation is being conducted on the AESO's 2007 terms and conditions, with a separate discussion paper being distributed concurrently.

Information provided in the 2007 rates consultation and in the processes leading to approval of the AESO's 2006 tariff can be found on the AESO's website at www.aeso.ca, by following the paths:

- Tariff ► Current Consultations ► 2007 Rates
- Tariff ► Previous Applications ► 2005-2006 Tariff Second Refiling
- Tariff ► Previous Applications ► 2005-2006 Tariff Refiling
- Tariff ► Previous Applications ► 2005-2006 Tariff Application

2006 Transmission Cost Causation Update

The AESO developed terms of reference for a *2006 Transmission Cost Causation Update* early in 2006, and distributed a preliminary report on the *Update* in April for stakeholder comment. Draft results have been provided to the AESO for inclusion in this discussion paper. These results are not expected to change in the final report, and in any event the final report will be the basis for the AESO's tariff application. The final report will be distributed as soon as it is available.

The final cost classification for the AESO's 2006 DTS rate, as based on the original *Transmission Cost Causation Study*, was provided in the response to Direction 6 in the AESO's 2005-2006 GTA Refiling on September 27, 2005, in Figure D6.2 (reproduced below).

Table D6.2 Functionalized and Classified Transmission Wires Costs ("Directed"), % of Total

| Function | Total | Classification | | | |
|--------------|---------------|----------------|--------------|--------------|--------------|
| | | CP | NCP | Usage | Customer |
| Bulk System | 41.0% | 24.1% | - | 16.9% | - |
| Local System | 17.1% | - | 14.0% | 3.1% | - |
| POD | 41.9% | - | 17.9% | - | 24.0% |
| Total | 100.0% | 24.1% | 31.9% | 20.0% | 24.0% |

Note: Totals may not add due to rounding

Directions in Decision 2005-096 and Decision 2006-132, and activities in the terms of reference for the *2006 Transmission Cost Causation Update*, identified additional analysis of three aspects of the cost classification:

- (a) the local system and point of delivery functionalization of costs;
- (b) the coincident peak and usage classification of bulk system costs; and
- (c) the non-coincident peak and customer classification of point of delivery costs.

The local system and point of delivery functionalization in the original *Transmission Cost Causation Study* has been reviewed for consistency with the system-related and customer-related costs defined in the AESO's terms and conditions of service. The functionalization is generally consistent with the Ts&Cs. However, there is not always perfect consistency due to limitations of the TFO cost data utilized in the cost causation study. For example, costs of advancing the looping of a portion of the transmission system would be considered customer-related costs in the Ts&Cs, but would not be identifiable in the TFO costs data. The impact of such costs, however, is expected to be minimal.

The AESO therefore proposes to retain the functionalization of local system and point of delivery costs developed in the original *Transmission Cost Causation Study*.

1. The 17.1% local system and 41.9% point of delivery functionalization developed in the original *Transmission Cost Causation Study* should be retained.

Next, the preliminary report on the *2006 Transmission Cost Causation Update* included significant analysis of the cost drivers for bulk transmission system lines. The final report supports the same conclusion, namely, that there is little, if any, correlation between transmission bulk line loading and total system load. It follows that if the rate for recovering bulk system costs is expected to be primarily reflective of cost causation, then charging on a coincident peak basis is not necessarily a justifiable or logical approach.

The AESO therefore proposes to revert to recovering the demand-related bulk system costs on a non-coincident peak basis, through a \$/MW charge based on billing capacity. Billing capacity reflects the service provided to individual load customers, and the bulk system is planned and built to accommodate that individual load as it occurs on the transmission system. Regardless of

the actual time and pattern of maximum stress on a bulk transmission line, the line must have enough capacity to provide service to the individual loads connected to the bulk system. The AESO therefore considers that billing capacity is reasonably reflective of cost causation for the bulk system demand-related costs. In addition, billing capacity as a billing determinant is a metric that an individual customer can respond to and manage, ultimately minimizing bulk system costs.

2. Based on lack of correlation between transmission bulk line loading and total system load, it is more appropriate to recover demand-related bulk system costs through a \$/MW charge based on billing capacity.

In the cost classification for the AESO's 2006 DTS rate, the demand-related classification determined through a minimum system analysis of bulk system costs was reduced to account for the lack of coincidence of POD loads with bulk system maximum stress. This reduction was re-examined based on the analysis in the *Update*. The reduction is calculated based on the percentage of peak AIL at the time of maximum loading on each bulk line, averaged for all bulk lines and weighted by line length. The resulting average value is 80.7%, which is higher than the 71.1% adjustment used in the classification for the AESO's 2006 rates. The demand-related classification of bulk system costs is accordingly increased slightly to 27.0%, and the usage-related classification of bulk system costs accordingly decreased to 14.0%.

The AESO proposes to recover 80.7% of demand-related bulk system costs through a billing capacity demand charge to reflect the analysis in the *2006 Transmission Cost Causation Update*.

3. The 80.7% adjustment to demand-related bulk system costs to reflect non-coincidence of POD load with bulk system maximum stress is appropriate, based on calculation at the time of maximum loading on each bulk line averaged for all bulk lines and weighted by line length.

The examination of the non-coincident peak and customer classification of point of delivery costs relied on the detailed examination of the project cost data conducted during development of the maximum investment function for the AESO terms and conditions of service. Based on the average cost function developed from cost data for projects completed from 1999-2005, point of delivery costs should be classified 40.0% as demand-related and 60.0% as customer-related. This compares to the 42.7% demand-related and 57.3% customer-related costs provided in Figure D6.2 above.

The AESO notes that both the original *Transmission Cost Causation Study* and the maximum investment function analysis provide similar results, and proposes to rely on the more detailed average cost function analysis for the final POD cost classification for its 2007 rates.

4. It is appropriate to use the average cost function analysis to determine point of delivery cost classification of 40% demand-related and 60.0% customer-related.

The final cost classification resulting from the 2006 *Transmission Cost Causation Update* is presented in Figure 1.

| Figure 1: Proposed 2007 Cost Classification, % of Total | | | | | |
|----------------------------------------------------------------|---------------|----------------|--------------|--------------|--------------|
| Function | Total | Classification | | | |
| | | CP | NCP | Usage | Customer |
| Bulk System | 41.0% | - | 27.0% | 14.0% | - |
| Local System | 17.1% | - | 14.0% | 3.1% | - |
| POD | 41.9% | - | 16.8% | - | 25.1% |
| Total | 100.0% | - | 57.8% | 17.1% | 25.1% |

Note: Totals may not add due to rounding

As the bulk system and local system functions are classified with similar components, the AESO proposes to combine both functions in its rate design to provide better alignment with the system-related and customer-related costs defined in the AESO's terms and conditions of service. The AESO therefore proposes to combine those functions in the classification to be used for 2007 rates, as provided in Figure 2.

| Figure 2: Proposed Cost Classification for 2007 Rates, % of Total | | | | | |
|--------------------------------------------------------------------------|---------------|----------------|--------------|--------------|--------------|
| Function | Total | Classification | | | |
| | | CP | NCP | Usage | Customer |
| System | 58.1% | - | 41.0% | 17.1% | - |
| POD | 41.9% | - | 16.8% | - | 25.1% |
| Total | 100.0% | - | 57.8% | 17.1% | 25.1% |

Note: Totals may not add due to rounding

5. The proposed costs classification for 2007 rates presented in Figure 2 is appropriate, based on the analysis conducted and conclusions reached.

The resulting Rate DTS is included in the proposed rate schedules which accompany this discussion paper.

PODs Serving Smaller Loads

In Decision 2005-132 the EUB provided the following direction related to the point of delivery charge in the DTS rate:

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)*

The AESO considers that 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 its customer contribution policy study, the AESO examined in detail the costs for load services interconnected from 1999 to 2005. The available data did not break down costs into the three components listed above, although data was available for radial line and substations (which includes transformation and most buswork, switchgear, communication equipment, and sitework).

Radial line costs were found to correlate well to line length, and poorly to DTS capacity. The cost for radial line as a function of DTS capacity is as follows:

$$\text{Line Costs} = \$1.813 \text{ million} + (\$0.012 \text{ million/MW} \times \text{DTS Capacity})$$

Substations costs exhibited a stronger correlation with DTS capacity:

$$\text{Substation Costs} = \$1.848 \text{ million} + (\$0.122 \text{ million/MW} \times \text{DTS Capacity})$$

Given the poor correlation of radial line costs to DTS capacity, the observed scatter of project costs as a function of DTS capacity observed in the data provided in the AESO 2006 GTA and Refiling is not unreasonable. Based on total project costs, the AESO concluded in its contribution policy study that average customer-related costs for interconnection project standard facilities could be reasonably represented by the following cost function:

$$\text{Point of Delivery Costs} = \$4.099 \text{ million} + (\$0.162 \text{ million/MW} \times \text{DTS Capacity})$$

The contribution policy study also found that small load services have not been interconnected in recent history. Specifically, no load services smaller than 5.3 MW have been interconnected since 1999 and none are currently in the project queue. The AESO therefore is unable to quantitatively assess whether the costs of substations serving small loads would differ from the costs of substations serving larger loads. However, the AESO has no expectation 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.

Point of delivery costs above and below various breakpoints were also examined for the data included in the contribution policy study. There appeared to be no clear breakpoint which provided higher correlation factors both above and below the breakpoint.

The AESO notes, however, that the contribution policy study analysis reflects two inherent characteristics: the projects represent recent history, and the projects were interconnected through typical substation and line facilities. Although there were no small projects with those characteristics interconnected to the transmission system from 1999 to 2005, there are currently 68 services with DTS capacity of 5 MW or less existing on the transmission system. The AESO believes that these small services have unusual characteristics which would result in a different cost function than that determined from the contribution policy study data.

The existing small services appear to have arisen for a variety of reasons, summarized as follows:

- (a) They 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.” In this case, there is no physical substation associated with the isolated community, and there would be no actual fixed substation costs incurred in providing service to these communities. Furthermore, if those communities were connected to the electric system their small capacities would likely lead to connection through a distribution network rather than directly to the transmission system.
- (b) There are some small loads connected through unconventional facilities such as metering transformers rather than load transformers. Such unconventional connections incur lower costs than connections through conventional substations. The AESO understands that the lower costs of the unconventional connections would likely be the reason that those loads are connected to the transmission system rather than a distribution network. These unconventional connections would in that case incur lower fixed costs than connections through a conventional substation.
- (c) Other small loads were interconnected to the transmission system when utilities were vertically-integrated, and the AESO has been unable to determine project costs for such interconnections. However, a reasonable assumption seems to be that, since a distribution network can generally serve loads up to 5 MW and even larger, a transmission interconnection was likely a less expensive alternative for the specific circumstances at the time (possibly due to proximity to the transmission system). If a transmission interconnection was less expensive than a distribution interconnection, it is likely that it would not be well-represented by the cost function provided above and would incur lower fixed costs than “typical” transmission interconnections.

The AESO therefore concludes that the existing small (up to 5 MW) load services would exhibit a cost function different from and lower than the average cost function for larger load services, if data was available for such interconnections. The AESO also considers that a 5 MW breakpoint, as adopted in the AESO 2006 tariff, remains an appropriate threshold below which a service would be considered “small”.

Since existing small (up to 5 MW) load services represent a cost function that differs from that of larger services, the AESO proposes a permanent, separate rate class for such services. The AESO further proposes that this rate class be “grandfathered” — that is, closed to all services other than load services with DTS contract capacities of 5 MW or less as of January 1, 2006 — for the following reasons:

- (a) The existing small services were interconnected prior to 1999 under significantly different tariff structures. Had those services been faced with the current tariff structure applicable to larger services, it can be expected that they would not have interconnected to the transmission system. It is inequitable to now impose a new and materially different tariff structure on those services with no other option available.
- (b) Based on the available information and analysis, the cost function for existing small load services would exhibit a cost function different from and lower than the average cost function for larger load services. It is therefore appropriate that a different rate class be permanently available for those services.
- (c) The small load rate class should be closed to new services, as interconnection decisions with respect to new services would be based on the current tariff structure. For example, new services, whether small or large, would interconnect under the current contribution policy and would be evaluated based on the cost of a transmission interconnection under current rates. They should therefore be served as part of the standard rate class, rather than the “grandfathered” one.
- (d) The small load rate class should be available to services with DTS contract capacities up to 5 MW as of January 1, 2006, which was the effective date of the 2006 tariff that first introduced a customer component as part of the DTS point of delivery charge. A January 1, 2006 date recognizes the interim nature of the relief offered to small services in the AESO’s 2006 tariff and also avoids the potential of services now requesting contract capacity reductions solely to take advantage of the grandfathered rate.

The AESO therefore proposes the addition of a permanent closed “GTS” (“Grandfathered” Demand Transmission Service) rate to be available to any service with DTS contract capacity of 5 MW or less on January 1, 2006 and which is the sole service at a substation.

This service would have a demand-based POD charge which would result in the same POD charge as would apply to a 5 MW DTS service. The GTS demand-based POD charge would apply no matter what the billing capacity for the service is in the billing period. For example, a load with a 4 MW contract capacity could be charged based on a 7 MW billing capacity due to actual load or ratchet provisions in the billing period. The AESO notes that a billing capacity above 5 MW would result in a higher POD charge on the GTS rate than on the DTS rate, and would therefore expect a customer to transfer to the DTS rate if capacity was expected to continue above 5 MW. Transfers from the GDS rate could not be reversed. That is, once a customer left the GDS rate the service could not return to it. As the choice to leave would be made under the current tariff structure, the AESO considers it appropriate to restrict a return to the GTS rate.

The GTS rate would also not be available to load services at substations with multiple points of service (that is, any combination totalling two or more DTS, STS, or DTS and STS services). All such existing substations have total contract capacities greater than 5 MW, and the AESO accordingly expects the cost of such substations to be represented by the cost function determined in the contribution policy study analysis. As well, the customer charge for a DTS service at such a substation is reduced by the application of the substation fraction, and the service would accordingly receive a lower POD charge than otherwise. The GTS rate is therefore proposed to be restricted to services which are the sole transmission service at a substation (that is, services with a substation fraction of 1.000). The AESO notes that the GTS service would apply to both direct-connect and DISCO customers of the AESO, as the above discussion regarding the distinct cost structure of such services would apply in both instances.

The resulting Rate GTS is included in the proposed rate schedules which accompany this discussion paper.

6. Rate GTS in the proposed rate schedules will be provided for services with DTS contract capacities of 5 MW or less as of January 1, 2006 and which are the sole service at a substation.

The current DTS rate will continue as the AESO's "standard" load service rate with demand and customer components in the POD charge based on the POD cost classification proposed earlier in this discussion paper.

Backup Transmission Service Rate

The requirement for a standby transmission service rate was raised during the AESO's 2006 GTA, and the AESO committed to examining the requirement for such a rate in its next tariff application. The distinguishing feature of a backup or standby service is that the service is required for periods of short duration no more than a few times per year. The need for backup service may be unable to be predicted (for example, to allow a load process to continue uninterrupted when on-site generation suffers an unexpected outage) or may be scheduled (for example, during scheduled generator maintenance).

The AESO has examined the costs caused by such short-duration and intermittent use of the transmission system. Backup service would be available only under normal operating conditions and only when transmission capacity is available. In general, the expectation is that additional system facilities would not be planned to provide backup service. Backup service would therefore not entail long contract commitments.

Given the short-duration and infrequent nature of the service, backup service would generally not affect short-term transmission planning, either, and should therefore not entail ratchets or contract minimums. However, if unrestricted access were provided to such a service, it would be expected that such a service without contract, ratchet, or minimum provisions would attract use beyond true short-duration, infrequent needs, and would begin to impact short-term management of the transmission system.

The AESO therefore proposes a rate structure which should provide self-selection on the part of customers, by charging a rate which would become more expensive than standard DTS service when used for more than 10% of the time. The 10% load factor limit would generally allow 5 weeks usage per year which should have minimal impact on short-term management and operation of the transmission system.

The primary difference between the Backup Transmission Service (BTS) and the “standard” Demand Transmission Service (DTS) is in the System and Point of Delivery Charges. All components of the System Charge are converted to a usage (\$/MWh) charge which, at 10% load factor, would provide the same revenue under both the BTS and DTS rates. Above a 10% load factor, it would be less expensive for a customer to take service under Rate DTS. This should encourage customers to make an appropriate choice of rate for their service requirements.

The BTS rate will not include a Point of Delivery charge. No investment in customer-related facilities will be made for service on Rate BTS. Any customer-related facilities at the customer’s site will be paid for through the standard DTS rate (through investment with recovery in the rate), through customer contribution, or through customer ownership of facilities.

The AESO assumes that backup service will generally be contracted for at a POD in addition to standard service. The \$/MWh system charge would therefore apply to usage in any hour above DTS contract capacity.

All other DTS charges (operating reserve charge, voltage control charge, and other system support service charge) will apply to Rate BTS, since all are charges which apply only if the customer utilizes the service during the month.

Based on 2005 billing history, the AESO notes that about 50 DTS sites totaling about 4,100 MW of billing capacity have load factors less than 10%. The AESO expects the majority of these sites to move to the BTS rate, as well as additional capacity at other sites with higher load factors. All

such migration from the DTS rate to the BTS rate will require a re-assessment of previous customer contribution calculations and will be subject to applicable DTS contract capacity reduction provisions of the AESO's terms and conditions.

The AESO is currently determining appropriate rate levels and criteria for Rate BTS as described above. Development of the rate will be finalized in the near future and Rate BTS will be included in the AESO's 2007 tariff application.

7. A rate with a \$/MWh System Charge equivalent to the DTS System Charge at 10% load factor and no POD Charge is an appropriate backup service for short-duration, infrequent use of the transmission system.

Export and Import Rates

The AESO currently provides export and import opportunity service rates. During 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. The AESO has pursued the development of such rates based on the proposed domestic service rates included in this discussion paper.

With respect to export rates, the AESO proposes the export rate structure summarized in Figure 1.

| Figure 2: Export Rate Service Structure | | | | |
|------------------------------------------------|---------------------|-------------------------|--------------------|--------------------|
| Service Name | Demand Transmission | Export Transmission | Demand Opportunity | Export Opportunity |
| Rate Code | DTS | XTS | DOS | XOS |
| System Charge | Postage Stamp | Postage Stamp Less UFLS | Incremental | Incremental |
| POD Charge | Postage Stamp | None | None | None |
| Losses | None | None | Location-Specific | Location-Specific |
| Operating Reserve | Postage Stamp | Postage Stamp | None | None |
| Voltage Control | Postage Stamp | Postage Stamp | None | None |
| Other System Support | Postage Stamp | Postage Stamp | None | None |
| Curtailement Priority | 29 | Pre-29 | 6-8 | 5 |
| Contract Term | Minimum 5 Year | Minimum 1 Year | 8 Hours to 1 Year | 8 Hours to 1 Year |

Non-Recallable Export Transmission Service Rate XTS will be similar in structure to Demand Transmission Service Rate DTS, with the following exceptions:

- (a) The XTS Interconnection Charge will be the DTS System Charge reduced by the amount of the 59.1 Hz UFLS Credit, recognizing that XTS capacity will be curtailed prior to domestic load being shed under UFLS.
- (b) The XTS Interconnection Charge will not include the equivalent of a Point of Delivery Charge as there are no “customer-related” facilities associated with export service.
- (c) All XTS charges will be expressed as amounts per megawatt hour (\$/MWh or percentage of pool price). Amounts will be converted where necessary from DTS amounts per megawatt at 90% load factor.
- (d) A minimum charge based on 90% of scheduled capacity will apply to Rate XTS.
- (d) XTS capacity will be curtailed immediately prior to curtailed of non-recallable domestic load (currently Step 29 of the supply shortfall management procedure detailed in OPP 801).
- (e) XTS will require a minimum contract term of 1 calendar year, but may include different monthly amounts during the year.

The resulting Rate XTS is included in the proposed rate schedules which accompany this discussion paper. The AESO therefore proposes:

8. Rate XTS in the proposed rate schedules will be provided for non-recallable export transmission service.

The AESO currently provides three levels of Demand Opportunity Service which differ in price and curtailment priority: DOS 7 Minutes, DOS 1 Hour, and DOS Term. As export service is scheduled “firm” within the hour, there can be no export opportunity service offered which is comparable to DOS 7 Minutes. The AESO therefore proposes to offer two export opportunity services which are generally comparable to DOS 1 Hour and DOS Term — namely, XOS 1 Hour and XOS 1 Month.

Both XOS rates will include the variable component of the DTS System Charge as representative of variable wires operating costs. As well, both will include an additional contribution to the fixed costs of the Alberta-British Columbia and Alberta-Saskatchewan inter-ties. Based on the *2006 Transmission Cost Causation Update*, that additional contribution is estimated to be \$0.41/MWh.

Similar to the curtailment priority of DOS 1 Hour and DOS Term, XOS 1 Hour will be curtailed before XOS 1 Month. Curtailment priority will be similarly reflected in transfer scheduling priority: XTS will have scheduling priority in advance of XOS 1 Month, which will have scheduling priority in advance of XOS 1 Hour. The XOS 1 Month rate will be two times the XOS 1 Hour rate reflecting the curtailment and scheduling priority.

The AESO notes that procedures relating to curtailment, scheduling, and release of unscheduled capacity will be addressed in the AESO's Operating Policies and Procedures and implemented primarily through an OASIS (Open Access Same-time Information System).

The resulting Rates XOS 1 Hour and XOS 1 Month are included in the proposed rate schedules which accompany this discussion paper. The AESO therefore proposes:

9. Rates XOS 1 Hour and XOS 1 Month in the proposed rate schedules will be provided for export opportunity service.

In stakeholder consultation on export and import rates the AESO has 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 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:

9. Rates IOS will continue to be provided for import opportunity service.

Merchant Export and Import Rates

During stakeholder consultation on export and import rates the AESO 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 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 energy transfers over a merchant line would not utilize. (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 costs 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. Those costs are estimated to be \$0.62/MWh based on the *2006 Transmission Cost Causation Update*.

The AESO therefore proposes:

10. Rates XTS, XOS 1 Hour, and XOS 1 Month be reduced by the share of costs attributable to the existing inter-ties when applied to service over merchant inter-ties.

Specific schedules for Rates MTS, MOS 1 Hour, and MOS 1 Month for merchant inter-tie export services are not included in the proposed rate schedules distributed with this discussion paper, but will be similar to Rates XTS, XOS 1 Hour, and XOS 1 Month.

The AESO does not believe a modified rate is required for imports over merchant inter-ties, as the losses charge which is the major component of Rate IOS will be determined based on a location specific loss factor for the merchant interconnection.

Primary Service Credit

The Primary Service Credit in the AESO's 2006 tariff was developed on a different basis than that which underlies the demand transmission service rate. The premise of the credit is that it reduces the Point of Delivery Charge for Rate DTS to reflect customer ownership of the substation. However, detailed information on the substation component of point of delivery costs was not available during the 2006 tariff proceeding.

More detailed information is available in the customer contribution policy study analysis. The analysis establishes the following average cost functions for line and substation costs for projects interconnected from 1999 to 2005:

$$\text{Line Costs} = \$1.813 \text{ million} + (\$0.012 \text{ million/MW} \times \text{DTS Capacity})$$

$$\text{Substation Costs} = \$1.848 \text{ million} + (\$0.122 \text{ million/MW} \times \text{DTS Capacity})$$

These cost functions can be used to estimate the level of primary service credit for customer ownership of a substation. That credit should reflect $\$0.122 \div (\$0.012 + \$0.122) = 91\%$ of demand-related charges, and $\$1.848 \div (\$1.813 + \$1.848) = 50\%$ of customer-related costs.

Based on the Rate DTS Point of Delivery Charge of \$658.00/MW and \$22,745.00/month, the Primary Service Credit becomes:

$$\text{Primary Service Credit} = \$599.00/\text{MW} + (11,373.00/\text{month} \times \text{Substation Fraction})$$

The eligibility criteria as defined in the current Primary Service Credit remain applicable. That is, the Primary Service Credit would only be available to customers whose standard interconnection facilities would include a transformer, who purchase, own, and operate their own transformation, and who thereby reduce the investment in transformation and customer-related facilities by the TFO.

The AESO therefore proposes:

11. The Primary Service Credit level should be increased to $\$599.00/\text{MW} + (11,373.00/\text{month} \times \text{Substation Fraction})$ based on project costs analysis in the customer contribution policy study.



Next Steps

The AESO would appreciate stakeholder feedback on the proposals discussed in this paper using the attached comment form. Stakeholders are requested to return all comments to the AESO by Tuesday, July 11, 2006. The AESO will post all comments on its website.

Comments are to be provided to John Martin at john.martin@aeso.ca and copied to Maureen Winslow at maureen.winslow@aeso.ca. If you have questions on the 2007 rate matters discussed in this paper or on the consultation process, please contact John Martin at (403) 539-2465 in Calgary or by e-mail at the above addresses.

The AESO expects to file its 2007 tariff application in late July 2006, for rates to be effective on April 1, 2007.

All information on the 2007 rates consultation is available on the AESO's website by following the path [Tariff](#) ► [Current Consultations](#) ► [2007 Rates](#).