



March 26, 2008

*Submitted via Digital Data Submission System*

Alberta Utilities Commission  
Utilities Division  
Fifth Avenue Place  
4th Floor, 425 – 1st Street SW  
Calgary, Alberta  
T2P 3L8

Attention: Jamie Cameron, Application Officer

Dear Jamie:

**Re: Responses to Information Requests in AESO 2007 General Tariff Application Refiling (1558815)**

Attached are the AESO's responses to information requests received pursuant to the above-noted application.

If you have any questions on these information responses, please contact me at (403) 539-2465 or by e-mail to [john.martin@aeso.ca](mailto:john.martin@aeso.ca).

Yours truly,

*[original signed by]*

John Martin  
Director, Tariff Applications

cc: Heidi Kirrmaier, Vice-President, Regulatory, AESO

**Reference:** Refiling, Direction 7, Pages 11-12

**Preamble:** The AESO noted on page 11 of 35, in section 4, of its refiling, the Board Directive that:

“The classification of POD costs proposed by the AESO in section 4.3.4 of the Application and as refined by the Board is approved.”

The AESO states on page 12 of 35, in section 4 of its refiling that:

“In the AESO’s 2007 GTA, the AESO considered that “the customer and first demand components of the [proposed] cost function can be considered representative of the fixed cost of multiple-service substations” (AESO 2007 GTA, section 4, page 21). The same approach was assumed in the AESO’s responses to information requests submitted on November 19, 2007, as part of the comment process on the EUB’s proposed approach to the construct of the POD cost function.

However, **Direction 5 of Decision 2007-106 requires the AESO to implement a POD cost function that is significantly different from that proposed in the AESO’s GTA.** That POD cost function is based on a continuous power curve, reflective of significant economies of scale with increasing capacity, and considered “more robust and desirable” by the EUB (Decision 2007-106, page 51). The customer (fixed) component of the directed cost function is \$0.894 million, and consistent with the clarification provided in the EUB’s letter in the AESO’s 2005-2006 GTA, the AESO has apportioned that customer component (and no demand components) amongst the customers served by a particular substation through the application of the substation fraction.”

The final proposed POD cost function proposed by the AESO in its Reply Argument<sup>1</sup> was:

Point of Delivery Costs = \$0.947 million  
+ (\$0.621 million/MW × first 7.5 MW of DTS Capacity)  
+ (\$0.154 million/MW × next 42.5 MW of DTS Capacity)  
+ (\$0.047 million/MW × DTS Capacity above 50 MW)

The POD cost function approved by the Board in Decision 2007-106<sup>2</sup> was:

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

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<sup>1</sup> AESO Reply Argument, page 22.

<sup>2</sup> Decision 2007-106, page 51.

**Request:**

- (a) Please explain the extent to which the approach on page 12 of the refiling (concerning discontinuing the use of the substation fraction for the first 7.5 kW of demand) is consistent with the Board directive quoted on page 11 of the refiling (concerning Board approval of the classification of POD costs proposed by the AESO in section 4.3.4 of the Application and as refined by the Board).
- (b) Given that the Board had directed a POD Cost function that includes the substation fraction for the first 7.5MW of demand, whereas the refiling application appears to propose that the use of the substation fraction be eliminated for the first 7.5MW of demand, please identify and explain the significance of the "significant differences" which would justify this change.
- (c) Does the AESO consider that its final proposed POD cost function is reflective of significant economies of scale? If not, why not?
- (d) Please confirm that the form of the POD cost functions listed in the preamble are structurally very similar, in that both involve a series of linear lines joined together.
- (e) Please explain why the AESO considers that the difference in the y-intercept and first 7.5 MW of demand is significant enough to remove its use of a substation fraction for the first 7.5 MW of demand without Board direction to do so.
- (f) Please explain why the AESO did not put forth a proposal to remove its use of a substation fraction for the first 7.5 MW of demand when providing comment on the Board's proposed POD cost function.
- (g) Please confirm that by removing its proposal to use the substation fraction on the first 7.5 MW of demand, the MW-months of demand for the first 7.5 MW of demand are increased from 32,514.8 to 36,796.1, and the total MW-months for all demand increases from 114,648.1 to 118929.4.
- (h) Please provide recalculated AESO DTS rates using the value of 32,514.8 MW-months for the first 7.5 MW of demand.
- (i) Please provide recalculated bill impact schedules based on the rates calculated in h) above. Please also provide spreadsheets with formulas in place of hard-coded values.
- (j) Please provide updated rate schedules which include the recalculated DTS rates from h) above.

- (k) Please also update any other rate schedules and terms and conditions impacted by the reinstatement of the demand related substation fraction removal (e.g. investment policy).

**Response:**

- (a) The AESO's response on page 12 of section 4 of the refiling was intended to be consistent with Direction 7 of Decision 2007-106 quoted on page 11 of the refiling, based on the following rationale.

The POD cost function establishes the basis for the DTS POD charge, the maximum investment level, and the Primary Service Credit in the AESO's refiled tariff. However, the POD cost function results from an examination of substation costs, and does not take into account the number of customers served at a substation or reflect how those costs might be shared if more than one customer is interconnected there. Accordingly — and as the AESO would expect to be appropriate in the context of the cost function — neither section 4.3.4 of the AESO's Application nor Direction 7 made any reference to substation fraction.

The actual rate design is developed after the underlying cost function is established, including the application of the substation fraction as required. As the EUB did not specifically direct the application of the substation fraction in Decision 2007-106, the AESO reviewed the whole of the EUB's decision and its directions to determine if and how the substation fraction should be appropriately incorporated into the POD charge and other components of the tariff. The AESO's considerations were summarized in its response to Direction 7, and are discussed in more detail in parts (b) to (e) below.

- (b) The AESO does not understand Decision 2007-106 to provide any specific direction with respect to either inclusion or exclusion of the substation fraction. As noted in part (a) above, the substation fraction was not referred to in Direction 7 regarding the DTS rate or elsewhere in the Decision.

The AESO considers the directed POD cost function and the cost function proposed in its 2007 GTA to be founded on "significantly different" bases. These differences occur in three respects, as discussed below.

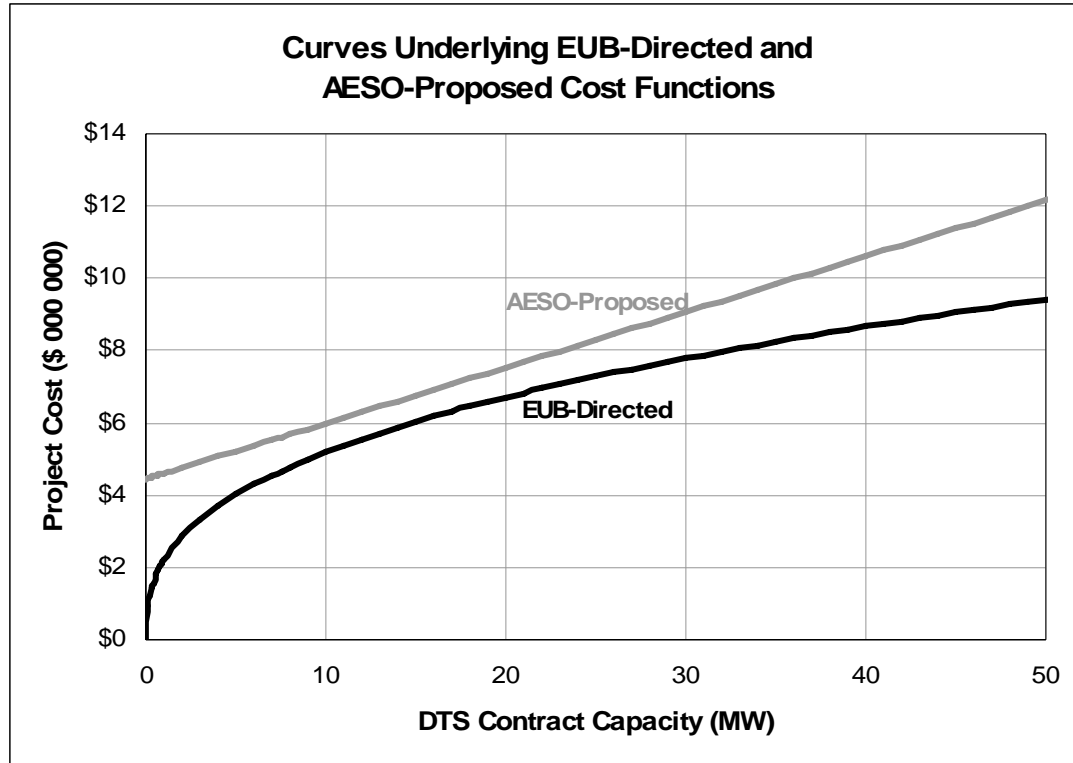
First, the cost functions were based on fundamentally different curves. The EUB-directed POD cost function was based on the following power curve:

$$\text{Costs} = \$2,213,108.54 \times \text{MW}^{0.37}$$

The AESO-proposed POD cost function was based on the following straight line:

$$\text{Costs} = \$4,451,000 + (\text{MW} \times \$154,000)$$

The differences in those equations are illustrated in the following figure.



These underlying curves were further modified in developing the final cost function, but the curves themselves are fundamentally different.

Second, the underlying curve for the AESO-proposed POD cost function had a fixed cost of \$4.451 million. In its application, the AESO proposed an interpolated function between 0 MW and 7.5 MW, as the AESO's analysis did not include any projects of less than 7.5 MW capacity. The AESO considered the fixed cost and the interpolated demand cost up to 7.5 MW together to be representative of the underlying fixed cost of \$4.451 million, and that, when considering the corresponding rate design, such costs should therefore be shared between multiple customers sharing a substation.

The underlying curve for the EUB-directed POD cost function had no fixed cost component. The EUB also questioned the conceptual appropriateness of a fixed cost component in Decision 2007-106 (page 55):

*First, the Board is not convinced that a zero intercept for a POD cost function is unrealistic or inappropriate. No explanation has been advanced in this proceeding for constructing a POD to provide a DTS capacity at a prudent cost in excess of zero for a demand of zero.*

With no fixed cost component, the concept of sharing of fixed costs appears to have no place.

Finally, the AESO-proposed cost function included a fixed component and an interpolated demand component that intercepted the underlying curve at 7.5 MW. The fixed and interpolated demand components were considered representative of the

underlying fixed costs of \$4.451 million. The 7.5 MW breakpoint between the interpolated component and the underlying curve was considered to represent a physical quantity in that it appears to be the smallest size of service currently interconnecting to the transmission system.

The EUB-directed cost function is based on a smooth, continuous power curve with no breakpoints. The EUB also rejected the AESO's view of the 7.5 MW breakpoint in Decision 2007-106 (page 54):

*The assertion that physical characteristics of a POD change at 7.5 MW was not substantiated. The Board agrees with the PPGA that a 7.5 MW breakpoint has not been demonstrated to represent any meaningful physical characteristics, and is arbitrary.*

The AESO therefore concluded that the directed POD cost function and the cost function proposed in its 2007 GTA were "significantly different" based on the factors described above, namely:

- fundamental differences in the underlying curves,
- differences in fixed cost components, and
- differences in breakpoint considerations.

- (c) Yes, the AESO considers its final proposed cost function as presented in its Reply Argument to reflect significant economies of scale. The AESO also understands that the EUB determined greater economies exist than those reflected in the AESO-proposed cost function, based on comments in Decision 2007-106 (page 44):

*However, the Board is not persuaded by the assertions of the AESO and PPGA that diseconomies of scale occur that to such an extent as to offset the contributors to economies of scale described by DUC.*

"Economy of scale" is defined as "the decrease in unit cost of a product or service resulting from large-scale operations, as in mass production" (*American Heritage Dictionary*, 4th edition). In other words, total cost increases at a lower rate than total capacity. The economies of scale of the AESO's final proposed cost function and the EUB-directed cost function are compared on that basis in Table 001 (c) below. Both functions exhibit economies of scale at all capacity levels in that a doubling of capacity results in less than a doubling of costs, and the economies of scale are generally similar between the two cost functions. However, compared to the EUB-directed cost function, the AESO-proposed cost function exhibits somewhat lower economy of scale (that is, higher cost increases) for contract capacities below 7.5 MW, and somewhat higher economy of scale (that is, lower cost increases) above 50 MW.

Table 001 (c) Comparison of Economies of Scale of AESO-Proposed and EUB-Directed Cost Functions

DTS Capacity		AESO-Proposed POD Cost Function		EUB-Directed POD Cost Function	
MW	Increase %	Cost \$ 000 000	Increase %	Cost \$ 000 000	Increase %
0.1	—	\$1.01	—	\$0.94	—
0.2	100%	\$1.07	6%	\$0.99	5%
0.4	100%	\$1.20	12%	\$1.10	10%
0.8	100%	\$1.44	21%	\$1.30	18%
1.6	100%	\$1.94	34%	\$1.70	31%
3.2	100%	\$2.93	51%	\$2.50	47%
6.4	100%	\$4.92	68%	\$4.11	64%
12.8	100%	\$6.42	30%	\$5.59	36%
25.6	100%	\$8.39	31%	\$7.20	29%
51.2	100%	\$12.21	45%	\$9.27	29%
102.4	100%	\$14.61	20%	\$12.04	30%

- (d) Confirmed with respect to the POD cost functions. However, the functions were founded on significantly different bases as discussed in part (b) above.
- (e) As discussed in part (b) above, the AESO understood Decision 2007-106 to provide no specific direction to either include or exclude the substation fraction in the DTS POD charge, the maximum investment level, or the Primary Service Credit. Also as discussed in part (b), the EUB-directed cost function was founded on a significantly different basis than the AESO-proposed cost function, which led the AESO to re-examine the rate design (including application of the substation fraction) for the refiling.

In particular, as explained in the AESO's response to Direction 7 in the refiling, the AESO considered that "the customer and first demand components of the [proposed] cost function can be considered representative of the fixed cost of multiple-service substations" (AESO 2007 GTA, section 4, page 21). The EUB, in developing its directed cost function, incorporated additional data points below 7.5 MW and utilized a power curve, both of which suggested a much smaller fixed cost component was more appropriate. As well, the EUB considered the 7.5 MW breakpoint to be arbitrary and added an additional breakpoint at 17 MW, from which the AESO interpreted that the substation fraction could potentially apply to either more or less than 7.5 MW of demand.

During the course of this re-examination, the AESO re-assessed the approach proposed in its reply argument (which was continued in the comment process on the EUB's proposed approach to the construct of the POD cost function in November 2007) and concluded this approach rendered irrational results. Essentially, applying the substation fraction to the 7.5 MW demand component implies that the total cost for a substation serving two DTS customers would be less than the cost for a substation serving one customer as large as the sum of the two. This irrational outcome is illustrated in Table 001 (e)-1.

Table 001 (e)-1 Comparison of Total Substation Costs When Substation Fraction Is Applied to Fixed and 7.5 MW Demand Components of Cost Function, \$ 000 000

Substation Capacity	One Customer at Substation		Two Equal Customers at Substation		
	Customer Capacity	Substation Cost	Per-Customer Capacity	Per-Customer Cost	Substation Total Cost
0 MW	0 MW	\$0.9	0 MW	\$0.4	\$0.9
2 MW	2 MW	\$1.9	1 MW	\$0.7	\$1.4
4 MW	4 MW	\$2.9	2 MW	\$1.0	\$1.9
6 MW	6 MW	\$3.9	3 MW	\$1.2	\$2.4
7.5 MW	8 MW	\$4.7	3.75 MW	\$1.4	\$2.8
8 MW	8 MW	\$4.8	4 MW	\$1.5	\$2.9
<b>10 MW</b>	<b>10 MW</b>	<b>\$5.1</b>	<b>5 MW</b>	<b>\$1.7</b>	<b>\$3.4</b>
12 MW	12 MW	\$5.4	6 MW	\$2.0	\$3.9
15 MW	15 MW	\$6.0	7.5 MW	\$2.3	\$4.7

As shown in the bolded line in the table, when the substation fraction is applied to the fixed and 7.5 MW demand components of the POD cost function, two 5 MW customers at a substation imply the total cost of the substation serving them (a total of 10 MW) is \$3.4 million, while the cost of a similar substation serving a single 10 MW customer is \$5.1 million. (The AESO notes the average billing capacity of customers where bill impact is greater than 10% is 5.0 MW, as provided in Schedule B-9 of the AESO's response to Direction 9 in its refiling. The majority of such customers — 55 out of 63 — are at substations serving two or more customers.) Adding customers to a substation without increasing substation capacity should not imply that total substation cost decreases.

The AESO therefore revisited the application of the substation fraction, and reviewed the original direction provided in the EUB's clarification letter of October 21, 2005, in the AESO's 2005-2006 GTA refiling proceeding. That direction was clear that just the customer (or fixed) charge component of the DTS POD charge was to be apportioned amongst the customers served by a particular substation. The AESO accordingly examined the total cost implications when the substation fraction is applied to just the fixed component and not to any of the demand components of the POD charge. The outcome is illustrated in Table 001 (e)-2.

The bolded line in the new table shows that, when the substation fraction is applied to just the fixed component of the POD cost function for two 5 MW customers at a substation, it is implied that the total cost of the substation serving them (a total of 10 MW) is \$5.9 million, while the cost of a similar substation serving a single 10 MW customer is \$5.1 million. Adding customers to a substation without increasing total substation capacity implies that total substation cost increases somewhat.

Table 001 (e)-2 Comparison of Total Substation Costs When Substation Fraction Is Applied to Just Fixed Component of Cost Function, \$ 000 000

Substation Capacity	One Customer at Substation		Two Equal Customers at Substation		
	Customer Capacity	Substation Cost	Per-Customer Capacity	Per-Customer Cost	Substation Total Cost
0 MW	0 MW	\$0.9	0 MW	\$0.4	\$0.9
2 MW	2 MW	\$1.9	1 MW	\$1.0	\$1.9
4 MW	4 MW	\$2.9	2 MW	\$1.5	\$2.9
6 MW	6 MW	\$3.9	3 MW	\$2.0	\$3.9
7.5 MW	8 MW	\$4.7	3.75 MW	\$2.3	\$4.7
8 MW	8 MW	\$4.8	4 MW	\$2.5	\$4.9
<b>10 MW</b>	<b>10 MW</b>	<b>\$5.1</b>	<b>5 MW</b>	<b>\$3.0</b>	<b>\$5.9</b>
12 MW	12 MW	\$5.4	6 MW	\$3.5	\$6.9
15 MW	15 MW	\$6.0	7.5 MW	\$4.2	\$8.4

The AESO considers this outcome to be more rational. The result was reviewed with the AESO's transmission system planners, who suggested that when additional customers are served by a substation, costs are usually incurred for additional metering equipment, additional breakers, and additional SCADA and protection equipment, and occasionally for additional high-voltage buswork and substation expansion.

Therefore, in its refiling the AESO applied the substation fraction to just the fixed component of the DTS POD charge, for the reasons provided above, namely:

- applying the substation fraction to both the fixed and 7.5 MW demand components of the POD charge resulted in an irrational outcome;
- the original direction provided that only fixed costs be apportioned between customers at a shared substation; and
- applying the substation fraction to just the fixed component of the POD charge resulted in a more rational outcome.

The AESO considered these reasons substantive enough to remove the use of the substation fraction from the first 7.5 MW demand component of the POD charge, given it did not find Decision 2007-106 to provide any specific direction to either include or exclude the substation fraction in the DTS POD charge.

For clarity, the AESO notes that applying the substation fraction to both the fixed and 7.5 MW demand components of the POD charge results in an irrational outcome for all POD charges proposed in this proceeding prior to and in Decision 2007-106, including those in the AESO's application and its reply argument, those discussed by the EUB, the AESO, and DUC in the comment process on the EUB's proposed approach to the construct of the POD cost function in November 2007, and that directed by the EUB in Decision 2007-106. The AESO only discovered the irrational outcome upon examining the POD charge for its refiling, as discussed above, and was of the view it should be addressed.

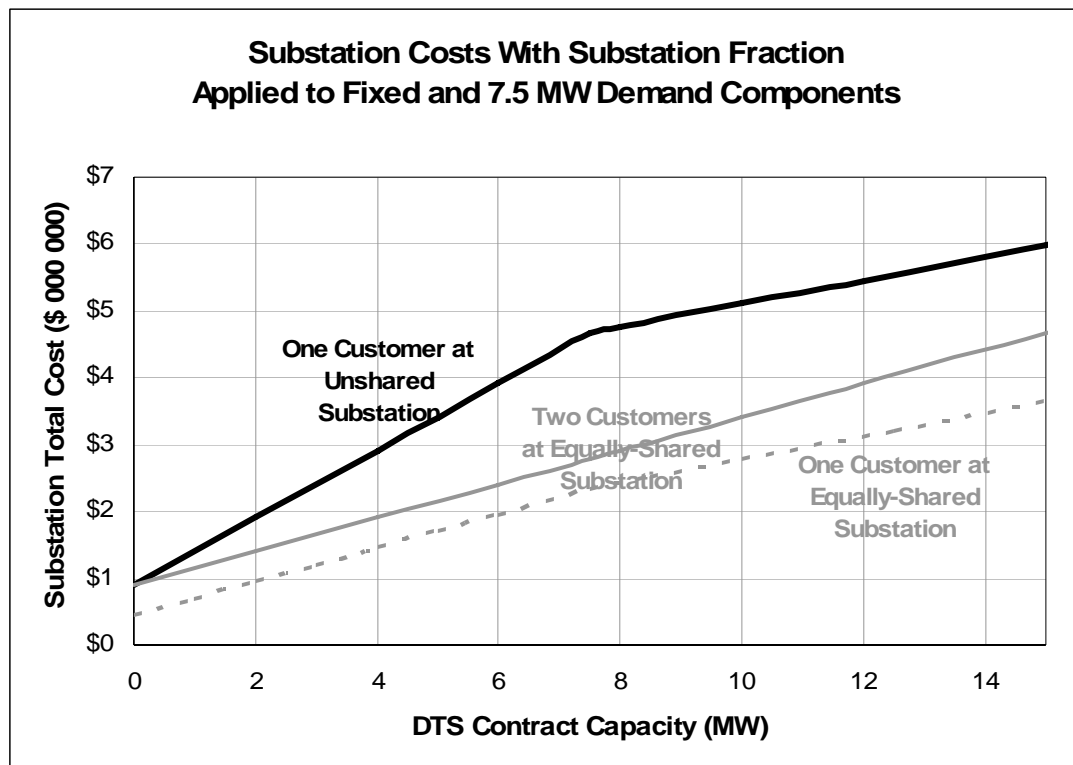
(f) During the comment process on the EUB’s proposed approach to the construct of the POD cost function in November 2007, the AESO simply continued the approach proposed in its GTA, namely, that “the customer and first demand components of the [proposed] cost function can be considered representative of the fixed cost of multiple-service substations” (AESO 2007 GTA, section 4, page 21). The AESO’s focus was on the underlying cost function rather than the details of the rate design.

Only after reviewing Decision 2007-106 in its entirety, including the fundamental differences in the underlying curves, differences in fixed cost components, and differences in breakpoint considerations as discussed in part (b) above, did the AESO conclude the substation fraction should not apply to the 7.5 MW demand component of the POD charge.

However, since its refiling, the AESO has continued to examine approaches to sharing the DTS POD charge, the maximum investment level, and the Primary Service Credit among multiple customers at a substation. The AESO suggests that apportioning all demand tier sizes between multiple customers at a substation provides a more satisfactory result than either applying the substation fraction to both the fixed and 7.5 MW demand component or to just the fixed component.

The AESO considers that the flaw in its application of the substation fraction to the 7.5 MW demand component of the POD charge is that the 7.5 MW are not shared between the customers. Rather, in the AESO’s application of the substation fraction to two customers at a substation, both customers are each allotted 7.5 MW of capacity and

Figure 001 (f)-1 Comparison of Total Substation Costs When Substation Fraction Is Applied to Fixed and First 7.5 MW Demand Component of Cost Function



the demand charge is reduced for both of them. If the two customers are of equal size, this results in a total of the first 15 MW of capacity at a shared substation (7.5 MW per customer) being charged at half-price. This is illustrated in Figure 001 (f)-1.

The alternative approach of apportioning all demand tier sizes between multiple customers at a substation results in each customers being allotted a share of 7.5 MW of capacity, and the full demand charge is applied to both of them. If the two customers are of equal size, this results in a total of the first 7.5 MW of capacity at a shared substation (3.75 MW per customer) being charged at full price. This is illustrated in Figure 001 (f)-2 above.

The application of the substation fraction to the tier sizes in the POD cost function is further illustrated in Table 001 (f)-3. The bolded line in the table shows that, when the substation fraction is applied to the fixed component and the demand tier sizes of the POD cost function, two 5 MW customers at a substation imply the total cost of the substation serving them (a total of 10 MW) is \$5.1 million, and the cost of a similar substation serving a single 10 MW customer is also \$5.1 million. Adding customers to a substation without increasing total substation capacity implies that total substation cost remains the same.

Figure 001 (f)-2 Comparison of Total Substation Costs When Substation Fraction Is Applied to Tier Sizes of Cost Function

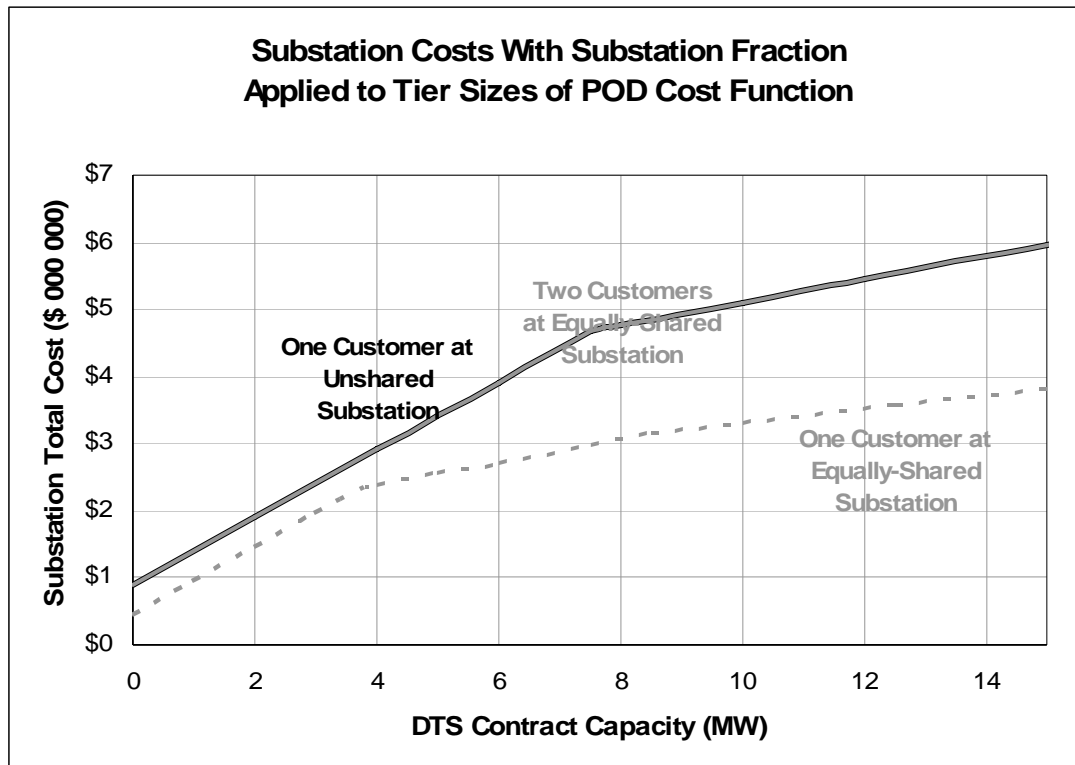


Table 001 (e)-2 Comparison of Total Substation Costs When Substation Fraction Is Applied to Just Fixed Component of Cost Function, \$ 000 000

Substation Capacity	One Customer at Substation		Two Equal Customers at Substation		
	Customer Capacity	Substation Cost	Per-Customer Capacity	Per-Customer Cost	Substation Total Cost
0 MW	0 MW	\$0.9	0 MW	\$0.4	\$0.9
2 MW	2 MW	\$1.9	1 MW	\$1.0	\$1.9
4 MW	4 MW	\$2.9	2 MW	\$1.5	\$2.9
6 MW	6 MW	\$3.9	3 MW	\$2.0	\$3.9
7.5 MW	8 MW	\$4.7	3.75 MW	\$2.3	\$4.7
8 MW	8 MW	\$4.8	4 MW	\$2.4	\$4.8
<b>10 MW</b>	<b>10 MW</b>	<b>\$5.1</b>	<b>5 MW</b>	<b>\$2.6</b>	<b>\$5.1</b>
12 MW	12 MW	\$5.4	6 MW	\$2.7	\$5.4
15 MW	15 MW	\$6.0	7.5 MW	\$3.0	\$6.0

The AESO therefore considers the approach of applying the substation fraction to the fixed component and the demand tier sizes of the POD cost function gives the most satisfactory result, compared to other approaches examined. The AESO accordingly recommends this approach be approved by the AUC for the DTS POD charge, the maximum investment level, and the Primary Service Credit in the AESO's refiled tariff.

Although additional costs may be incurred when additional customers are served by a substation as discussed in part (e) above, the AESO notes that single-customer and multiple-customer substations were included in the data on which the cost function was based, and the cost function was not differentiated between those substations. A brief review of the data suggests there is no consistent pattern of multiple-customer substations costing appreciably more than single-customer substations. As well, developing separate cost functions for single-customer and multiple-customer substations would add additional and, in the AESO's opinion, unnecessary complexity to the POD charge.

The AESO adds the further analysis leading to the above recommendation was only completed after the AESO had submitted its refiling. At the time of refiling, the AESO considered applying the substation fraction to just the fixed component of the POD charge provided the most rational result. However, the further analysis conducted since the refiling suggests that applying the substation fraction to the tier sizes provides an even more appropriate result.

(g) Not confirmed.

The total DTS billing capacity remained at 118,929.4 MW-months in the refiling, as provided in column A, line 1 of Schedule 5.9 of the AESO's 2007 GTA and in column A, line 2 of Schedule 5.10 of the refiling.

The actual DTS billing capacity up to 7.5 MW was also 36,796.1 MW-months in both the GTA and in the refiling. However, the AESO's 2007 GTA provided *equivalent* billing

capacity up to 7.5 MW in column A, line 2 of Schedule 5.9, with equivalent billing capacity explained in Note 1 on that schedule as “the sum over all DTS customers of the DTS Billing Capacity, to a maximum of 7.5 MW for each DTS customer, multiplied by the Substation Fraction for each DTS customer”. This approach was a simplified way in the rate calculations of accommodating a reduction in the demand charge for the first 7.5 MW of billing capacity for each customer at a shared substation, as discussed in part (f) above.

- (h) Please see attached Schedules Comm.AESO-001 (h)-A-5.1 through -A-5.13, which include equivalent billing capacity up to 7.5 MW as discussed in part (g) above.

Please also see the additional attached Schedules Comm.AESO-001 (h)-B-5.1 through -B-5.13, which provide rate calculations based on the AESO’s recommendation that the substation fraction be applied to tier sizes in the POD charge.

- (i) Please see attached Schedules Comm.AESO-001 (i)-A-1 through -A-10, which are based on applying the substation fraction to the fixed and 7.5 MW demand components of the POD charge.

Please also see the additional attached Schedules Comm.AESO-001 (i)-B-1 through -B-10, which provide the bill impact analysis based on the AESO’s recommendation that the substation fraction be applied to tier sizes in the POD charge.

The AESO has also found that six accounts were incorrectly attributed to customer groups in Appendix B of the AESO’s refiling on February 1, 2008. Five accounts that were identified as FortisAlberta, and one account that was identified as ATCO Electric, should have been identified as Direct Connect customers. That error has been corrected in the bill impact analyses provided in this information response. Although the per-POD amounts in the bill impact analyses do not change as a result of correction of this error, some of the averages for FortisAlberta, ATCO Electric, and Direct Connect customers are affected. In all cases, the impacts attributable to the correction are not considered material.

The AESO is unable to provide formulas in the bill impact analysis without disclosing actual historical billing determinants for individual customers, and the AESO consistently treats individual customer billing determinants as confidential information. The bill analysis was based on monthly customer-specific data for metered energy, metered demand, coincident demand, contract capacity, substation fraction, and average commodity price. The AESO considers that providing this quantity of detailed individual data, even when not identified by customer name or account, exceeds the usual standards of disclosure for billing information.

The AESO notes that the bill impact analysis provides average monthly metered energy, billing capacity, load factor, and substation fraction for each DTS service. These averages can be used to estimate average monthly bills, and therefore bill impacts, under each of the relevant rates. To assist in the calculation, the AESO has provided a bill estimation workbook as attached Schedule Comm.AESO-001 (i)-C. The workbook shows the detailed calculation for a DTS bill under each relevant rate, including formulas.

- (j) Updated rate schedules based on applying the substation fraction to the fixed and 7.5 MW demand components of the POD charge are provided in Attachment Comm.AESO-001 (j)-A. The affected rate schedules are:
- the DTS rate itself, including reductions to the bulk system and local system charges reflecting the allocation of an updated Primary Service Credit revenue offset;
  - the Fort Nelson FTS rate, which reflects the updated DTS bulk system and local system charges noted above;
  - the Primary Service Credit, which is derived from the updated DTS POD charge and results in an updated Primary Service Credit revenue offset; and
  - the Demand Opportunity Service 1 Hour and Term rates, which are derived from the DTS rate and include reductions to charges reflecting the updated interconnection charges in the DTS rate.

Attachment Comm.AESO-001 (j)-A also provides an updated Determination of Customer Contribution Article 9.6 from the terms and conditions of service, reflecting the updated application of the substation fraction in determining the maximum local investment.

Updated DTS, FTS, PSC, DOS 1 Hour, and DOS Term rate schedules, based on the AESO's recommendation that the substation fraction be applied to tier sizes in the POD charge, are also provided in Attachment Comm.AESO-001 (j)-B. That attachment similarly includes a recommended Determination of Customer Contribution Article 9.6.

**Title:** DTS POD Rate Design

**Reference:**

- AESO 2007 General Tariff Application Refiling, s. 7, page 2 of 2
- DUC.AESO-002 (b-c)

**Preamble:** The DUC seek clarity on why the substation fraction is not proposed to apply to the first 7.5 MW of the DTS Rate POD charge.

In the refiling application the AESO stated:

The AESO notes that, in the POD charge developed in response to this direction, the substation fraction continues to apply to the customer (\$/month) component and not to any of the demand (\$/MW) components of the charge. This is consistent with the POD charge in the current DTS rate, but **differs from the POD charge proposed in the AESO's GTA where the substation fraction applied to both the customer component and the first (7.5 MW) demand component.**

...

In the AESO's 2007 GTA, the **AESO considered that "the customer and first demand components of the [proposed] cost function can be considered representative of the fixed cost of multiple-service substations"** (AESO 2007 GTA, section 4, page 21). The same approach was assumed in the AESO's responses to information requests submitted on November 19, 2007, as part of the comment process on the EUB's proposed approach to the construct of the POD cost function.

However, Direction 5 of **Decision 2007-106 requires the AESO to implement a POD cost function that is significantly different from that proposed in the AESO's GTA.** That POD cost function is based on a continuous power curve, reflective of significant economies of scale with increasing capacity, and considered "more robust and desirable" by the EUB (Decision 2007-106, page 51). The customer (fixed) component of the directed cost function is \$0.894 million, and consistent with the clarification provided in the EUB's letter in the AESO's 2005-2006 GTA, the **AESO has apportioned that customer component (and no demand components) amongst the customers served by a particular substation through the application of the substation fraction.**

In response to DUC-AESO-002 (b-c) the AESO noted that the substation fraction should apply to the first POD demand charge (0 to 7.5 MW):

$$\begin{aligned} \text{Recommended Cost} &= \$0.947 \text{ million} \\ &+ (\$0.621 \text{ million/MW} \times \text{first 7.5 MW of DTS Capacity}) \\ &+ (\$0.154 \text{ million/MW} \times \text{DTS Capacity above 7.5 MW}) \end{aligned}$$

The first two components (the smaller fixed component and the “first 7.5 MW” component) effectively replace the single-line fixed component. These two components should both be adjusted by the substation fraction for the same reasons discussed above regarding sharing the single-line fixed component between multiple services at a substation.

Similarly, the third component (the “above 7.5 MW” component) remains the same as the demand component in the single-line equation, and for the reasons discussed above should not be adjusted by the substation fraction.

**Request:**

- (a) Please provide any references to EUB/AUC documents that suggest that the substation fraction should not apply to the 0 to 7.5 MW POD charge.
- (b) Please reconcile the response provided in DUC-AESO-002 (b-c) with the proposed refiled DTS rate where the substation fraction is proposed not to apply to the 0 to 7.5 MW POD charge.
- (c) Please explain how the AUC’s “POD cost function that is significantly different from that proposed in the AESO’s GTA” justifies the elimination of the substation fraction from the 0 to 7.5 MW POD charge.

**Response:**

- (a) Please refer to information response Comm.AESO-001 (b).
- (b-c) Please refer to information response Comm.AESO-001 (e).

**Title:** Implementation of AESO 2007 Tariff

**Reference:** AESO Letter to AUC Dated February 28, 2008

**Preamble:** The DUC seek to clarify the AESO's position with respect to the implementation date for the investment policy. In its letter the AESO stated:

The purpose of this letter is to request clarification with respect to the implementation date of certain aspects of the AESO's 2007 Tariff.

On December 21, 2007, the Alberta Energy and Utilities Board (EUB, now AUC) issued Decision 2007-106. Among other things, the Decision approved the maximum investment function that is to be part of the final Terms and Conditions of the AESO Tariff (page 98), and also ordered the AESO to refile its tariff by February 1, 2008. The tariff in its entirety was not approved in Decision 2007 106.

On the basis that the maximum investment function has been approved, some stakeholders have requested the AESO to consider its effective date to be that of the Decision. The AESO has taken the view that only once the entire tariff is approved, can any individual element of it be effective. Given there is some room for interpretation in this regard, the AESO seeks confirmation from the EUB (or AUC) with respect to its intended implementation date of the maximum investment function.

**Request:**

Please explain the basis for the AESO's view that "only once the entire tariff is approved, can any individual element of it be effective" in light of the clear directions the AUC provided in Decision 2007-1006 with respect to the investment policy.

**Response:**

The AESO's view is based on traditional practice in Alberta. In the AESO's experience, tariffs are ordinarily approved as a whole with a specific effective date, and only rarely has one part of a tariff been approved in advance of the balance of a tariff. The AESO understands the general theory behind the practice reflects the tariff having many parts that work together as a whole, and implementing any part of it in the absence of the related changes is therefore inconsistent (and potentially unfair). For example, Decision 2007-106 achieved significant consistency between the POD charge in the DTS rate, the DTS contribution policy, and the Primary Service Credit. Implementing the contribution policy before those other components will have the effect of providing investment at new services on a basis that is inconsistent with the DTS POD

charge and the Primary Service Credit. Customers could therefore receive investment inconsistent with the recovery of that investment in the rates which they are charged, for the period until the tariff becomes effective in its entirety.

As well, in this particular case, there is the practical consideration that the maximum investment function was approved as noted in Decision 2007-106, but the implementation of that function in the AESO's tariff has not yet received approval and has not had an effective date identified for it. More specifically, the maximum investment function identified investment amounts that would be available to a single DTS customer at a TFO-owned substation signing a contract of maximum term. Final approval has not yet been provided for the reduction of those maximum amounts to reflect sharing of costs between multiple customers at a substation, for shorter contract terms, or for customer ownership of transformation. With respect to the last point, Decision 2007-106 provided no specific approval or direction relating to maximum investment levels available to Primary Service Credit customers who own their own transformation, although the AESO provided information regarding relevant investment levels in its response to Direction 10 on the Primary Service Credit rate itself.

Notwithstanding the above, the AESO understands some customers are considering delaying construction or otherwise deferring interconnection until the new contribution policy becomes effective. Such delays and schedule changes create inefficiencies for the customers, for the TFOs constructing the interconnection facilities, and for the AESO. As early implementation of the contribution policy may avoid such delays and inefficiencies, the AESO considered it reasonable to request the AUC provide clarification with respect to the implementation date of the contribution policy.



**Reference:** Section 5, Schedule 2.0

**Preamble:** The revised rates will be applied to charges incurred in 2008. EnCana understands that the rate calculations in Section 5 are based on forecasts of 2007 costs and billing determinants. EnCana wishes to explore the difference between the assumptions underlying the 2007 rates and the forecast of 2008 costs and rates.

**Request:**

- (a) Please provide an estimate or forecast of the differences between the AESO's costs and revenues, and hence the magnitude of Rider C, for the first six months of 2008 assuming the Commission approves the implementation of new base rates effective July 1 or for that period of time which the AESO believes the existing rates will continue to be in effect.
- (b) Please provide a summary of the forecasted difference between AESO's costs and revenue, and hence the magnitude of Rider C, for the rest of 2008, assuming the Commission approves the rates proposed by the AESO in this refiling.

**Response:**

- (a-b) Please refer to attached Schedule EnCana.AESO-001 (a-b).

**Reference:** Section 5.0

**Preamble:** The revised rates will be applied to charges incurred in 2008. EnCana understands that the rate calculations in Section 5 are based on forecasts of 2007 costs and billing determinants. EnCana wishes to explore the difference between the assumptions underlying the 2007 rates and the forecast of 2008 costs and rates.

**Request:**

- (a) Please revise Schedule 2.0 from Section 5.0 by adding a column for each of
  - (i) the 2007 estimated final costs (for all cost categories),
  - (ii) the AESO's forecast of 2008 costs.
- (b) Please provide a forecast of the billing determinants for 2008.
- (c) Please provide a forecast of the base rates using the 2008 forecasted costs and billing determinants.
- (d) Please provide a summary of the forecasted difference between AESO's costs and revenue, and hence the magnitude of Rider C, for the period after the Commission approves the implementation of new rates using the rates as calculated in the response to question c). (Please use the same period assumed under question 1b.)

**Response:**

Please note that all values provided in this response are based on a preliminary estimate of costs and billing determinants for 2008. Final forecast values, if filed at a later date, may differ to some extent from these preliminary estimates.

- (a) Please refer to attached Schedule EnCana.AESO-002 (a).
- (b) Please refer to attached Schedule EnCana.AESO-002 (b).
- (c) Please refer to attached Schedule EnCana.AESO-002 (c).
- (d) Please refer to attached Schedule EnCana.AESO-002 (d).

**Reference:** Section 5.0

**Preamble:** The revised rates will be applied to charges incurred in 2008. EnCana understands that the rate calculations in Section 5 are based on forecasts of 2007 costs and billing determinants. EnCana wishes to explore the difference between the assumptions underlying the 2007 rates and the forecast of 2008 costs and rates.

**Request:**

- (a) Please provide the AESO's plans for future rate applications. Specifically applications to approve the forecasted revenue requirement and base rates.
- (b) How long does the AESO expect the rates as approved in this refiling to be in effect?
- (c) Would the timing of a new application for the implementation of new base rates be determined by the magnitude of Rider C?
- (d) Would the AESO consider filing an application for 2009 rates in September or October of 2008?

**Response:**

- (a) The AESO expects rates resulting from its 2007 GTA to become effective in mid-2008. The AESO then anticipates conducting stakeholder consultation before preparing and filing its next comprehensive general tariff application, which will therefore likely be filed in mid-2009 using 2010 as the forecast test year.
- (b) The AESO expects rates resulting from its 2010 tariff application would be effective in mid-2010. Rates approved as a result of the current refiling could therefore remain in place until that time, subject to considerations discussed in part (d) below.
- (c) The AESO considers various factors in deciding the timing of a tariff application, including how well revenue from different rate components matches costs. The magnitude of Rider C on its own would likely not be a primary driver for a rate application, but would be a consideration.
- (d) Yes, the AESO is considering filing a rates "update" in late 2008 that would continue the rate calculation methodology approved in this refiling, but use forecast costs and billing determinants for 2009.

**Reference:** Section 6.0 – Proposed Tariff – Article 11; Decision 2008-014

**Preamble:** The version of Article 11 included in the proposed Tariff refiling is not consistent with the Article 11 as approved by the AUC in Decision 2008-014.

**Request:**

- (a) Please provide a copy of Article 11 consistent with that approved in Decision 2008-014 for inclusion in the proposed Tariff.
- (b) Please confirm that the AESO is seeking approval at this time of the proposed Tariff with the inclusion of Article 11 as approved in Decision 2008-014. If not, please explain.

**Response:**

- (a) Article 11 as filed in the AESO's Ancillary Services Article 11 Negotiated Settlement (Application 1549401) was approved in Decision 2008-014 to be effective February 13, 2008. The approved and effective version of Article 11 was accordingly incorporated into the AESO's current tariff and posted on the AESO web site as part of the AESO's terms and conditions of service on February 13, 2008. Please see Attachment EnCana.AESO-004 (a) which is Article 11 as effective in the AESO's current tariff.

The same Article 11 will be incorporated into the AESO's tariff when it is approved in due course as part of the current refiling process or any subsequent refiling process that may take place.

- (b) The AESO included the following on page 2 in section 2.3 of its Refiling:

Finally, the AESO notes that it has filed Application No. 1549401 requesting approval of a revised Article 11 developed through a negotiated settlement process. Article 11 as included in the terms and conditions in this refiling will be updated as necessary at such time as the AUC approves the Article 11 application.

As a final version of Article 11 has been approved and is effective as a result of Decision 2008-014, and as no changes to Article 11 were directed in Decision 2007-106 nor identified subsequent to Decision 2008-014 being issued, the AESO is not seeking any further approval with respect to Article 11. If the AESO's tariff is subject to a second refiling, the approved version of Article 11 will be included in that refiling. In any case, the approved version of Article 11 will be incorporated into the AESO's tariff when the balance of the tariff is approved in due course as a result of the current proceeding.