



Topic: Rate Calculations

Reference: 2010-03-04 AESO 2010 ISO Tariff - Appendix C - Transmission OM Cost Study.pdf

Preamble: IPCAA wishes to examine the impact of the Transmission O&M Cost Study on the AESO rate design.

Request:

Please provide a version of the Transmission OM Cost Workbook with AE's isolated generation costs functionalized as in the O&M Cost Study but classified as demand rather than energy.

Response:

Please refer to Attachment IPCAA.AESO-001.

Topic: Rate Calculations

Reference: 2010-03-04 AESO 2010 ISO Tariff - Section 5 - Rate Calculations.xls 2010-03-04 AESO 2010 ISO Tariff - Appendix D - Transmission OM Cost Workbook.xl

Preamble: IPCAA wishes to understand how the Transmission O&M Cost Study was incorporated into the AESO rate design.

Request:

- (a) In Table 5-1, the values in column A, rows 2 to 5 set out the breakdown of wires costs as between bulk, local and POD functions. The breakdown percentage calculates as follows:

A				
Line No.	Description	Updated Forecast \$ 000 000	Calculated Percentage	Sum 4.0
1	Wires			
2	Bulk System	\$225.2	34.73%	34.40%
3	Local System	143.4	22.11%	21.70%
4	Point of Delivery	279.9	43.17%	43.90%
5	Total Wires	\$648.4	100.00%	100.00%

Please reconcile these percentages with the percentages shown at the bottom of Table Sum 4.0 (row 53 of the spreadsheet) in the Transmission O&M Cost Study. Why do they differ?

- (b) Please explain how isolated generation costs are reflected in column A (Forecast total wires costs of \$648.4 million) quoted above.
- (c) Please indicate the level of isolated generation costs reflected in the Forecast total wires costs of \$648.4 million.
- (d) Please indicate the level of isolated generation costs reflected in the Transmission O&M Cost Study. Please explain the differences in O&M costs reflected in the AESO Forecast total wires costs and the Transmission O&M Cost Study.

Response:

- (a) Please refer to information response DUC.AESO-009 (c). The functionalized wires cost in Table 5-1 reflects the isolated generation credit being apportioned to the local system and POD functions.

- (b) Isolated generation costs are included in ATCO Electric's wires cost of \$246.3 million, which is part of the total wires cost of \$648.4 million that is functionalized to bulk system, local system, and POD functions in accordance with the findings from the *Transmission O&M Cost Study* filed as Appendix C to the application.

Isolated generation costs are offset by the isolated generation credit of \$4.4 million as discussed in section 2.2 (page 16, paragraph 60) of the application. The isolated generation credit is apportioned to the local system and POD functions in the same proportion that isolated generation costs were apportioned to those functions in the *Transmission O&M Cost Study*.

- (c) The \$246.3 million 2010 forecast cost for ATCO Electric TFO was approved in Commission Decision 2010-056 on ATCO Electric's 2009-2010 General Tariff Application Compliance Filing. That filing included a total of \$16.4 million for transmission-related isolated generation in 2010, comprised of the following amounts:
- \$9.6 million for fuel cost (from line 8 of Revised Schedule 3-1), and
 - \$6.8 million for isolated generation operation and maintenance (from line 16 of Revised Schedule 5-1).

As noted in part (b) above, these costs are offset by the isolated generation credit of \$4.4 million as discussed in section 2.2 (page 16, paragraph 60) of the 2010 tariff application. The net cost related to isolated generation included in the wires cost in the 2010 ISO tariff is therefore \$12.0 million.

- (d) The following amounts were included in the *Transmission O&M Cost Study* for isolated generation, as provided on sheet "AT Sch 5.1" in the *Transmission O&M Cost Workbook*:

Cost Component	Isolated Generation Cost, \$ 000 000			
	2006	2007	2008	2009
Fuel	\$8.4	\$8.7	\$8.2	\$9.3
Operation and Maintenance	4.2	4.8	5.9	6.5
Total	\$12.6	\$13.5	\$14.1	\$15.8

The AESO considers these costs to be comparable to the \$16.4 million of isolated generation costs included in the forecast total wires cost, given that the forecast cost is for 2010 and the 2006-2009 costs show a trend of year-over-year increases. As well, costs in the *Transmission O&M Study* were used to develop percentage functionalization and classification factors which could then be applied to a forecast year's costs, and therefore do not have to match the forecast costs precisely.

Topic: Rate Calculations

Reference: 2010-03-04 AESO 2010 ISO Tariff - Section 5 - Rate Calculations.xls

Preamble: IPCAA wishes to understand how AESO's calculation with respect to classification to rate components.

Request:

- (a) In Table 5-3, the costs for each function are classified to rate components. The breakdown percentage for Non-coincident demand calculates as follows:

Line No.	Description	A	B	C	Column C as % of A
		DTS Amount [Table 4-1] \$ 000 000	Non-Coincident Dem'd Allocator %	Amount \$ 000 000	
1	Wires				
2	Bulk System	\$225.2	-	\$-	
3	Local System	143.4	78.51%	113.7	79.32%
4	Point of Delivery	279.9	82.75%	234.0	83.60%
5	Total Wires	\$648.4	53.6%	\$347.7	

Please explain why column B indicates 78.51% of local system classified to non-coincident demand but the actual percentage is 79.32%. Similarly, please explain why the table appears to indicate 82.75% of POD costs are classified as non-coincident demand but the actual percentage is 83.60%.

- (b) Please confirm that the value of 78.51% is derived from the Transmission O&M Cost Study, particularly it can be derived from Table Sum 4.0 by dividing the Local System Demand related portion of 17.04% (line 50) by the total Local System value of 21.70% (line 53).
- (c) Please explain how the POD value of 82.75% is derived, specifically reconciling the value to Table Sum 4.0 of the Transmission O&M Cost Study.

Response:

- (a) Please refer to information responses DUC.AESO-009 (c) and (d). The functionalized wires cost in Table 5-1 reflects the isolated generation credit being apportioned to the local system and POD functions, while the classification percentages ("Allocators") in Table 5-1 reflect the isolated generation credit being classified wholly as usage-related.

- (b) Confirmed. The value in the request was based on the *Transmission O&M Cost Workbook* filed as Appendix D of the application. A revised Appendix D workbook has been submitted with these information responses, as well as revised section 5 rate calculations. The value in the revised rate calculations is based on the revised Appendix D workbook.

- (c) The classification of non-coincident demand-related and customer-related POD costs based on the *Transmission O&M Cost Study* was replaced with the classification from the more detailed POD cost function analysis, as discussed in section 4.3.1 (pages 32-34) of the application. The derivation of the classification is provided on line 9 of Table 5-4 in section 5 of the application. Please refer to information response IPCAA.AESO-007 (b) for additional information.

Topic: Rate Calculations

Reference: 2010-03-04 AESO 2010 ISO Tariff - Section 5 - Rate Calculations.xls

Preamble: IPCAA wishes to understand how AESO's calculation with respect to classification to rate components.

Request:

- (a) In Table 5-3, the costs for each function are classified to rate components. The breakdown percentage for flat usage calculates as follows:

Line No.	Description	A	F	G	Column G as % of A
		DTS Amount [Table 4-1] \$ 000 000	Flat Usage Allocator %	Flat Usage Amount \$ 000 000	
1	Wires				
2	Bulk System	\$225.2	18.50%	\$41.7	18.50%
3	Local System	143.4	21.49%	29.6	20.68%
4	Point of Delivery	279.9	6.22%	14.7	5.25%
5	Total Wires	\$648.4	13.3%	\$347.7	

Please explain why column F indicates 21.49% of local system classified to flat usage but the actual percentage is 20.68%. Similarly, please explain why the table appears to indicate 6.22% of POD costs are classified as flat usage but the actual percentage is 5.25%.

- (b) Please confirm that the value of 21.49% is derived from the Transmission O&M Cost Study, particularly it can be derived from Table Sum 4.0 by dividing the Local System Demand related portion of 4.66% (line 51) by the total Local System value of 21.70% (line 53).
- (c) Please confirm that the value of 6.22% is derived from the Transmission O&M Cost Study, particularly it can be derived from Table Sum 4.0 by dividing the Local System Demand related portion of 2.73% (line 51) by the total Local System value of 43.90% (line 53).

Response:

- (a) Please refer to information response IPCAA.AESO-003 (a).

- (b) Confirmed. Please refer to information response IPCAA.AESO-003 (b) for additional information.
- (c) Confirmed. Please refer to information response IPCAA.AESO-003 (b) for additional information.



Topic: Rate Calculations

Reference: 2010-03-04 AESO 2010 ISO Tariff - Section 5 - Rate Calculations.xls

Preamble: IPCAA wishes to understand how AESO's calculation with respect to classification to rate components.

Request:

- (a) In Table 5-3, the costs for each function are classified to rate components. The breakdown percentage for customer calculates as follows:

Line No.	Description	A DTS Amount [Table 4-1] \$ 000 000	Customer		Column K as % of A
			J Allocator %	K Amount \$ 000 000	
1	Wires				
2	Bulk System	\$225.2	-	-	-
3	Local System	143.4	-	-	-
4	Point of Delivery	279.9	11.04%	31.2	11.15
5	Total Wires	\$648.4	13.3%	\$86.0	

Please explain why column J indicates 11.04% of local system classified to customer but the actual percentage is 11.15%.

- (b) Please confirm that the value of 11.04% is derived in Table 5-4.

Response:

- (a) Please refer to information responses IPCAA.AESO-003 (a) and (c).
- (b) Confirmed. Please refer to information response IPCAA.AESO-003 (b) for additional information.

Topic: Rate Calculations

Reference: 2010-03-04 AESO 2010 ISO Tariff - Section 5 - Rate Calculations.xls

Preamble: In IPCAA-AESO-2 through IPCAA-AESO-5, IPCAA requested clarification of apparent inconsistencies in the AESO calculations.

Request:

- (a) If the AESO finds any inconsistencies in their rate calculation spreadsheets, please provide an updated rate calculation workbook (Tables 5-1 through 5-14).
- (b) Please provide an updated rate calculation workbook (Tables 5-1 through 5-14) incorporating the Transmission O&M Cost Study results requested in IPCAA-AESO-1, classifying isolated generation costs as demand related.
- (c) Please provide an updated rate calculation workbook (Tables 5-1 through 5-14) that excludes the Transmission O&M Cost Study (i.e. recovers the 2010 revenue requirement and reflects the POD cost update but reflects no re-functionalization or re-classification arising from the Transmission O&M Cost Study).

Response:

- (a) Please refer to the revised section 5 rate calculations submitted with these information responses.
- (b) Please see Attachment IPCAA.AESO-006 (b).
- (c) Please see Attachment IPCAA.AESO-006 (c).

Topic: DTS Rate Design

Reference: Section 4.3.1 Transmission Point of Delivery Cost Classification 2010-03-04
AESO 2010 ISO Tariff - Section 5 - Rate Calculations.xls

Preamble: IPCAA wishes to examine the linkage between the Transmission O&M Cost Study and the DTS Tariff Design

Request:

- (a) Please confirm that Table 5-4 classifies POD costs to the customer components and the demand tiers based on the factors derived from the POD cost function after subtracting a percentage classified to usage (energy) [6.22%, column F, line 9] where the percentage classified to usage (energy) is derived from the Transmission O&M Cost Study.
- (b) Please explain why it is appropriate to incorporate the energy related component of POD costs from the Transmission O&M Cost Study but not the customer related cost?

Response:

- (a) Confirmed.
- (b) The customer-related component of POD costs from the *Transmission O&M Cost Study* does not reflect the significant economies of scale that were an important consideration in prior decision on the structure of the Rate DTS POD charge. In particular, in Decision 2007-106 on the AESO's 2007 tariff application, the Alberta Energy and Utilities Board found:
 - *the impact of economies of scale on POD costs is significant as capacity increases and is to be reflected in the POD cost function and design of the POD charge;...*
 - *a non-linear function best describes the of POD cost economies of scale [page 38]*

The Board further concluded:

As a result, the Board considers that for all but exceptionally low values of DTS contract capacity, the power function based on the POD cost function developed by Board staff provides a cost estimate that is both reasonable and similar to the cost estimates produced by functional forms that include a minimum intercept. [page 55]

Consistent with these findings with respect to economies of scale and the appropriateness of a power function as the basis for the POD charge, the AESO has

continued to base the classification of demand- and customer-related costs on the power function methodology approved in Decision 2007-106.

Topic: PSC

Reference: Section 4.9 Primary Service Credit Rate PSC

Preamble: The AESO states:

Under the AESO's current tariff, if a connection does not include conventional TFO-owned transformation facilities, the market participant may choose whether to receive the lower rate and lower investment level applicable under Rate PSC or whether to receive the higher rate and higher investment level applicable under Rate DTS.

Request:

- (a) The AESO describing circumstances where the connections do not include conventional TFO-owned transformation facilities. Does it follow that customers who choose the lower investment level and lower rate pay a higher contribution than customers who select the higher investment level and higher rate? If this is the case, is it not the case that the customer has, in effect, the option to amortize a portion of his/her customer contribution?
- (b) If it is the case that the customer has, in effect, been provided an option to amortize his/her contribution why does the AESO oppose this when elsewhere in the application the AESO is proposing Rider I?

Response:

- (a) Yes, under the AESO's current tariff market participants who choose the lower investment level and lower rate pay a higher contribution than those who choose the higher investment level and higher rate. This could be considered an amortization option, with the cost of the amortization averaged over all services under Rate DTS.
- (b) The AESO considers that the option to amortize construction contributions through Rider I results in a market participant paying the specific capital-related costs attributable to a service, rather than the average costs as under Rate DTS. However, the AESO acknowledges that there are similarities between the repayment of investment through Rate DTS and the repayment of a construction contribution under Rider I. The AESO suggests that the potential to amortize a contribution under Rider I offsets any potential inconvenience a market participant may experience by the removal of the option to elect the higher Rate DTS investment level.

As discussed in information response DUC.AESO-005 (b), the removal of the option to elect the higher Rate DTS investment level is more a matter of consistency with the principles underlying the AESO's tariff than with matters of specific harm or benefit.

Topic: Rider I

Reference: Section 4.16 Amortized Construction Contribution Rider I

Preamble: IPCAA wishes to understand the mechanics of the proposed Rider I.

Request:

- (a) Please explain how Rider I payments made by customers would be treated. Would such payments be reflected as a reduction in AESO revenue requirement or would they be passed on to the TFOs? Is some other treatment proposed? If so, please explain.
- (b) If Rider I payments are retained by the AESO, would they be treated as an offset to TFO wires costs?
- (c) If Rider I payments are passed to the TFOs, would the AESO expect that they would be recorded as customer contribution in the year they are received by the TFO? If such treatment were in place, would the AESO expect that the TFO would forecast receipt of Rider I funds?
- (d) Please provide the level of customer contributions over the last five years separated into generator, load and dual use customers. If this specific breakdown cannot be provided please provide any generator/load split that is available.
- (e) Please provide an explanation as to why the DTS and STS customers are grouped into a common pool for risk mitigation and why separate pools were not considered.
- (f) Please provide an explanation as to why an insurance backstop was not considered as an alternative to the mutualized risk mechanism that is proposed. And did the AESO consider the consequences of an early default on the proposed mechanism if there is a shortfall in the collected risk premiums?

Response:

- (a-b) As discussed in section 4.16 (page 62, paragraph 314) of the application, the AESO proposes to treat Rider I payments as an offset to the TFO tariff costs recovered from market participants. The Rider I payments would therefore be treated like other tariff revenue offsets arising from the AESO's rates and riders, and would reduce the AESO's revenue requirement that would otherwise need to be recovered through Rate DTS. The Rider I payments would not be passed on directly to the TFOs.

The AESO did not include an estimate of Rider I payments in this application due to uncertainty with respect to the amount of such payments. However, any payments received would be included in the AESO's deferral account riders and reconciliations and would accordingly reduce TFO tariff costs recovered from market participants.

- (c) The AESO does not expect TFOs to record Rider I payments as construction contributions in the year they are received, nor to forecast receipt of Rider I payments.
- (d) Based on available information, the AESO has compiled contribution amounts for completed and applied-for connection projects with in-service dates from 2004 (actual) to 2011 (requested). The requested breakdown of contributions is as follows:

Category	Construction Contributions 2004-2011	
	\$ 000 000	%
Generator (STS Only)	\$23.9	9.7%
Load (DTS Only)	217.4	88.5%
Dual-Use (STS and DTS at Same Site)	4.3	1.8%
Total	\$245.6	100.0%

- Notes: 1. A generator (STS only) site frequently includes a small contract capacity under Rate DTS but would not usually be considered a dual-use site.
2. A load (DTS only) site may include onsite generation for emergency use when normal transmission service is interrupted or unavailable.
3. A dual-use site includes a substantial load requirement with on-site generation intended to normally supply that load, either fully or partially.

These amounts do not include generating unit owner's contributions ("system contributions" in the AESO's current tariff) that have been required since 2006.

- (e) The AESO was unable to establish any factors that would differentiate the risk of default between an amortized payment option provided to market participants under Rate DTS and one provided under Rate STS. Without differentiating factors, it did not seem reasonable to establish separate rider "pools". As well, the risk of default appears very low, and would be more difficult to administer over two separate and smaller pools rather than over a single larger pool.
- (f) In general, the AESO understands that an insurance arrangement would require quantification of the risk of default before being offered, or would otherwise include a larger risk premium to protect the insurer. As discussed in section 4.16 (page 61, paragraph 309) of the application, the AESO was unable to quantify the risk that a project requiring system access service would be abandoned due to the availability of Rider I. The AESO concluded that the Rider I approach proposed in the application would be simpler and probably less costly than an insurance arrangement. The AESO also considered that the more complex and expensive an amortized payment option became, the fewer market participants would elect to utilize it and the more likely that the concerns which prompted the Rider I proposal would not be addressed.

Topic: Determination of Maximum Investment Levels

Reference: Section 6.11.3 Facilities in Excess of Good Electric Industry Practice
Section 6.11.7 Determination of Local Investment
2010-03-04 AESO 2010 ISO Tariff - Appendix F - POD Cost Function Update.pdf
2010-03-04 AESO 2010 ISO Tariff - Appendix G - POD Cost Function
Workbook.xls

Preamble: IPCAA wishes to examine the AESO's criteria in respect of local investment.

Request:

- (a) Please confirm that 15 of 64 greenfield projects had costs that were in excess of "standard facilities".
- (b) Please confirm that these 15 projects had, on average, 18% of their costs considered in excess of "standard facilities".
- (c) Please confirm that the POD cost function used to derive the POD components of the DTS tariff (Table 5-4 POD Cost Function and POD Cost Classifications) was based on total costs, not standard costs. Please explain why the total cost function was the appropriate cost function from which to derive the POD components of the DTS tariff.

Response:

- (a) Confirmed.
- (b) Confirmed.
- (c) The AESO considers it is important to maintain alignment between the POD cost function used to develop the POD charge in Rate DTS and the function used to develop the maximum investment level in the AESO's tariff. However, with respect to the POD charge, this alignment primarily concerns the "shape" of the cost function. The shape of the cost function determines the proportions of the POD charge components relative to each other, while the level of the POD charge components is determined by the POD-related revenue requirement that is to be recovered.

The shape of the POD cost function is very similar whether based on standard facilities costs or total costs. Please refer to information response CCA.AESO-016 (c) for a comparison of POD charges resulting from a POD cost function based on standard facilities compared to the proposed approach based on total facilities. As discussed on page 16 of the *POD Cost Function Update* filed as Appendix F to the application, the POD charge components varied by no more than $\pm 1\%$ between the two approaches.

Topic: DTS Rate Design

Reference: Section 6.11.7 Determination of Local Investment

Preamble: IPCAA wishes to examine the linkage between DTS POD rate components and the maximum investment level for each component.

Request:

- (a) Please provide a table (similar to Table 5-11) comparing the POD components (lines 7 through 12) of the DTS tariff for each of the 2007, 2009 and 2010 proposed DTS tariffs.
- (b) Please provide the percentage increase in each POD DTS tariff component (above) in respect of POD charges since 2007 for each of the 2009 and the 2010 proposed DTS tariffs.
- (c) Please provide a table comparing the maximum investment level in respect of each POD component for each of the 2007, 2009 and 2010 proposed DTS tariffs.
- (d) Please provide a comparison of the percentage increase in the maximum investment level in respect of each POD component since 2007 for each of the 2009 and the 2010 proposed DTS tariffs.
- (e) Please explain any circumstances where the DTS rate component and the investment level have not increased the same percentage.

Response:

- (a-d) Please see Attachment IPCAA.AESO-011 (a-d).
- (e) Although based on the same POD cost function, POD charges and investment level represent different quantities that are not generally expected to increase by the same amount.

POD charges relate to embedded costs, while investment levels relate to incremental costs. POD charges relate to capital, operating, maintenance, and administrative costs of TFOs and the AESO. Investment levels relate only to the capital costs of TFO-owned facilities used for connection projects to provide new or expanded system access service to market participants. The different nature of the costs to which POD charges and investment level relate will give rise to different rates of increase for the two quantities.

As well, the AESO's 2009 rates update application did not update the investment level in the tariff, and resulted only in an increase to rates.

Topic: Prepaid O&M

Reference: Section 6.11.8 Operations and Maintenance

Preamble: IPCAA wishes to understand the implication of applying Prepaid O&M to costs in excess of maximum investment rather than for only optional facilities.

Request:

- (a) Does the AESO agree that absent the definition of standard facilities, there will be no distinction between contributions for “optional” facilities (or facilities in excess of “standard” facilities) and contributions for “standard” facilities that are significantly more costly than average?
- (b) Please list the major factors that, in the AESO’s opinion, generally cause the interconnection costs of a customer to be higher than others.
- (c) For each factor identified in (b), please discuss the implications of the cost factor in terms of contributing to higher O&M costs.

Response:

- (a) Confirmed.
- (b) The AESO considers that the following factors can cause higher costs for some connection projects compared to others:
 - (i) substation capacity, including transformer number and size;
 - (ii) substation configuration, including primary and secondary voltages, bus type, and number of breakers;
 - (iii) the connection to the existing system, including type (tap or in-out);
 - (iv) radial line, if required, including length, voltage, type (wood pole or steel tower), and configuration (single radial or double radial);
 - (v) communication and protection equipment, including enhancements at existing substations, if required;
 - (vi) general complexity of the project, including considerations such as proximity to or interference with other substations, lines, and facilities;
 - (vii) special considerations such as restoration time or motor starting;
 - (viii) varying geography and construction conditions;
 - (ix) environmental impact considerations; and
 - (x) other factors unique to individual projects, such as line moves or burials.
- (c) Most of the factors listed in (b) would contribute to higher O&M costs for the connection. In general, the factors listed all result in larger, additional, or more complex facilities being constructed, which generally result in higher O&M costs. Some, such as additional or larger transformers or long radial lines, clearly result in additional facilities that would

contribute to higher O&M costs. Others, such as more expensive communications equipment or increased project complexity, may contribute to higher O&M costs but less directly.

The factors which may not contribute to higher O&M costs would be those which primarily cause increased labour costs during construction, such as varying geography and construction conditions or environmental impacts that restrict construction access or scheduling. Once the initial construction is complete, these factors may have little impact on O&M costs.

Topic: Transmission O&M Cost Study

Reference: 2010-03-04 AESO 2010 ISO Tariff - Appendix C - Transmission OM Cost Study.pdf

Preamble: IPCAA wishes to understand some of the mechanics of the Transmission O&M Cost Study.

Request:

- (a) Please confirm that G&A costs are allocated on the basis of all other O&M costs. If this cannot be confirmed, please explain.
- (b) Please confirm that when determining a weighted average of the allocation of capital and non-capital costs, allocating G&A costs on the basis of all other O&M costs has the effect of increasing the weighting of the O&M allocation. If this cannot be confirmed, please explain.
- (c) Please provide a discussion, for each component of G&A costs in AL Sch. 4.0, describing why it is appropriate to allocate the costs across all other O&M costs.
- (d) Please provide a discussion, for each component of G&A costs in AL Sch. 4.0, please indicate what portion of the cost element has been capitalized and is therefore reflected in capital costs.

Response:

- (a) Confirmed.
- (b) When allocating G&A costs on the basis of O&M costs, the rationale is that G&A costs are incurred in a similar manner as O&M costs. Allocating G&A costs on the basis of all other O&M costs has the effect of using the same allocation for all non-capital costs, which provides the appropriate weighting of the O&M allocation as discussed in part (c) below. Using capital costs as the basis for the allocation of a portion of the non-capital costs (the G&A costs) would have the effect of decreasing the weighting of, and therefore underweighting, the O&M allocation.
- (c) None of the components of G&A were found to have a cost causation relationship with either capital facilities or with O&M activities directly associated with the electric transmission system. The items in Schedule AL 4.0 include costs listed as Materials and Supplies, Office Expenses, Staff Expenses, Vehicles, Community Relations, Training and Other, Buildings, Telecommunications, Hearings, Self Insurance, and Other Taxes. Expenses such as Office Expenses, Staff Expenses, Training, Buildings, and Telecommunications will be a function of the number of staff employed and therefore appear to relate to O&M costs. All G&A costs were accordingly allocated on the same

basis as O&M costs. Other expenses such as Community Relations and Hearings are not necessarily related to O&M or to capital. For simplification, all G&A costs are allocated to functions on the basis of O&M costs.

- (d) The total amounts shown in AL Sch 4.0 are the costs that are expensed and are not capitalized amounts. The amounts removed for G&A that are capitalized are shown in the "Non-Labour – Indirect" line of AL Sch 4.0.

Topic: Transmission O&M Cost Study

Reference: 2010-03-04 AESO 2010 ISO Tariff - Appendix C - Transmission OM Cost Study.pdf
AESO Estimate of Transmission Cost Increases Spreadsheet – Nov 2009

Preamble: IPCAA wishes to understand implications of adopting the results of the Transmission O&M Cost Study into the AESO Tariff design.

Request:

- (a) Please confirm that as a result of adopting the functionalization recommended in the Transmission O&M Cost Study, approximately \$47 million in bulk wires costs were shifted to local transmission (\$31 million) and POD costs (\$16 million). If these numbers cannot be confirmed, please provide a calculation of the costs shifted as a result of adopting the Transmission O&M Cost Study.
- (b) Please confirm that the \$47 million in bulk transmission costs shifted from bulk transmission to local and POD respectively equates to roughly \$0.84/MW. If this value cannot be confirmed, please provide an alternative calculation.
- (c) Please provide a copy of the 6 worksheet Excel workbook developed by the AESO that provided a calculation of the rate impact resulting from Critical Transmission Infrastructure Capital Costs, Bill 50 Project Capital Costs and the \$14.5 Billion of Capital Costs.
- (d) Please discuss the extent to which the capital expenditures spending outlined in Worksheet 6 that are labeled as “various” bulk transmission projects and “long term regional transmission plan” (lines 31 through 39) would be largely considered as bulk transmission.
- (e) Please confirm that the workbook estimated that the incremental revenue requirement resulting from the annual spending outlined in Worksheet 6 indicates that capital expenditures labeled as “various” bulk transmission projects and “long term regional transmission plan” (lines 31 through 39) are estimated to have a cumulative rate impact of \$1.65/MWh in 2010, \$2.64/MWh in 2011 and \$4.43 in 2012 (line 88).

Response:

- (a) Confirmed, based on the amounts in the application as filed. The AESO notes that some corrections have been identified in information responses that will affect the quoted amounts, but not materially.

- (b) Confirmed, assuming the quoted value should have been \$0.84/**MWh** rather than /**MW**. Based on the 2010 forecast billing determinant of 55,865.5 GWh of DTS metered energy, the value would be calculated as:

$$\$47 \text{ million} \div 55,865.5 \text{ GWh} = \$0.84/\text{MWh}$$

- (c) Please see the attachment provided in information response AUC.AESO-021 (d).
- (d) Please see the attachment provided in information response AUC.AESO-021 (b). As provided in that attachment, the AESO estimates that the referenced projects would be functionalized as follows:

Description	Total	Bulk System	Local System	POD
	\$ 000 000	\$ 000 000	\$ 000 000	\$ 000 000
Various bulk system projects underway	\$570	\$570	-	-
Long-term regional transmission plan	3,872	-	3,029	843
Total	\$4,442	\$570	\$3,029	\$843
Percent of Total	100%	13%	68%	19%

Based on the amounts in this table, about 13% of the cost of the referenced projects would be considered as bulk system.

- (e) The referenced values appear on line 89 of Worksheet 6 of the attachment provided in information response AUC.AESO-021 (d), and are slightly different as provided in the table below. As well, the 2012 value includes the effect of \$1,046 million of costs related to projects originally identified as critical transmission infrastructure (CTI) in the *Long-Term Plan*, and a value with those amounts excluded is also provided in the table.

Attachment AUC.AESO-021 (d) Worksheet 6	2010	2011	2012
\$/MWh Incremental Revenue Requirement Amount (Line 89)	\$1.26	\$2.65	\$4.49
\$/MWh Incremental Revenue Requirement Amount (Line 89 Excluding CTI Projects)	\$1.26	\$2.65	\$3.25

(The AESO expects that the slight differences in the values quoted in the information request and those appearing in Attachment AUC.AESO-021 (d) arise from revisions to the model in November 2009, which are summarized in the first sheet in the workbook.)

Topic: Previous Cost Study

Reference: 2010-03-04 AESO 2010 ISO Tariff – Appendix C – Transmission O&M Cost Study, 1. Executive Summary (page 3)

Preamble: IPCAA wants to know how dated the costs are that were analyzed in the original Cost Study and if they are still affecting components of the current Cost Study and Rate Design.

Request:

- (a) Please identify the year or years of costs that were studied in the original Cost Study in the AESO 2006 General Tariff Application.
- (b) Please confirm that some of the functionalization and classification of costs from the AESO 2006 General Tariff Application are still being used in the Cost Study and Rate Design in the AESO 2010 GTA. If confirmed, provide an explanation as to why the original Cost Study is still an appropriate basis for rate design.

Response:

- (a) The *Alberta Transmission System Wires Only Cost Causation Study* that was dated January 25, 2005 and filed with the AESO's 2006 tariff application used property data from:
 - AltaLink as of April 20, 2003; and
 - ATCO Electric, ENMAX, and EPCOR as of December 31, 2002.
- (b) The *Wires Only Cost Causation Study* filed with the AESO's 2006 tariff application was updated in the *Transmission Cost Causation Update* filed with the AESO's 2007 tariff application, to address Alberta Energy and Utilities Board directions and stakeholder concerns. The property data included in the first study was not updated as part of that exercise. The **functionalization** of capital costs remains based on these studies in the 2010 ISO tariff application and affects the rate design for 71.4% of the interconnection charge in Rate DTS, which accounts for about 49% of the AESO's total revenue requirement.

In the AESO's 2007 tariff application proceeding, the classification of POD costs from the *Cost Causation Study and Update* was replaced by a POD cost function derived from analysis of connection projects, as discussed in section 4.3.1 (page 32) of the AESO's ISO tariff application. The POD cost function has been updated in the 2010 tariff application based on additional recent projects and further analysis. As a result, the **classification** of capital costs from the *Cost Causation Study and Update* affects the rate design for only 42.2% of the interconnection charge in Rate DTS, which accounts for about 29% of the AESO's total revenue requirement

The proportions of capital by function and classification will remain relatively constant as long as the transmission system remains relatively constant. As discussed in section 8.2 (page 261) of the application, “The AESO considers that a variety of system projects and connection projects have occurred over the past several years, such that the relative proportions resulting from the *Transmission Cost Causation Study* continue to be reasonably representative of the current transmission system.” Also in that section, the AESO recognized that significant transmission system changes are expected to occur over the next several years, and will consider an update to the *Transmission Cost Causation Study* for the AESO’s next comprehensive tariff application.

Topic: Revenue offsets

Reference: 2010-03-04 AESO 2010 ISO Tariff – Appendix C – Transmission O&M Cost Study, 4.1 Capital Related costs (page 8) and 4.3.3 Revenue Offsets (page 10)

Preamble: IPCAA wishes to understand how revenue offsets for labor are classified. Also, IPCAA seeks clarification on ENMAX and EPCOR revenue offsets.

Request:

- (a) PS Technologies indicates that revenue that offsets labour costs, such as affiliate revenue, was deemed to be non-capital related. Please explain this determination given that most labor is required for capital related costs as compared to non-capital related costs.
- (b) Does ENMAX or EPCOR have revenue offsets from affiliates for services, joint use (shared use of poles or other assets with other utilities or entities) and other services to outside parties? If yes, why were these revenue offsets not included in the Cost Study and appropriately functionalized and classified?

Response:

- (a) The labour included in the non-capital cost does not include the cost of labour that is capitalized as part of capital projects. Therefore, the revenue offsets associated with labour costs are considered non-capital.
- (b) ENMAX and EPCOR do have revenue offsets. The revenue offsets are already accounted for in the costs that were studied. For example, when there is revenue from a third party to lift a line, the revenue is accounted for as a negative in the wages cost and offsetting the wage of the lineman that has to be dispatched to lift the line. Therefore, the revenue offset is already appropriately accounted for.

Topic: Isolated Generation Station and Telecommunications Site Costs

Reference: Section 4.3.1 Fuel, see also Section 5.1 Cost Classification (page 16)

The amount of fuel used in the isolated generating plants is proportional to the energy consumption and is not directly linked to the peak demand, or number of customers being served. As a result, fuel costs (and variable O&M costs associated with isolated generation) are considered O&M costs and are functionalized as Local and POD and classified as energy related.

Preamble: IPCAA wishes to review the classifications and functionalization of these costs.

Request:

- (a) Please identify the amount of actual energy consumed by customers served by isolated generation plants and the amount of actual energy consumed by all other customers in the most recently available year.
- (b) Please confirm that customer load patterns and the associated transmission infrastructure for customers who are not served by isolated generation are not affected by load patterns of customers who are served by isolated generation. If not confirmed, please explain.
- (c) Please confirm that introducing a small energy price signal to customers not served by isolated generation to the DTS rate will not materially affect the load characteristics and usage patterns of customers in isolated generation communities. If not, please explain.
- (d) Please confirm that the amount of fuel used in isolated generation plants is not linked to the energy consumption, peak demand or number of customers being served for customers who are not in isolated areas? If not, please explain.
- (e) Please explain how other non-fuel costs in isolated generation communities are treated in the cost study from a functionalization and classification perspective.
- (f) Please confirm that costs incurred for isolated generation communities, including fuel costs, can be considered a transmission avoidance cost. If confirmed, does the AESO consider it reasonable that a transmission avoidance cost could be classified in the same manner that transmission costs are classified? If not, why not?
- (g) Please confirm that isolated generation costs, which are not normal transmission wires costs, are required by legislation and regulations to be pooled with the AESO's transmission costs in order to provide a postage stamp style tariff for these customers? If not, please explain.

- (h) Given your response to (f) above, is it reasonable to consider these costs as analogous to a tax imposed on other customers in order to achieve postage stamp rates? In other words, does the AESO agree that if cost of service principles were strictly applied and, in the absence of specific legislation regarding isolated generation costs, that customers served by isolated generation would pay higher than average rates? If not, please explain.

Response:

- (a) Recorded metered energy for customers served by isolated generating units was 64.9 GWh in 2009. Recorded metered energy for all market participants (including customers served by isolated generating units) under Rate DTS was 52,907.0 GWh in 2009. Therefore, isolated communities accounted for about 0.12% of the metered energy billed by the AESO in 2009.
- (b) The load pattern of any individual market participant is generally not affected by the load patterns of other market participants.

The transmission infrastructure of customers not served by isolated generation would be affected if the load of customers served by isolated generation increased such that it justified extending the transmission system to connect the isolated community.

- (c) Inasmuch as an energy price signal would influence behaviour to reduce energy consumption, it is reasonable to assume that such influence would affect isolated communities similarly to other market participants.

As well, the AESO recognizes that customers in isolated communities are served by ATCO Electric as distribution system owner. ATCO Electric receives system access service at many other points of delivery, and would therefore incur a non-trivial cost as a result of the POD energy price over all those points of delivery. The energy price signal aggregated over all ATCO Electric PODs could encourage ATCO Electric to take action to reduce that cost. One effective action could be to implement programs to reduce consumption and fuel use in isolated communities.

- (d) Confirmed.
- (e) The non-fuel variable costs of isolated generation are functionalized and classified in the same manner as the fuel costs of isolated generation in the *Transmission O&M Cost Study*.
- (f) The costs incurred for generating units in isolated communities does prevent or avoid the cost of providing transmission (or distribution) service to the isolated communities, because isolated generation is a more economical alternative than providing transmission to connect those communities. Functionalizing and classifying isolated generation costs based on an avoided cost approach is one method that could be used. The *Transmission O&M Cost Study* took the approach that the costs of isolated generation should be classified on the same cost-causation basis as other costs in the study, which reflects the manner in which a cost is incurred. For isolated generation, the cost causation basis results in those costs being classified as variable to energy production.

- (g) Confirmed. The *Isolated Generating Units and Customer Choice Regulation* establishes the pooling of costs associated with isolated generation, while the *Electric Utilities Act* establishes the “postage stamp” nature of the ISO tariff.
- (h) No, the AESO does not consider it reasonable to consider a cost treatment established by legislation to be analogous to a tax imposed on other market participants. The treatment of all costs incurred by the AESO is established to a greater or lesser extent by legislated requirements, as summarized in section 4.1 (pages 25-27) of the application.

The AESO agrees that, in the absence of specific legislated requirements and if cost causation principles were the only consideration, customers served by isolated generation would likely pay higher than average rates. To the extent that costs would be no longer averaged, some other market participants would likely also pay higher than average rates for system access service.

Topic: Treatment of G&A Costs

Reference: Section 4.3.2 Operating Cost

G&A costs are more general in nature and are not directly related to the operation and maintenance of the electric transmission system.

This Study ... does not study G&A costs.

Preamble: IPCAA wishes to better understand the nature of G&A costs.

Request:

- (a) Please confirm that it is also reasonable to claim that G&A costs are not directly related to the capital costs of the electric transmission system? If not, please explain.
- (b) Please explain why the Cost Study did not include a study of the G&A costs.

Response:

- (a) Please refer to information response CCA.AESO-019.
- (b) The functionalization and classification of G&A costs are not directly determinable. The independent functionalization of G&A costs would result in a subjective assessment that could not be objectively defended.

Topic: Treatment of G&A Costs

Reference: Section 4.3.4, Hearings, Self Insurance, Business Tax

The cost of hearings, self insurance and business tax are non-capital related costs and have, for the purpose of this Study, been defined as G&A because such costs are not directly linked to the operation and maintenance of the electric transmission system.

Preamble: IPCAA wishes to better understand the nature of G&A costs.

Request:

- (a) Please confirm that at least a portion of hearings, self insurance, and business tax are required as a result of capital expenditures. If not, please explain and include an explanation of the financial transactions and adjustments in support of your position.
- (b) If portions of these costs are the result of capital expenditures, why did the O&M Cost Study functionalize and classify these costs on the same basis as O&M costs?

Response:

(a-b) Not confirmed.

Costs of a hearing associated with a capital project are capitalized and do not show up in the non-capital costs. Costs of a tariff application proceeding are entered into a hearing cost reserve account, which is expensed. The matters addressed in a tariff application will include both O&M and capital.

Self insurance costs such as third party property damage and injuries (which includes claims adjusting expenses) do not result in a lasting benefit and are therefore expensed and not linked to capital.

Business taxes are a function of the business, not of the amount of capital employed in the business, and therefore do not track capital.

Topic: Functionalization

Reference: Section 5.1 Functionalization – Fuel Cost Functionalization

This fuel cost is considered transmission because in its absence, the transmission system would have to be expanded to provide service thereby incurring greater electric transmission costs. Since all of these communities are small, any transmission system would be built to interconnect would be a local system and POD.

Preamble: IPCAA wishes to better understand the basis for this conclusion.

Request:

- (a) Please identify the source for the conclusion that all isolated communities would be served by local transmission systems. Include all working papers, notes from meetings, and other documentation for this conclusion.
- (b) Please confirm that when utilities such as ATCO Electric are planning the routes for their bulk transmission systems, they take into account the location of isolated communities so that, if feasible, they will select routes that can supply those communities from the new bulk transmission system. If not confirmed, please explain.
- (c) Please identify all loads that were at one time isolated from the transmission system in the last 30 years and are now supplied from transmission lines. Identify which of these transmission lines serve a purpose beyond supplying the isolated load such as transferring power from one part of the AIES to another part.

Response:

- (a) The transmission system that would be built to serve an isolated community would be functionalized as local system and point of delivery based on the definitions used for those functions of the transmission system in the *Transmission Cost Causation Study*. The bulk system was defined as the part of the transmission system that delivers a large volume of electric energy over a long distance. The loads in isolated communities are small, and therefore the transmission line providing service to a remote community would not be considered bulk system. The implementation of this definition may be simplified to voltage levels.

All but two of the isolated communities have peak metered demands of less than 1 MW; the two larger isolated communities have peak metered demands of about 2 and 10 MW. This size of load would normally be served by extending the electric distribution system where the distribution system is available. A typical 25 kV distribution feeder has a thermal capacity of about 13 MW.

- (b) It is reasonable to expect that the AESO, the transmission facility owner, and the distribution system owner would work together to provide system access service from the interconnected electric system to remote communities where economically feasible. Given the small load at most of these communities as discussed in part (a) above, it is doubtful a bulk system line would be altered from the otherwise most economical route simply to connect a remote community.

As well, system access service from the bulk transmission system would usually require a 240/25 kV substation. A 240/25 kV substation is more expensive than the 144/25 kV substation that would be used for a connection to the local transmission system. A 240/25 kV substation is generally used only when there is no local system available in an area.

- (c) The AESO does not have a list of loads that were previously isolated and then connected to the transmission system over the last 30 years. The *Isolated Generating Units and Customer Choice Regulation* first came into force on January 1, 2001. The AESO is aware of only one isolated community being connected to the interconnected electric system since then: the previously isolated community of Fox Lake was connected via a distribution line to an existing transmission substation in 2005. The existing transmission substation is part of the point of delivery function in the *Transmission Cost Causation Study*.

Topic: Functionalization

Reference: Section 5.1 Functionalization – Operating – Net Salary

For the purpose of the System Control Center, the number of elements (lines and transformers) in service is used to functionalize costs.

It was not possible to determine cost causation for all groups.

Preamble: IPCAA wishes to better understand the basis for using the number of elements to functionalize costs for the System Control Center and why cost causation cannot be determined for some groups.

Request:

- (a) Please provide a list of all of the responsibilities and functions of staff working in a control centre. Divide the responsibilities into maintenance (including monitoring DFO activities), operations (such as monitoring voltage limits and line flows, developing switching schedules, managing and reporting on forced outages) and other categories (such as training, administration).
- (b) Please estimate the amount of time out of the entire working hours that are actually devoted to switching lines and transformers in and out of service.
- (c) For groups for which it “was not possible to determine cost causation”, provide the names and charges for each of these groups and explain why it was not possible to determine cost causation.
- (d) Did the Cost Study include interviews with managers and supervisors within the TFOs who directly responsible for the various cost categories? Were the TFOs uncooperative in explaining the nature of the costs?

Response:

- (a) The responsibilities of the System Control Centre personnel include:
 - monitoring the transmission system and addressing alarms that comes into the SCC;
 - following procedures to address the alarms that come in; and
 - switching elements in and out of service, blocking reclosers, and taking other actions in coordination with crews who are working on electric transmission facilities.

No study has been completed to try to separate control centre time or responsibilities into the two categories of operations and maintenance.

- (b) No time study has been completed to try to estimate the amount of time spent on various activities such as switching lines and transformers in and out of service or responding to an alarm such as low battery level that will impact all functions. The functionalization of the control centre was completed at an overview level of the purpose of the control centre, based on considerations such as the following.

System Control Centre operators ensure the safe and reliable operation of the electric transmission system. As the load changes, operators may switch capacitor banks and adjust tap changers to maintain voltage within the prescribed limits. These actions will impact voltage on the bulk system, local system, and points of delivery, and each action will not affect each function differently depending on the location and connectivity of the capacitor bank or transformer.

System Control Centre operators will also address system emergencies and will attempt to restore power remotely. If a transmission line is tripped out of service, operators may have to take action to attempt to restore the line to service, or dispatch crews to inspect the line, and complete repairs before bring the line back into service.

System Control Centre operators coordinate with crews to take equipment out of service for maintenance. The removal of equipment from service may require other actions to accommodate removing an element from service.

All of these activities occur coincidentally and are interrelated. Therefore, it is not practical to separate time and assign time to one of the three functions.

Therefore, in overview, the tools available to System Control Centre operators include operating circuit breakers and adjusting taps on transformers. While all of this equipment is located within substations, it would not be correct to functionalize this all as point of delivery, because operating circuit breakers also take lines out of service.

The proposed method of using transmission elements provides a practical means of functionalizing control centre costs, because the control centre is primarily in place to monitor and switch transmission elements.

There are variations on substations and points of delivery whereby some substations have multiple transformers and multiple circuits, whereas the simplest point of delivery may have only one line of supply and one out-going circuit. Therefore, using the number of substations is too simplistic for allocating control centre costs, and using the number of transformers is a better base for allocation.

- (c) The groups which were difficult to functionalize are listed at the bottom of AL Sch 5.0 and are Operations Management, IT, and Facilities. These groups do not work directly on electric transmission facilities and instead provide support to other groups that do work directly on electric transmission facilities. Therefore, the cost associated with these groups was allocated to the functions on the basis of all other Net Salary and Wages costs.
- (d) The compilation of the *Transmission O&M Cost Study* included interviews with either a director or vice president of each of the four largest TFOs. Interviews with managers or supervisors of every cost category were not conducted. All of the TFOs were cooperative and provided assistance.

Topic: Forecast versus actual data

Reference: Appendix A – O&M Cost of Service Study Schedules

Preamble: IPCAA wishes to know what cost allocations were based on actual costs and what allocations were based on forecast costs.

Request:

- (a) For the schedules in Appendix A, identify which of the costs are actual costs and which costs are forecast.
- (b) For the most current actual costs for each TFO, provide reconciliation with each of the total costs by TFO in Schedule Sum 1.0 and the revenue requirement in the relevant approved AUC Decision and include the Decision number.
- (c) For AL Sch 2.0, provide an explanation of the rounded nature of these amounts, from 2006 through 2009 and identify if these amounts are actuals, forecasts or estimates. Provide similar explanations for AT Sch 1.0, 2.0, 3.0 and 4.0.

Response:

- (a) Please refer to information response CCA.AESO-018.
- (b) The cost identified in the TFO tariff application is the starting point for the *Transmission O&M Cost Study*. The best data available is used to complete the functionalization and classification of costs, and allocation factors are developed to allow application to the total amounts from the TFO tariff application data.
- (c) In AL Sch 2.0, the line items of Miscellaneous Revenue are forecasts from AltaLink's 2009-2010 TFO tariff application, volume 1 of 2, section 4-3.

Topic: Functionalization of Costs

Reference: Appendix A – O&M Cost of Service Study Schedules, AL Sch 5.1

Preamble: IPCAA wishes to know that basis of functionalization of the Contracted Manpower Allocator (Contracts)

Request:

For the Contracted Manpower Allocator, provide a list of the contracts used to functionalize this cost item. Include in the list a description of the contract, the amount of the contract and how the cost was functionalized. Provide a reconciliation of the total of these contracts to the AltaLink schedules.

Response:

The contracts and their amounts contain commercially sensitive information. The operations performed by contracted manpower are outlined in section 5.4.2 of AltaLink's 2009-2010 tariff application. As shown in Table 5.4.1a in that section, the description of work covered in contracted manpower includes the following:

- ACC Consulting & Maintenance Contracts (AREVA, software upgrades);
- FortisAlberta/TransAlta Agreements (switching inspections);
- Consulting – Technical Studies (CSA standards, environmental, staff training external, search firms, summer students);
- Field Support (oil reclamation, corrective, preventative, emergency and predictive maintenance, WHVTC testing and repair of live line tools);
- Land Management (land consulting);
- Miscellaneous (PQ, encroachments, crossings, mobile radio);
- Line Patrols, Access, Line Maintenance; and
- Substation Maintenance (Doble, DGA testing, Hanta virus, battery maintenance, grid testing).

The list of contracts was reviewed confidentially with AltaLink personnel and functionalized based on the work that was completed within the contract, based on voltage level.

Topic: Demand Opportunity Service and Export Service Rates

Reference: Section 4.6 and 4.7

Preamble: IPCAA wishes understand why there are differences in the treatment of users of DOS and XOS

Request:

- (a) Please explain why a Rate DOS 1 hour customer has an allocated contribution to fixed cost of 50% of the fixed components of Rate DTS bulk and local system charges and Rate XOS 1 hour has only 20%;
- (b) Please explain why a Rate DOS 1 month customer has 100% of the fixed bulk system and 1200% of the fixed local system charges allocated and a XOS 1 month customer has only 30% of the fixed system and bulk charges allocated;
- (c) Please explain why Rate DOS for all three classes is assigned 100% of Operating Reserve costs and Rate XOS for both classes is assigned only 32% of Operating Reserve charges;
- (d) Please explain the rationale as to why a load customer outside of Alberta receives preferential treatment in use of the Alberta portion of the transmission system on an interruptible basis to a load customer within Alberta wishing to access the same system on an interruptible basis.

Response:

The allocation of costs to Rates DOS and XOS in the 2010 rate calculations follows the methodology approved for those rates in the AESO's 2007 tariff application proceeding.

In response to directions in Decision 2007-106, the AESO refiled the DOS 7 Minutes rate to include only the variable cost components of Rate DTS that were attributable to DOS 7 Minutes, which resulted in an increase of about 8% compared to the then-existing DOS 7 Minutes charge. The DOS 1 Hour and DOS Term rates included contributions to fixed costs which resulted in similar increases of 7% and 8%, respectively, compared to the then-existing DOS 1 Hour and DOS Term charges.

Also in response to directions in Decision 2007-106, the AESO refiled the XOS 1 Hour and XOS 1 Month rates to provide increases of 10% and 20%, respectively, over the then-existing Rate EOS charge.

The charges for Rates DOS and XOS in the proposed 2010 tariff have been based on the 2007 tariff calculation methodology which, as summarized above, was designed to provide specific levels of increases over the prior charges in Rates DOS and EOS. In effect, the charges in the

proposed tariff reflect historical differences between Rates DOS and XOS that have existed in the AESO's tariffs for several years. The AESO notes that opportunity service rates generally reflect a value-of-service rather than cost basis.

With this background, the AESO provides the following responses to the specific questions posed in the information request.

- (a) As discussed in the opening paragraphs of this response, the costs allocated to Rates DOS and XOS primarily reflect historical differences between those rates that have existed in the AESO's tariff for several years. The AESO considers that this historical difference reflects the following considerations:
- Rate XOS 1 Hour is recalled before any Rate DOS type;
 - Rate DOS includes the same operating reserve charge as Rate DTS because DOS and DTS load cannot be distinguished at a site for operating reserve calculations, while Rate XOS includes only a portion of the Rate DTS operating reserve charge to reflect those hours in which exports do not cause the AESO to procure additional operating reserves (as discussed in part (b) of section 4.7.1 (pages 51-52) of the application); and
 - Rate DOS charges must be high enough to prevent "cannibalization" of Rate DTS firm load at a site, while Rate XOS is an independent service not associated with firm load at the same site.

In consideration of all the above, the AESO considers that the proposed allocation of costs to Rates DOS 1 Hour and XOS 1 Hour is fair and reasonable. As well, the AESO notes that it is reviewing export service rates and may propose additional rates in the future, as discussed in section 4.7.2 (page 52) of the application.

- (b) Based on the details of the question, the referenced rate is DOS Term rather than DOS 1 Month. As discussed in the opening paragraphs of this response, the costs allocated to Rates DOS and XOS primarily reflect historical differences between those rates that have existed in the AESO's tariff for several years. The AESO notes that Rate XOS 1 Month is recalled before any Rate DOS type.

In addition, as discussed in the AESO's 2007 tariff application refiling, DOS Term includes a larger contribution to fixed costs to ensure market participants are not enticed to use DOS Term as a replacement for Rate DTS for extended periods of time. A similar consideration does not apply to Rate XOS 1 Month as there is no "firm" equivalent to Rate XOS. As well, the AESO notes that it is reviewing export service rates and may propose additional rates in the future, as discussed in section 4.7.2 (page 52) of the application.

- (c) Please refer to the second bullet point in part (a) above.
- (d) As discussed in the opening paragraphs of this response, the costs allocated to Rates DOS and XOS primarily reflect historical differences between those rates that have existed in the AESO's tariff for several years. Also, the lower charges in Rate XOS reflect:
- greater likelihood of curtailment of Rate XOS due to its lower priority than Rate DOS;
 - allocation of only a portion of the Rate DTS operating reserve charge to Rate XOS to reflect those hours in which exports do not cause the AESO to procure additional

- operating reserves (as discussed in part (b) of section 4.7.1 (pages 51-52) of the application); and
- the inability of Rate XOS to be substituted for a “firm” export service due to the unavailability of such as service.

As well, as noted in parts (a) and (b) above, the AESO is reviewing export service rates and may propose additional rates in the future, as discussed in section 4.7.2 (page 52) of the application.