

Title: DTS Interconnection Charge Rate Design (EUB Issue Number 3.6)

Preamble: "...to the extent that the bulk system is planned to meet future loads on the system as indicated in part by customers' contracted capacity, the AESO considers that bulk system billing should include a contract capacity component."

Reference: s. 4.3.2, p. 12 of 53, l. 20

Request:

- (a) Please provide a copy of the AESO's report entitled "Northeast Alberta Service Requirements Forecast", which was released in draft on September 5, 2006 (RP-05-540).
- (b) Please explain how the AESO uses DTS contract capacities for the planning of the bulk system to meet future loads.
- (c) Please explain how the AESO uses STS contract capacities for the planning of the bulk system to meet future loads.
- (d) Please explain how the AESO uses forecast coincident demand for the planning of the bulk system to meet future loads.
- (e) Please discuss cost causation between DTS contract capacities and bulk system costs for dual-use customers.

Response:

- (a) Please see the attached Northeast Alberta Service Requirements Forecast.
- (b) The AESO indirectly uses DTS contract capacities for planning by using a forecast of the future peak demand at individual points of delivery and applying a coincidence factor to arrive at the coincident demand for the region under study.
- (c) The STS contract capacity is used as the limit for the maximum output onto the system from a point of supply.
- (d) The time of day and system conditions for which different sections of the bulk system are most stressed may or may not coincide with times of peak system load or regional peaks. Transmission system adequacy is tested by evaluating the impact of various summer and winter system conditions such as: regional peaks, shoulder periods and light load. Forecast coincident system demand is reviewed as part of the bulk system planning but is not the most stressed condition.

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

Title: POD Charge Rate Design (EUB Issue Number 3.8)

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

”The third component [of Equation 6, p.23 of Appendix F] represents the average POD cost increase per MW of DTS capacity, and should not include the substation fraction.”

Reference: s. 4.5.2, p. 21 of 53, l. 32 & Appendix F, Customer Contribution Study, p. 23-24

Request:

- (a) Please explain why the cost function on which the POD charge is proposed (Equation 1 in application, Equation 5 in Appendix F) does not include both single and multiple customer load projects.
- (b) Please explain why the third component [of Equation 6, p.23 of Appendix F] should not have the substation fractions applied for multiple load customers served from a substation.
- (c) Please explain why the third component [of Equation 6, p.23 of Appendix F] should not have the substation fraction applied for a single dual-use load customer served from a substation.

Response:

- (a) The quoted reference incorrectly states the data on which the recommended cost function was based. The data included both single-service and multiple-service load-only interconnections, as indicated in the “# of Customers” column in the contribution study data provided as Appendix G to the AESO’s 2007 GTA.

The data actually included 16 projects with multiple load services and 14 projects with single load services.

- (b-c) The average cost function which underlies both the proposed contribution policy and the proposed POD charge is the single line:

$$\text{Average Cost} = \$4.451 \text{ million} + (\$0.154 \text{ million/MW} \times \text{DTS Capacity})$$

As discussed in section 6.5.3 of the AESO's 2007 GTA, this cost function reasonably represents the average cost of a project of 7.5 MW or greater capacity. The \$4.451 million fixed component represents the average fixed cost incurred for such a project, while the \$0.154 million/MW demand component represents the average increase in costs with an increase in capacity.

This average cost function is similar in structure to the cost function utilized for the AESO's current tariff, which is \$2.5 million + (\$0.1 million/MW × DTS Capacity). In the current tariff, the fixed component is shared between multiple services at a substation by applying the substation fraction, while the demand component is applied in full to the DTS capacity of each service at the substation. The AESO suggests this approach is appropriate, and proposes it be continued in the 2007 tariff.

It is appropriate that the fixed component be shared between multiple services because multiple fixed costs are not incurred when multiple services are interconnected at a single substation. For example, an "average" single transmission substation serving three DTS customers would not give rise to fixed costs of \$4.451 million × 3 = \$13.353 million. The EUB has approved the substation fraction, which represents the ratio of each customer's contract capacity to the sum of all customers' contract capacities served through the same substation, as a reasonable means of apportioning the fixed component between multiple services at a substation. The same approach is used to allocate the fixed component to a load service that shares a substation with a generator, such that the load service is indifferent to the nature of the other service or services interconnected at the same substation.

It is also appropriate that the demand component not be shared between multiple services but apply in full to each service interconnected at a single substation. An increase in capacity of any individual service may give rise to increased costs at the substation. For example, if two 10 MW load services exist at a substation, an increase of either of the services to 30 MW would potentially require a transformer upgrade as the substation would need to supply 40 MW of capacity rather than 20 MW. Furthermore, only the customer whose load is increasing should see increased bills as a result, since the customer whose capacity is remaining at 10 MW is not causing any increase in costs at the substation. It would therefore be unreasonable to apply the substation fraction to the demand component of the cost function, as it would under-allocate costs to the customer whose capacity is increasing and over-allocate costs to the customer whose capacity remains the same.

The same approach should also be used where load and generator services are provided at a dual-use substation. The AESO recognizes that in such a case the cost basis for the approach is less clear, as an increase in capacity of the load service may or may not give rise to increased costs at the substation. For example, if 10 MW of DTS capacity and 40 MW of STS capacity are served through the same substation, an increase in DTS capacity may not give rise to increased costs at the substation. On the other hand, if the DTS capacity is equal to or greater than the STS capacity, a capacity increase of the load service could require an upgrade at the substation. In the case of a

dual-use substation, uniform and predictable application of the rate, both between load services at different dual-use substations and between load services at multiple-load substations, should be given consideration. In particular, the load service should remain indifferent to the nature of the other service or services interconnected at the same substation. The AESO therefore proposes that, to preserve consistency among all load services, the demand component not be adjusted by the substation fraction for load services at dual-use substations.

The AESO notes that, for simplicity, the above discussion has been presented in the context of the single-line average cost function first presented above. This cost function is appropriate for most multiple-service substations, as the majority serve more than 7.5 MW of total contract capacity as discussed in the quoted reference from page 21 of section 4 of the Application. However, the fixed component of the average cost function was further modified for small projects to result in the recommended cost function of:

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

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.

Title: Substation Costs (EUB Issue Number 3.14)

Preamble: The DUC notes that for the subset of projects in the Customer Contribution Study used to analyze substation costs (spreadsheet 2006-11-03 AESO 2007 GTA - G Contribution Study Data.xls, tab Cost Data Subs 2007), transformation costs are 25% of the total substation costs.

Reference: App. G, Customer Contribution Study, p. 14, Substation Costs & s. 4.9, p. 51 of 53, l. 30

Request:

- (a) For the above referenced spreadsheet, please define the following column headings, using Project # 230 (856S) as an example:
 - (i) Sub Capacity, and if this is equal to DTS Contract Capacity?
 - (ii) MVA Rating
 - (iii) Total MVA
 - (iv) PV Rate, and why this value is calculated?
- (b) For the above referenced spreadsheet, are the Substation Costs in 2007 dollars, or the dollars of the year the project was completed?
- (c) Are the Present Value Index escalation rates (e.g. 2.2% from 2005 to 2006) consistent with the AESO's experience of cost increases from the TFOs for transmission projects (for both cost estimates and actual project costs).
- (d) Please provide distinct average substation equations (similar to p. 18, line 33) for substations serving a single customer and for substations serving multiple customers. Please explain the differences for these two cost equations.

Response:

- (a) Using project #230, the AESO provides the following clarification:
 - (i) The Sub Capacity of 18.0 MW is equal to the current DTS Contract Capacity
 - (ii) The MVA Rating is equivalent to the highest transformer MVA rating at the substation. That is, where there is only one transformer at a substation, the MVA Rating will be equal to the Total MVA, but where there are two transformers at a substation (as indicated in Column I – "Transformers"), the MVA Rating is the rating at the highest rated transformer. Using project #230, the facilities station has two transformers. One transformer has an MVA Rating of 200, the other transformer has an MVA Rating of 50, and accordingly Project # 230 has an MVA Rating of 200.
 - (iii) The two transformers make up a Total MVA of 250.
 - (iv) The "PV Rate" is simply the value used to escalate the project costs to 2007 dollars. This may be more appropriately labeled "FV Rate", that is, the value

represents the escalation multiplier used to determine the future value of the project costs.

- (b) Referring to Substation Costs, the tab labeled "Cost Data Subs 2007" are the inflated cost values. The values provided in Column D "Year" represent the base year from which the dollars were inflated.
- (c) Please refer to the response to Information Request TCE.AESO-065 (a-c).
- (d) The AESO's tariff for system access service (i.e. rates and terms and conditions, including the contribution policy) applies to all customers equally, regardless of how many customers may be attached to a particular facility. Therefore, the AESO did not, and does not believe it is appropriate to, determine distinct cost functions on the basis of the number of customers at a facility.



Title: DTS Power Factor Deficiency Charge (EUB Issue Number 3.27)

Preamble: Application of the DTS Power Factor Deficiency Charge to dual use customers

Reference: s. 4.5.4, p. 31 of 53, l. 16

Request:

Please provide a copy of the application amendment related to the application of the DTS Power Factor Deficiency Charge to dual use customers.

Response:

The AESO notes that the analysis, which will be filed when it is complete, is with respect to distribution-connected generation downstream of a DTS point of delivery, where operation of the generator is not evident in the data metered at the DTS POD. At dual-use substations, the customer contracts for both DTS capacity and STS capacity, and the load and generation are separately metered for the application of the AESO's tariff. No amendment of the power factor deficiency charge is expected to be applicable to dual-use customers.

Title: Backup Rate Considerations (EUB Issue Number 3.28)

Preamble: “The Board agrees with the parties that the development of a standby rate would be appropriate and may offer some flexibility to low load factor customers. However, the Board cautions parties that such customers impose significant costs with respect to the local system and POD costs and therefore, they must remain responsible for those costs. The Board has no specific directions with respect to stand-by rates, however.”

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

“The AESO suggests such conditions or restrictions on eligibility could be considered preferential or arbitrary. For example, backup service is characterized by short duration, infrequent, and unscheduled usage, and those characteristics could also be exhibited by a low load factor load service which intermittently runs above contracted capacity (for example, periodic operation of equipment in a large-machinery testing facility).”

Reference: Decision 2005-095, p. 30; s. 4.6, p. 32 of 53, l. 16 & s. 4.6.1, p. 34 of 53, l. 36

Request:

- (a) The objective of developing a backup rate appears to be to address the “partial requirements” category (a) noted above (p. 32, l. 45). Please discuss the limitations of developing a Stand-By rate that is only eligible to customers who have a STS contract.
- (b) Please confirm that if the Backup rate was only eligible to customers who have a STS contract, the concerns with “over usage” reference on p. 34, line 6-17 would be significantly diminished.
- (c) If a backup rate was limited to customers who have a STS contract, please provide an estimate of the amount of related load (DTS contract capacity at the same POD) that could utilize the backup rate (i.e. update the statistics provided on p. 34, l. 23 for dual-use customers only).
- (d) Please provide a copy of the constraints management rule referenced on p. 34 at line 46, and any additional information available on the application of this rule, e.g. who it will apply to, when it will be implemented, etc. Please also provide documentation on the development of this rule, including consultation with stakeholders.

Response:

- (a) Please refer to the response to Information Request TCE.AESO-036 (b).

- (b) Not confirmed. Please refer to the response to Information Request IPCAA.AESO-038 (a-b) for a discussion of the nature of the AESO's concerns. Please refer to the response to Information Request EnCana.AESO-027 (b) for comments on the possibility of incremental backup load.
- (c) Please refer to the response to Information Request IPCAA.AESO-047 (b).
- (d) The constraints management rule has not yet been finalized. Please refer to the response to Information Request EnCana.AESO-029 (b).

Title: Backup Rates (EUB Issue Number 3.28)

Preamble: Backup rates in other jurisdictions.

Reference: s. 4.6.2, p. 36 of 53, l. 12

Request:

- (a) Please provide a copy of the Arizona rate referenced.
- (b) Please provide copies of any other backup rates the AESO has found in its review of this issue.

Response:

- (a) Please see the attached Pricing Plan PRS-14 of Tuscon Electric Power. The first clause of the Terms and Conditions on page 3 of Pricing Plan PRS-14 states, "However, when the Customer's Partial Requirements Usage Percentage (PRUP) in any given billing period exceeds 5%, the Customer's Energy Charge per kWh under Backup/Standby Service will be converted to the Energy Charge per kWh under Supplemental Service for all kilowatt-hours in excess of 5% for the billing period." The "Partial Requirements Usage Percentage (PRUP)" is essentially the load factor for backup or standby service.
- (b) The AESO did not review specific rates of other utilities when examining the requirement for a backup or standby service. Instead it relied on research already completed by other organizations such as *Rate Structures for Customers With Onsite Generation: Practice and Innovation* by L. Johnston, K. Takahashi, F. Weston, and C. Murray (National Renewable Energy Laboratory, Golden, Colorado, December 2005) as referenced on page 32 of section 4 of the AESO's 2007 GTA. That specific report noted, "The researchers reviewed regulatory decisions, tariffs, legislation, and other policy documents in Arizona, California, Indiana, Massachusetts, Minnesota, New York, Oregon, Rhode Island, Texas, and Vermont."

Title: Backup Rate Costs (EUB Issue Number 3.28)

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

- They contract for the capacity needed during the backup load conditions, and thereby minimize the probability of capacity or other system constraints; or [Response 1]
- They contract for the capacity needed during normal load conditions, incur ratchets based on the capacity needed during the backup load conditions, and incur higher probability that constraints may exist at those times. [Response 2]”

“The AESO therefore concludes the proposed DTS rate accommodates the cost and rate design considerations related to the provision of backup service. The contract capacity and ratchet structure of the proposed DTS rate is a reasonable approach which balances facilities costs attributed to backup service and risk mitigation. Based on this conclusion, a separate backup rate is not proposed.”

Reference: s. 4.6.1, p. 33 of 53, l. 25 & s. 4.6.3, p. 38 of 53, l. 45

Request:

- (a) Please confirm that the analysis presented on page 38 assumes that a dual-use AESO customer is operating under Response 2 as noted above. Please explain your response.
- (b) Please confirm that a dual-use AESO customer operating under Response 1 above, with a DTS “contract for the capacity needed during the backup load conditions” would not experience “the annual charge for 1 MW of backup load would be about 45% of the annual charge for 1 MW of normal load.” Please explain your response.
- (c) Please provide an estimate of the portion of dual-use customers requirements (number of PODs and total DTS Contract capacity) who operate under Response 1 and who operate under Response 2, as described above.
- (d) Please confirm that an AESO dual-use customer who operates under Response 1 could see that same benefit as an AESO dual-use customer who operates under Response 2 if the AESO proposed a backup rate that was equivalent to the proposed DTS rate, with the Billing Capacity definition revised to exclude Contract Capacity (i.e. remove item (iii) 90% of Contract Capacity from the definition of Billing Capacity).

- (e) Please provide a proposed backup rate that is limited to AESO customers who have a STS and DTS contract that, in the AESO's view, would appropriately respond to Decision 2005-095.

Response:

- (a) Not confirmed. The analysis on page 38 would provide the same result whether the customer contracted for backup load (such that the 90% contract minimum established the DTS billing capacity in 11 months) or contracted for normal load (such that the 90% 24-month ratchet provision established the DTS billing capacity in 11 months).
- (b) Not confirmed. Please see part (a) above.
- (c) Please refer to the response to Information Request EnCana.AESO-028.
- (d) Not confirmed. Customers operating under both response scenarios see the same benefit of the proposed DTS rate, as discussed in part (a) above.
- (e) The AESO considers that the examination of backup service provided in section 4.6 of its 2007 GTA appropriately responds to Decision 2005-095.

Title: DOS for Dual-Use Customers (EUB Issue Number 3.29)

Preamble: DUC wishes to better understand the proposed application of DOS for dual-use customers during a planned generation maintenance period.

“DOS Term includes one qualifying criterion in addition to the DOS 7 Minutes and DOS 1 Hour criteria: the customer may require increased electrical consumption during planned maintenance of an on-site generator and would otherwise reduce load to avoid the ratchet on the standard DTS rate.”

Reference: s. 4.7, p. 47 of 54

Request:

- (a) For the above quote from the application (s. 4.7, p. 43 of 53, l. 14), please advise if the additional criterion is proposed or existing, and where this criterion is noted in the proposed or existing tariff.
- (b) Please provide a copy of the Demand Opportunity Service Business Practices.
- (c) Please advise which DOS rate the term “DOS Standard” in the *Demand Opportunity Service Business Practices* references to.
- (d) In the application (s. 4.7, p. 43 of 53, l. 20) the AESO states that “the AESO’s consideration of the provision of backup service in section 4.6 of this Application resulted in the proposal to relax the qualifying criteria for DOS Term to permit its use for planned generator maintenance.” Please explain the how the existing qualifying criteria for DOS Term will be relaxed from the criteria provided under Appendix A of the existing *Demand Opportunity Service Business Practices*.
- (e) Please explain what changes to the DOS rates the AESO is proposing to meet the needs of dual-use customers who may wish to use a DOS rate during a planned generation outage (i.e. meet the *Scheduled Maintenance Service* requirement (a) as noted on p. 32 of 53, l. 19 and l. 36).

Response:

- (a) The criterion discussed is a proposed change to the DOS commercial eligibility criteria. The proposed change is discussed in Section 4.7 Page 43 of the Application. If the AESO’s proposal is approved by the EUB, the AESO will update its business practices and distribute them to stakeholders.
- (b) Please see the attached DOS Business Practices.
- (c) Please see the response to part (a) above.

- (d) The use of DOS for Generator Maintenance as outlined in the DOS business practices is reproduced below (emphasis added):

3. Use of DOS for Generator Maintenance

Subject to the restrictions described under “Stand-by Use” below, DOS may be used for increased electrical consumption during planned maintenance of an on-site generator that normally supplies energy to an industrial process on the same premises. The customer must demonstrate that it would reduce the load of its industrial process in these circumstances rather than accepting the consequences of the increased Ratchet Level that would occur if DOS were not available. DOS Term is the only type of DOS available for generator maintenance.

The AESO proposes to no longer require the customer to demonstrate that it would reduce load to its industrial processes when conducting planned generator maintenance.

- (e) Please see Section 4.7 page 43 of the Application.

Title: Substation Fraction Definition (EUB Issue Number 5.1)

Preamble: Should the proposed definition of substation fraction specifically apply to load components of the tariff?

““Substation Fraction” means the ratio of the Contract Capacity for the Point of Delivery to the sum of all Contract Capacities (for DTS and STS) at the substation at which the Point of Delivery is interconnected”

Reference: s. 6.1, p. 2 of 47, l. 34

Request:

- (a) Given the proposed application of the Substation Fraction, should the numerator be “DTS Contract Capacity” rather than “Contract Capacity”? If not, please explain why not.
- (b) Similarly, would it add clarity to rename from “Substation Fraction” to “DTS Substation Fraction”? Please explain your response.

Response:

- (a-b) While the AESO agrees that the Substation Fraction will apply to DTS customers, the inclusion of Point of Delivery in the proposed definition inherently limits its application to those customers. Therefore the definition does not need to be modified.

Title: Customer Contribution Study (EUB Issue Number 5.10)

Preamble: From spreadsheet 2006-11-03 AESO 2007 GTA - G Contribution Study Data.xls, tab Cost Data Subs 2007, the DUC notes that the largest Sub Capacity project is 27 MW, whereas from Appendix E there are 102 (21% of total) PODs with DTS Contract Capacity greater than 30 MW.

Some new dual-use customer PODs will likely have DTS contract Capacities in excess of 30 MW.

Reference: s. 6.5.3, p. 15-24 of 47, l. 34 & Appendix G

Request:

Is the AESO comfortable that the projects used for the Customer Contribution Study are representative of the costs for new PODs with Contract Capacities above 30 MW? Please explain your response.

Response:

The AESO acknowledges that data collected for the Customer Contribution Study does not include data for PODS with DTS Contract Capacity greater than 30MW. Notwithstanding, the AESO is of the view the proposed cost function derived from the data is appropriate for all load sizes for the purposes of establishing the basis for a maximum investment function that satisfies the "80/20 rule", results in intergenerational equity, and aligns with the proposed tariff.



Title: Terms and Conditions related to DTS Contract Capacity reductions (EUB Issue Number 5.17)

Preamble: "Customers may provide an additional notice of reduction after an excursion so Contract Capacity will be reduced to previous notice levels."

Reference: s. 6.7, Article 14.3, page 35 of 47, l. 39

Request:

- (a) Please explain the application of the proposed provision noted above.
- (b) Please provide an example of the application of the proposed provision noted above.

Response:

(a) The proposed addition was intended to clarify that, if customers set a new peak during their 5-year reduction period and wish to return to the original reduced contract capacity, they must provide 5 years' notice for the incremental amount of contract capacity.

(b)

Original contract capacity:	10 MW
Proposed contract capacity:	5 MW
Reduction notice to AESO:	January 1, 2005
New demand:	11 MW
New demand date:	January 1, 2007
Reduction notice to AESO:	January 1, 2007
Reduction notice amount:	1 MW (11 MW - 10 MW)
Original Notice Period:	
Contract capacity:	6 MW
Effective:	January 1, 2010
New Demand Notice Period:	
Contract capacity:	5 MW
Effective:	January 1, 2012



Title: Terms and Conditions related to DTS Contract Capacity reductions (EUB Issue Number 5.17)

Preamble: “Contract Capacity reduction or termination lump sum payment charges will be based upon the present value of the System Charge as provided in the rate schedule DTS”

Reference: s. 6.7, Article 14.4, page 36 of 47, l. 4

Request:

Please confirm that the lump sum payment charges will be based upon the present value of the demand component of the System Charge, and not the Metered Energy component. If not confirmed, please explain.

Response:

Confirmed.

Title: Customer Owned Substations (EUB Issue Number 8.2)

Preamble: “Application of Primary Service Credit — As already noted, section 12(1)(a) of the Transmission Regulation provides for the ownership and operation of transmission facilities by the incumbent transmission facility owner. In accordance with the Regulation, the AESO will directly assign transmission projects to incumbent TFOs, including all high voltage switching equipment, buswork, and associated land. However, a customer may still elect to own and operate the step-down transformer, and by doing so may be eligible for the Primary Service Credit.”

Reference: AESO 2005-06 GTA, s. 4.9, Rate Design, PSD, page 35 of 51 & FIRM.AESO-227 (a)

Request:

- (a) Please provide the AESO’s position on customer ownership of substations.
- (b) Please provide a list of all substations built since the enactment of the Transmission Regulation where the substation is customer owned.
- (c) Please provide a list of all substations built since the enactment of the Transmission Regulation where the transformation is customer owned.
- (d) For any customer owned substations built since the enactment of the Transmission Regulation, please confirm that the AESO has exercised its discretion under s. 12(2) of the Transmission Regulation.
- (e) Please list and rationalize the criteria the AESO currently uses and intends to use under the 2007 Tariff to determine if a customer can own a substation.

Response:

- (a) The Hydro and Electric Energy Act (HEEA) part 3 section 24 provides an exemption from the HEEA for a person to distribute electric energy solely on their own land, for their own use, and not across a public highway. Where a person qualifies for this exemption, the AESO considers that the customer may own a transmission substation.

In the event the substation is required to provide service for other purposes, it is AESO’s position that it must then be owned by a Transmission Facility Owner (TFO), subject to all associated statutory requirements and obligations.

- (b-c) Nexen/Opti Long Lake 841S
MEG Conklin 762S
CNRL Horizon (forecast in service date 2007)

- (d) Not confirmed. The AESO does not consider a customer-owned substation to fall under the intent of section 12(2) of the Transmission Regulation until such time as the substation is required for purposes other than the customer's own use. To date these circumstances have not arisen since the enactment of the Regulations.
- (e) Please see part (a) above.