Topic: Cost Functionalization and Classification

Reference: Application, Section 4.3, page 28

Request:

(a) Please provide a copy of the Alberta Transmission Wires Only Cost Causation Study referenced at paragraph 131 on page 28.

(b) Please provide a copy of the Transmission Cost Causation Update referenced at paragraph 132 on page 28.

Response:

(a) Please see Attachment AUC.AESO-001 (a), which is the Transmission System Wires Only Cost Causation Study dated January 25, 2005 and filed as Appendix B to the AESO’s 2006 tariff application.

(b) Please see Attachment AUC.AESO-001 (b), which is the 2006 Transmission Cost Causation Update dated September 15, 2006 and filed as Appendix C to the AESO’s 2007 tariff application.
Topic: Electric Transmission Operating and Maintenance Cost Study

Reference: Application, Appendix C, page 9

Preamble: At page 9, Appendix C indicates that general and administration (G&A) costs are allocated in proportion to O&M costs.

AUC Rule 026 approved on May 19, 2009 requires that regulated utilities adhere to International Financial Reporting Standards (IFRS) for certain regulatory accounting and reporting purposes. Among the IFRS requirements adopted for regulatory purposes in Rule 026 is section 6(2), which requires AUC regulated utilities to adhere to an IFRS requirement prohibiting the capitalization of costs that are not directly attributable to an asset.

It is anticipated that when section 6(2) of Rule 026 takes effect, a portion of the TFO general administrative overhead costs that have previously been capitalized would be treated as expenses in 2011 and beyond.

Request:

How should G&A costs be functionalized, should they be functionalized in the same manner as capital costs or in the same manner as other O&M costs? Please explain the AESO’s rationale for either case.

Response:

The functionalization of G&A costs is a challenge because there is no direct causal relationship between the incurrence of costs and the activities associated with operating and maintaining the electric transmission facilities. The Transmission O&M Cost Study was based on the capitalization policies that have been in place and have governed the amounts considered capital by TFOs. The Transmission O&M Cost Study made the assumption that if a cost was capital related, it did not show up as a non-capital cost in the TFO’s tariff application. By deduction, the non-capital costs could not be attributed to capital projects and therefore had to be attributed to something else, and the only other readily available factor is O&M.

There is merit in reviewing the costs that will no longer be considered capital costs under IFRS because they are not directly attributable to an asset. If the incurrence of these costs is more closely related to capital than to O&M, then the costs may still be considered capital for the purpose of a cost causation study. Exceptions were made in the Transmission O&M Cost Study whereby costs generally considered operating (linear taxes and structure payments) were reviewed and changed to capital since their incurrence is more closely tied to capital than to operating.
Topic: Proposed Changes to Rate FTS

Reference: Application, Section 4.5, page 46, page 45

Preamble: The AESO stated that “The northwest Alberta transmission development is a comprehensive transmission concept to address systems needs of the northwest area, including Fort Nelson. The development was based on a need analysis that forecast a load of 1,310 MW in the northwest area in 2014-2015, including 25 MW of load in Fort Nelson.”

It also stated that “The AESO and BC Hydro have exchanged forecast information and co-operated to understand both the elements included in the AESO’s Northwest Alberta Transmission Development plan and the options that could potentially accommodate additional load in Fort Nelson.

Request:

(a) What are the AESO’s obligations for service to Fort Nelson?

(b) What is the Fort Nelson, B.C. load that the AESO is currently serving?

Response:

(a) The AESO considers it has an obligation to provide system access service to BC Hydro at Fort Nelson, but not to do so under the “postage stamp” provision of section 30(1) of the Electric Utilities Act.

The AESO’s obligation with respect to providing system access service is set out in section 29 of the Electric Utilities Act and its related definitions, as follows:

Interpretation

1(1) In this Act,…

(ee) “market participant” means

(i) any person that supplies, generates, transmits, distributes, trades, exchanges, purchases or sells electricity, electric energy, electricity services or ancillary services, or

(ii) any broker, brokerage or forward exchange that trades or facilitates the trading of electricity, electric energy, electricity services or ancillary services

(yy) “system access service” means the service obtained by market participants through a connection to the transmission system, and includes access to exchange electric energy and ancillary services
Providing system access service

The Independent System Operator must provide system access service on the transmission system in a manner that gives all market participants wishing to exchange electric energy and ancillary services a reasonable opportunity to do so.

Based on the system access service provision in the Act, the AESO considers that it has an obligation to serve BC Hydro at Fort Nelson similar to its obligation to serve other market participants, as there are no distinctions mentioned in the Act with respect to system access service between any market participants on the transmission system.

The Act sets out other provisions which clearly establish that certain obligations of the AESO are only with respect to Alberta, including the follows (bolding added).

Duties of Independent System Operator

The Independent System Operator has the following duties:…

(c) to determine, according to relative economic merit, the order of dispatch of electric energy and ancillary services in Alberta and from scheduled exchanges of electric energy and ancillary services between the interconnected electric system in Alberta and electric systems outside Alberta, to satisfy the requirements for electricity in Alberta…

(k) to collect, store and disseminate information relating to the current and future electricity needs of Alberta and the capacity of the interconnected electric system to meet those needs, and make that information available to the public

Transmission system planning

The Independent System Operator must forecast the needs of Alberta and develop plans for the transmission system to provide efficient, reliable and non-discriminatory system access service and the timely implementation of required transmission system expansions and enhancements.

Alleviation of constraints or other conditions on transmission system

When the Independent System Operator determines that an expansion or enhancement of the capability of the transmission system is or may be required to meet the needs of Alberta and is in the public interest, the Independent System Operator must prepare and submit to the Commission for approval a needs identification document…

Based on these additional provisions, the AESO considers that it does not have obligations to satisfy the requirement for electricity, manage information related to the electricity needs, forecast the needs, or expand or enhance the transmission system to meet the needs of BC Hydro at Fort Nelson. The Act clearly states that the AESO’s obligations relating to these matters are with respect to Alberta. The AESO accordingly
concludes it provides a different class of system access service to BC Hydro at Fort Nelson compared to within Alberta, reflective of those different obligations.

Alberta Energy and Utilities Board Decision 2005-096 on the AESO’s 2005-2006 tariff application (section 5.7, page 32) supported this view by stating:

_The Board cannot ignore the obvious – Fort Nelson is not located in Alberta. As such, the Board does not consider that the AESO is obliged to offer the postage stamp service that it is obligated to provide to Alberta customers._

_Equally, however, the Board considers that the rate charged to BCH for Fort Nelson service must be just and reasonable, in accordance with established regulatory principles._

The AESO considers the Board’s findings in Decision 2005-096 to be consistent with the obligations set out in the Act that the AESO must provide system access service to BC Hydro at Fort Nelson, but without a requirement to forecast, build, or satisfy the need for electricity at Fort Nelson.

(b) BC Hydro’s current agreement for system access service at Fort Nelson includes a contract capacity of 38.5 MW, and has been at that level since March 1, 2008. BC Hydro has requested to increase its contract capacity to 75 MW, as discussed in information response BCH.AESO-002 (a).

Monthly non-coincident metered demand for BC Hydro at Fort Nelson averaged 44 MW during 2009, with the annual non-coincident peak of 58 MW occurring in December 2009. Please refer to information response BCH.AESO-012 (d) for additional information.
Topic: Future Recovery of TMR Costs in the Rainbow Area

Reference: Application, Section 4.5.3, page 43

Preamble: The AESO stated that “Rainbow area TMR generation costs would be allocated on an hourly basis using Fort Nelson and Rainbow area hourly loads. The calculation would be based on SCADA (supervisory control and data acquisition) data as revenue meter data is not available for the determination of Rainbow area load.” It stated further that “Based on the frequency and complexity of allocating the TMR generation costs to BC Hydro, the AESO will assess its practices for this charge and consider implementing an automated solution if appropriate and cost effective.”

Request:

(a) What discussions, if any, has the AESO had with BC Hydro about its proposed allocation of these costs? Please provide a summary of the discussions.

(b) What is the approximate cost and timing of implementing an automated solution?

Response:

(a) BC Hydro participated in the AESO’s stakeholder consultation discussed in section 3 (pages 20-22) of the application, including the general stakeholder meetings and the small working group formed to examine the Fort Nelson demand transmission service rate. The working group met three times in June and July of 2009. Discussions included the history of service to Fort Nelson; the AESO’s obligation to serve Fort Nelson; the capital, operating, transmission must-run, and pool price impacts of service to Fort Nelson; and rate design principles for service to Fort Nelson. BC Hydro participated fully in those discussions. The working group did not reach consensus conclusions (which was not the purpose of the working groups) and written notes were not prepared on the working group’s discussions.

(b) The AESO cannot provide an estimate of the cost and timing of an automated solution to allocate TMR generation costs to BC Hydro at Fort Nelson as the scope and requirements for such a solution are unknown. As well, the cost would depend, in part, on other AESO systems that are in use when the automated solution is being considered, while the timing would depend on the specific solution adopted as well as other priorities of the AESO when the automated solution is being considered.
Topic:  
Recovery of Future TMR Costs  

Reference:  
Application, Section 4.5.3, pages 42-44  

Preamble:  
The AESO stated that “Rate FTS currently accommodates TMR generation requirements to support Rainbow area load of 130 MW, which includes Fort Nelson load of 25 MW and Alberta load in the Rainbow area of 105 MW.” It further stated that “Rainbow area load up to 130 MW can be supported by three TMR generators, incremental TMR generation would be the dispatch of a fourth TMR generator in the Rainbow area.”

The AESO also submitted that “the completion of phase 1 of the northwest development, expected in 2012, was forecast to eliminate the requirement for TMR generation in the Rainbow area. However, significant load growth may occur in Fort Nelson, which could again require TMR generation after the northwest development is complete.

The AESO submitted that “…TMR generation costs allocated to BC Hydro as described above should be in addition to the existing voltage control charge.”

Request:  
(a) Does the AESO currently anticipate a significant amount of TMR will be required to provide service to Fort Nelson after the northwest development is complete?

(b) Provide further explanation around why TMR costs should be allocated to BC Hydro (as proposed) in addition to the existing voltage charge. Comment on whether BC Hydro already pays for a level of incremental TMR under rate FTS.

Response:  
(a) At this time the AESO does not anticipate a significant amount of TMR will be required in the Rainbow area (including Fort Nelson) after the northwest Alberta transmission development is complete. However, as discussed in section 4.5.1 (page 40) of the application, there is a significant amount of uncertainty with respect to future load requirements in Fort Nelson. Future TMR requirements in the Rainbow area will depend on load growth in Fort Nelson, load growth in the Rainbow area in Alberta, and alternatives implemented to meet that load growth either in British Columbia or in Alberta.

(b) The AESO considers that the existing voltage control charge represents costs attributable to serving Fort Nelson load that existed at the time Rate FTS was first implemented (as Rate FDS) in 2006 and that was planned for in the northwest Alberta transmission development. Rate FTS currently includes the “postage stamp” voltage control (TMR) charge from Rate DTS. If Fort Nelson load was not expected to grow
substantially in the future, Rate FTS could likely continue unchanged in which case BC Hydro would continue to pay the existing voltage control charge.

The AESO proposes to allocate additional TMR costs to BC Hydro only in proportion to Fort Nelson load in excess of the level that was planned for in the northwest Alberta transmission development. Additional costs will not be allocated to BC Hydro in respect of the load that existed when Rate FTS was first implemented, and so BC Hydro should continue to pay the existing voltage control charge implemented at that time.

BC Hydro pays for a level of incremental TMR under Rate FTS inasmuch as the voltage control charge is a variable charge which includes all costs incurred for TMR generation by the AESO. However, as provided in Tables 5-10 and 5-13 in section 5 of the application, the metered energy forecast for 2010 under Rate DTS is 55,865.5 GWh and under Rate FTS is 16.7 GWh. Under the current Rates DTS and FTS, which have the same voltage control charge, incremental TMR costs would therefore be recovered 99.97% from Alberta market participants and 0.03% from BC Hydro at Fort Nelson.
Topic: Future Capital Costs in NW Alberta

Reference: Application, Section 4.5.4, page 46

Preamble: The AESO submitted that “a northwest Alberta transmission development would be required to accommodate Fort Nelson load growth. Transmission system developments, by their nature, generally accommodate regional needs over multiple areas. The AESO therefore considers that a methodology should be established to share capital costs appropriately between Fort Nelson, B.C. and Alberta in a fair and objective manner.”

Request:

(a) Are similar methodologies to share capital costs used by the AESO and BC Hydro in other parts of Alberta?

(b) Are similar methodologies applied in reverse, where BC Hydro may be serving load in Alberta?

(c) If other methodologies have been employed, please describe the methodologies and the differences.

Response:

(a-b) No, the AESO’s proposed approach is not used for other BC loads served from Alberta or for Alberta loads served from BC. The AESO is not aware of other locations where a load in one province is served from the transmission system in the other province.

(c) The AESO understands that other loads served from the electric system of the neighbouring province are served at distribution voltages rather than as transmission services. At distribution voltage, service is generally provided at the electricity supplier’s (that is, the distribution utility’s) rate in effect for the applicable class of service in the province from which the electricity is supplied. The AESO is not aware of cases where such service would have resulted in the electricity supplier incurring significant operating or capital costs in respect of providing service to load in the other province.
AUC.AESO-007 (a-b)

Topic: DOS Rates

Reference: Application, Section 4.6, pages 47-49, Table 5-9

Request:

(a) Please explain the rationale for allocating 50 percent of the DTS (per MW/h equivalent) allocation of bulk system fixed costs and 50 percent of the DTS (per MW/h equivalent) allocation of local system fixed costs to the DOS 1 Hour rate.

(b) In consideration of the proposed 50 percent allocations of fixed bulk and local system costs for the DOS 1 Hour rate, please explain the rationale for allocating 100 percent of the fixed bulk and 1200 percent of fixed local costs to the DOS Term rate.

Response:

The allocation of costs to Rate DOS 1 Hour and DOS Term 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. 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 in the information request.

(a) The charge for Rate DOS 1 Hour in the proposed 2010 tariff has been based on the 2007 tariff calculation methodology which, as summarized above, was designed to provide a specific level of increase over the prior charge for Rates DOS 1 Hour. In effect, the charge in the proposed tariff reflects the historical basis for Rate DOS 1 Hour.

Rate DOS 1 Hour includes a contribution towards bulk system and local system fixed costs reflecting the longer recall directive response time and higher recall priority of DOS 1 Hour service compared to DOS 7 Minutes service. The 50% contribution was considered reasonable in the AESO's 2007 tariff refiling as it resulted in similar increases to both DOS 7 Minutes and DOS 1 Hour, compared to the then-existing charges. The 50% contribution represents a minimal amount as Rate DOS includes no contract capacity or ratchet-based charges in hours in which DOS 1 Hour capacity is not requested.
(b) Like the charge for Rate DOS 1 Hour, the charge for Rate DOS Term in the proposed 2010 tariff has been based on the 2007 tariff calculation methodology which, as summarized in the opening paragraphs of this response, was designed to provide a specific level of increase over the prior charge for Rates DOS Term. In effect, the charge in the proposed tariff reflects the historical basis for Rate DOS Term.

The higher contribution of DOS Term service towards bulk system and local system fixed costs reflects the higher priority of DOS Term service compared to DOS 1 Hour service. 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.

DOS Term is also the only type of Rate DOS that is available for scheduled maintenance of a generating unit. Rate DOS Term is therefore priced to ensure it costs at least as much as Rate DTS if used for more than the typical two to four weeks required for annual generator maintenance, including the impact of the 24-month ratchet applicable to the local system charge under Rate DTS.
Topic: XOS Rates - Contribution to Fixed Component of System Charges

Reference: Application, Section 4.7.1, pages 50-51, Table 5-9

Request:

(a) Please explain the rationale for allocating 20 percent of the DTS (per MW/h equivalent) allocation of bulk system fixed costs and 20 percent of the DTS (per MW/h equivalent) allocation of local system fixed costs to the XOS 1 Hour rate.

(b) In consideration of the proposed 20 percent allocations of fixed bulk and local system costs for the XOS 1 Hour rate, please explain the rationale for allocating 30 percent of the fixed bulk and local costs to the XOS 1 Month rate.

Response:

The allocation of costs to Rates XOS 1 Hour and XOS 1 Month 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 XOS 1 Hour rate to provide an increase of 10% over the then-existing Rate EOS charge. The AESO also refiled the XOS 1 Month rate to provide an increase of 20% over the then-existing Rate EOS charge. The XOS 1 Hour and XOS 1 Month rates included contributions to fixed costs which resulted in the increases of 10% and 20%, respectively, compared to the then-existing Rate EOS charge. 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 in the information request.

(a) The charge for Rate XOS 1 Hour in the proposed 2010 tariff has been based on the 2007 tariff calculation methodology which, as summarized above, was designed to provide a specific level of increase over the prior charge for Rate EOS. In effect, the charge in the proposed tariff reflects the historical basis for prior export opportunity rates.

Rate XOS 1 Hour includes a small contribution towards bulk system and local system fixed costs reflecting the lower recall priority of XOS 1 Hour service compared to domestic services and XOS 1 Month service. The 20% contribution was considered reasonable in the AESO’s 2007 tariff refileing as it resulted in a 10% increases to Rate XOS 1 Hour charges, compared to the then-existing charges. The 20% contribution represents a minimal amount as Rate XOS includes no contract capacity or ratchet-based charges in hours in which XOS 1 Hour interchange transactions are not scheduled.
Like the charge for Rate XOS 1 Hour, the charge for Rate XOS 1 Month in the proposed 2010 tariff has been based on the 2007 tariff calculation methodology which, as summarized in the opening paragraphs of this response, was designed to provide a specific level of increase over the prior charge for Rate EOS. In effect, the charge in the proposed tariff reflects the historical basis for prior export opportunity rates.

The somewhat higher contribution of XOS 1 Month service towards bulk system and local system fixed costs reflects the somewhat higher priority of XOS 1 Month service compared to XOS 1 Hour service. As discussed in section 4.7 (page 49) of the application, Rate XOS 1 Month is not yet available as the AESO has not yet implemented the open access same-time information system (OASIS) or similar system that is required to manage the scheduling of multiple export rates.
AUC.AESO-009 (a-f)

Topic: XOS Rates – Allocation of Operating Reserve Charge

Reference: Application, Section 4.7.1, pages 51-52, Appendix H

Request:

(a) Please confirm that the allocation of operating reserves XOS rates is to be applied on an hourly basis, consistent with the hourly allocation of operating reserves proposed for rate DTS. If this cannot be confirmed, please explain.

(b) In consideration of your response to part (a) above, is it the AESO’s intention to deduct hourly operating reserve costs allocated to exports from the operating reserves costs allocated to DTS rates in respect of the same hour?

(c) Please provide an expanded explanation as to why no operating reserve costs are allocated to export service when the contingency reserve requirement is set by the single largest generator contingency.

(d) In paragraphs 249 and 250, the AESO indicates that it detected certain errors in an analysis prepared by TransCanada during the AESO’s 2007 tariff proceeding. Please provide a more complete description of the errors the AESO believes to have been made in TransCanada’s 2007 proceeding analysis.

(e) In consideration of your response to part (d) above, please describe what changes were adopted by the AESO to correct the errors purported to exist in TransCanada’ 2007 proceeding analysis.

(f) In consideration of the AESO’s claim that after correcting the purported TransCanada errors, a 47 percent allocation of the DTS operating charge would be warranted using 2006 data, please explain why it should be considered preferable to use the 32 percent allocation prepared using 2008 data considering the apparent variability of the allocation?

Response:

(a) Not confirmed. Rate XOS is an opportunity service rate. In general, opportunity services need certainty of price to allow market participants to be able to assess the opportunity costs of a transaction to determine whether to make the transaction or not. Rate XOS, like Rate DOS, is therefore offered at a fixed $/MWh price, and is also not subject to retrospective deferral account reconciliation.

(b) No. The revenue from Rate XOS (including its operating reserve component but excluding losses) is a general offset to Rate DTS costs, as shown in Table 5-2 in section 5 of the application. Rate XOS revenue (excluding losses) is forecast to be $1.3 million in 2010, which represents only 0.15% of the AESO’s Rate DTS revenue.
requirement, and the AESO considers that more detailed treatment in the rate calculations is not warranted.

(c) As discussed in Section 4.7.1 (pages 51-52) of the application, the AESO’s contingency reserve requirement in an hour is generally determined as the greater of:

(i) the sum of 5% of Alberta’s firm load responsibility served by hydro and wind generation and 7% of Alberta’s firm load responsibility served by thermal generation, where exports are included in the firm load responsibility for contingency reserve sharing requirements applicable to the AESO as a member of the Northwest Power Pool Reserve Sharing Group; and

(ii) Alberta’s single largest generator contingency.

It follows that at a minimum the AESO is required to carry a contingency reserve equal to the output of the largest generator on the system. This requirement is independent of the volume of the exports. Under the incremental approach approved for the AESO’s 2007 tariff and proposed to be continued in its 2010 tariff, operating reserve costs are allocated to exports only when caused by incremental export volumes. Exports do not cause any incremental reserves when the contingency reserve requirement is set by the single largest generator contingency. The AESO would have carried the reserve requirement equal to the output of the largest generator regardless of whether exports occurred in that hour or not.

(d) The AESO initially tried to replicate the TransCanada analysis based on the description provided in TransCanada’s evidence (section III. D) vi), page 42) filed in the AESO’s 2007 tariff proceeding:

TransCanada undertook an analysis of 2006 export transactions to determine what additional operating reserves were actually incurred. Every hour was examined to identify the amount of spinning reserve in excess of the largest contingency on the system. Since the AESO must purchase operating reserves for the largest contingency regardless of exports, only exports which increase the load to a point where extra operating reserves are required should be considered in an incremental cost analysis. While not all spinning reserves in excess of the largest contingency are required because of exports, TransCanada has adopted this conservative assumption. Even with this assumption, TransCanada found that only 9% of the export energy will potentially be required for spinning reserves. TransCanada has assumed that 9% is also a reasonable estimate of the requirement for supplemental and regulating reserves.

The AESO was unable to match the 9% number determined by TransCanada, and accordingly requested and received from TransCanada the analysis it had performed. The AESO identified the following errors in TransCanada’s analysis.

(i) TransCanada’s analysis did not include wind generation in calculating the contingency reserve requirement. It had therefore understated the contingency reserve requirement by comparing 5% of hydro and 7% of thermal generation to the largest generator contingency.
(ii) TransCanada calculated a ratio of allocated export reserve requirements to total export volumes and applied that ratio to the Rate DTS operating reserve charge. But the ratio of reserve requirement to volume simply reflects the contingency reserve requirement as provided in part (c) above — namely, the greater of 5% of hydro and wind and 7% of thermal generation, or the largest generator contingency. The calculation of any firm load reserve requirement should be in the 5% to 7% range, or lower if hours are excluded when the largest generator contingency sets the requirement. TransCanada’s value was larger than 7% because of the simplifying assumption that all reserves in excess of the largest generator contingency should be allocated to exports.

TransCanada’s calculation could be corrected in two ways. In one approach, operating reserve costs would be allocated to the reserve volumes calculated for exports and domestic loads, the costs would then be respectively divided by the volumes for exports and domestic loads, and finally the resulting charges would be compared to each other to establish the percentage of the Rate DTS operating reserve charge that should be included in Rate XOS.

The AESO took the simpler approach of dividing the reserve volumes by the volumes for exports and domestic loads respectively, and then comparing the two results to establish the percentage amount. Both approaches give the same result.

TransCanada’s calculation significantly understated the percentage of the Rate DTS operating reserve charge that should be included in Rate XOS as it did not compare the Rate XOS reserve allocation to the Rate DTS reserve allocation.

(iii) As noted by TransCanada in its evidence, its calculation assumed “all spinning reserves in excess of the largest contingency are required because of exports.” The AESO has corrected this assumption such that in an hour when the contingency reserve requirement is established by the sum of 5% of hydro and wind generation and 7% of thermal generation, reserves are allocated proportionately to export volumes and domestic load volumes in that hour. TransCanada’s calculation had conservatively overstated the percentage of reserve volumes allocated to exports, but the overstatement was more than offset by the understatements discussed in parts (d)(i) and (d)(ii) above.

(iv) Finally, TransCanada’s calculation excluded behind-the-fence generation when calculating the 7% of thermal generation in the contingency reserve calculation. The AESO’s contingency reserve calculation includes behind-the-fence generation used to serve firm load, and excluding such generation understated the contingency reserve requirement by comparing a smaller calculated requirement to the largest generator contingency.

The AESO notes its own calculation provided as Appendix H to its application also repeated that error.

(e) The AESO has corrected the errors discussed in part (d) above as follows.

(i) The calculated contingency reserve requirement includes all three generation sources: hydro, wind, and thermal.
(ii) The reserve volumes allocated to exports are divided by the export volumes, and
the reserve volumes allocated to domestic loads are divided by the domestic load
volumes. The ratio of these two amounts provided the percentage of the
Rate DTS operating reserve charge that should be included in the Rate XOS
charge.

(iii) In an hour when the contingency reserve requirement is established by the sum
of 5% of hydro and wind generation and 7% of thermal generation, reserves are
allocated proportionately to export volumes and domestic load volumes in that
hour.

(iv) Behind-the-fence generation is included such that the contingency reserve
calculation is based on the total firm load used in the determination of the
AESO’s contingency reserve requirement. The AESO notes that this error was
not corrected in Appendix H as filed with its application, and has been corrected
in the revised Appendix H provided with these information responses.

(f) In general, the AESO believes that recent data should be more representative of a
forecast year than older data. The use of 2006 data in the calculation for the AESO’s
2007 tariff application was consistent with this approach. The AESO had used 2008 data
in the calculation for its 2010 tariff application as was the most recent data available
when Appendix H was prepared. Data for 2009 has since become available, and the
AESO has provided its corrected analysis (discussed in part (e) above) for all four years
(2006, 2007, 2008, and 2009) in the revised Appendix H provided with these information
responses.

Variability of load, exports, natural gas and pool price, transmission system events, and
other factors all affect the timing, volume, and cost of operating reserves. The AESO
continues to support the use of recent data in the calculation of the operating reserve
charge included in Rate XOS. Based on 2009 data, 42% of the Rate DTS operating
reserve charge should be included in Rate XOS. This amount has been reflected in the
revised section 5 rate calculations provided with these information responses.

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.
The allocation of operating reserve costs to Rate XOS may be included as part of that
review.
Topic: Amortized Construction Contribution Rider I

Reference: Application, Section 4.16, page 58

Preamble: At page 58 of the Application, the AESO stated “The development of Rider I was prompted by concerns expressed by market participants in recent years regarding the payment of construction contributions for system access service connections. The concerns reflected changes to legislation and the AESO’s tariff which have increased the frequency and amount of contributions, the magnitude of costs (and associated contributions) when projects require significant connection facilities, and the extended time required for development and construction of some projects.”

Request:

Please comment on whether the revisions to the AESO’s customer contribution policy described in Section 6.11 of the Application would, if adopted, address the concerns noted in the preamble and reduce the need for Rider I.

Response:

No, the AESO does not expect that the revisions to the AESO’s contribution policy will reduce the need for Rider I.

As explained in section 6.11 of the tariff application:

…the AESO in this application is proposing to generally continue the contribution policy approach established in its 2007 tariff proceeding.

Rather than change the approach to the contribution policy, the goals of the proposed revisions to the contribution policy in this application are to increase clarity and reduce subjectivity in the classification of connection project costs, and to produce construction contribution results that are more consistent and more predictable by the market participant. [paragraphs 458-459]

The AESO is proposing an increase to the maximum investment level in the tariff (discussed in section 6.11.7 of the application) consistent with the increase in project costs since the AESO’s 2007 tariff application, and is also proposing staged contribution payments (discussed in section 6.8 of the application) that may address concerns with the extended time required for some projects. However, the AESO expects that the frequency and amount of contributions and the magnitude of costs required for connection projects will continue to be concerns of market participants. The AESO accordingly expects that the concerns noted in the preamble will continue to exist and that the changes proposed to the contribution policy will not materially reduce the need for Rider I.
Topic: Amortized Construction Contribution Rider I

Reference: Application, Section 4.16, page 60

Preamble: At page 58 of the Application, the AESO stated “Since the financial impact is attributed to the market participant who elects Rider I, the AESO suggests it is reasonable to allow a market participant to “convert” a construction contribution to an amortized payment under Rider I at any time. The amount converted would be the balance which would have remained unamortized at the time of conversion, if the full contribution had been amortized for the project initially. The AESO proposes a market participant may convert to an amortized payment only once, to avoid excess administration of Rider I amounts and to prevent opportunities to “game” differences between the tariff discount rate and short-term financing costs applicable to the market participant.”

Request:

(a) Please explain why the AESO is proposing to allow customers with outstanding construction contribution balances to convert to an amortized Rider I payment rather than restricting the applicability of Rider I to new connections only.

(b) What amount of current contribution balances does the AESO expect to be converted into Rider I payments?

Response:

(a) The AESO proposes that existing market participants should be allowed to convert outstanding contribution balances to amortized payments under Rider I for two reasons.

First, the AESO considers it reasonable to allow market participants to convert new construction contributions to amortized payments under Rider I at any time after commercial operation. The AESO understands that a market participant may not initially appreciate the impact of converting a construction contribution to Rider I payments and anticipates that conversion requests will occasionally occur some time after commercial operation, at least when Rider I first becomes available. As the market participant’s Rider I payments will include all costs associated with the amortized contribution, and as the administration of a conversion is expected to remain the same regardless of when it occurs, the AESO cannot see a justification to refuse conversions anytime after commercial operation. If later Rider I conversions are reasonable for new contributions, then they should also be reasonable for existing contributions. The AESO considers it both equitable and non-discriminatory to allow later conversions to Rider I payments for market participants with existing outstanding contribution balances as well as for those paying new construction contributions.
Second, as discussed in section 4.16 (pages 58-59) of the application, Rider I approaches were proposed in ATCO Electric's 2009-2010 general tariff application and in AltaLink’s 2009-2010 TFO tariff application as an alternative to the management fees included in those applications. Approvals for the management fees were requested based on levels of contributions in aid of construction expected to be held by ATCO Electric and AltaLink at the end of 2010 (as discussed in part (b) below). If the market participants who paid those contributions for transmission connection projects were not allowed to convert the contributions to amortized payments under Rider I, the AESO expects the level of transmission contributions would continue to be a concern of ATCO Electric and AltaLink. The AESO’s Rider I proposal would therefore be less effective in helping address interveners’ concerns with the TFO management fee proposals, if existing outstanding contribution balances could not be converted to Rider I payments.

(b) The AESO has not prepared an assessment of the amount of current construction contribution balances that might be converted into amortized payments under Rider I. Recent TFO tariff applications and filings have included a total balance of about $261 million of unamortized contributions in aid of construction as summarized below.

<table>
<thead>
<tr>
<th>TFO</th>
<th>Contributions $ 000 000</th>
<th>Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>AltaLink</td>
<td>$103.7</td>
<td>AltaLink 2009-2010 TFO Tariff Refiling — Forecast 2010 Mid-Year Balance</td>
</tr>
<tr>
<td>ATCO Electric Transmission</td>
<td>124.0</td>
<td>ATCO Electric 2009-2010 GTA Refiling — Forecast 2010 Mid-Year Balance</td>
</tr>
<tr>
<td>EPCOR Transmission</td>
<td>25.7</td>
<td>EPCOR 2010-2011 Tariffs Application — Forecast 2010 Mid-Year Balance</td>
</tr>
<tr>
<td>Lethbridge Transmission</td>
<td>1.7</td>
<td>Lethbridge 2009-2011 TFO Tariff Refiling — Forecast 2010 Mid-Year Balance</td>
</tr>
<tr>
<td>TransAlta Transmission</td>
<td>0.1</td>
<td>TransAlta 2009-2010 TFO Tariff Refiling — Forecast 2010 Mid-Year Balance</td>
</tr>
<tr>
<td><strong>Total Contributions</strong></td>
<td><strong>$261.2</strong></td>
<td></td>
</tr>
</tbody>
</table>

This $261 million balance would represent an upper limit for the existing contributions that could be converted to Rider I payments. The AESO has no information on which to base an expectation of how much of this balance might actually be converted if Rider I is approved as filed. The AESO understands that market participants generally support the AESO’s proposed Rider I, but any who commented on whether they would convert existing contributions indicated it would depend on the final Rider I details that are approved as well as analysis of several factors, including financing costs applicable to the individual market participant and other opportunities for capital investment available to the market participant.
Topic: Wind Forecasting Service Cost Recovery Rider J

Reference: Application, Section 4.17, page 63

Preamble: The AESO noted that “Rider J is an exception to its normal tariff charges, as legislative requirements appear to have little applicability to the recovery of these costs. … Rather, it is a cost related to a service which can be arranged and managed by the wind generators themselves, but which can be more effectively and efficiently arranged and managed by the AESO.”

Request:

Please comment on whether the wind forecasting costs can be allocated to wind generation in view of Section 47 of the Transmission Regulation.

Response:

Section 47 of the Transmission Regulation was provided in section 4.1 of the AESO’s application, and is repeated here for convenience:

ISO tariff - transmission system considerations
47 When considering an application for approval of the ISO tariff under sections 121 and 122 of the Act, the Commission must
(a) ensure
   (i) the just and reasonable costs of the transmission system are wholly charged to DFOs, customers who are industrial systems and persons who have made an arrangement under section 101(2) of the Act, and exporters, to the extent required by the ISO tariff, and
   (ii) the amount payable by a DFO is recoverable in the DFO’s tariff,
(b) ensure owners of generating units are charged local interconnection costs to connect their generating units to the transmission system, and are charged a financial contribution toward transmission system upgrades and for location-based cost of losses, and
(c) consider all just and reasonable costs related to arrangements and agreements described in section 9(5) of the Act.

As the AESO noted in the application excerpt quoted in the preamble, legislative requirements appear to have little applicability to the recovery of wind forecasting service costs. In particular, section 47 of the Transmission Regulation deals with:
(a) costs of the transmission system;
(b) local connection costs, financial contributions toward transmission system upgrades, and location-based cost of losses; and
(c) costs related to arrangements and agreements with responsible authorities in jurisdictions outside Alberta.

The transmission system, as defined in section 1(1)(ccc) of the Act, means “all transmission facilities in Alberta that are part of the interconnected electric system.” A transmission facility, as defined in section 1(1)(bbb) of the Act, means:

…an arrangement of conductors and transformation equipment that transmits electricity from the high voltage terminal of the generation transformer to the low voltage terminal of the step down transformer operating phase to phase at a nominal high voltage level of more than 25 000 volts to a nominal low voltage level of 25 000 volts or less, and includes

(i) transmission lines energized in excess of 25 000 volts,

(ii) insulating and supporting structures,

(iii) substations, transformers and switchgear,

(iv) operational, telecommunication and control devices,

(v) all property of any kind used for the purpose of, or in connection with, the operation of the transmission facility, including all equipment in a substation used to transmit electric energy from

(A) the low voltage terminal,

(B) electric distribution system lines that exit the substation and are energized at 25 000 volts or less,

and

(vi) connections with electric systems in jurisdictions bordering Alberta, but does not include a generating unit or an electric distribution system;

The wind forecasting service is clearly not a transmission facility and therefore not part of a transmission system. The wind forecasting service costs are accordingly not addressed in section 47(a) of the Transmission Regulation.

As explained in the application, the wind forecasting service is a centralized service. It is not a cost arising from the local connection of a generating unit, and it is also not a cost of a transmission system upgrade or a location-based cost of losses. The wind forecasting service costs are therefore similarly not addressed in section 47(b) of the Transmission Regulation.

Finally, the wind forecasting service does not relate to arrangements or agreements with responsible authorities in jurisdictions outside Alberta as described in section 9(5) of the Act. The cost of the service is therefore not addressed in section 47(c) of the Transmission Regulation.

In conclusion, section 47 of the Transmission Regulation provides no guidance with respect to the treatment of wind forecasting service costs, as such costs are not included in the costs addressed in that section. Section 47 neither prevents, nor explicitly enables, the allocation of wind forecasting service costs to wind generators as contemplated in the proposed Rider J.
Topic: Wind Forecasting Service Cost Recovery Rider J

Reference: Application, Section 4.17, page 63; Table 4-11, page 64

Preamble: The AESO submitted that “For reasons of predictability and simplicity, wind forecasting service costs should be recovered based on energy production – that is a $/MWh charge.”

Request:

The wind forecasting service appears to be a fixed cost please explain the AESO’s rationale for charging that cost on a $/MWh basis rather than as a fixed charge allocated on a per MW basis.

Response:

As explained in section 4.17 of the application (page 63, paragraph 319), “[T]he cost of the forecasting service does not vary to any great extent with the number, installed capacity, or production of wind generators.”

The cost causation principle which underlies the AESO’s rate design is discussed in section 4.2 (page 28, paragraph 127) of the application, and is satisfied “by rates which recover costs in the manner in which they are caused.” Since the wind forecasting service costs are not caused by the number of customers, capacity (MW), or production (MWh), there is no cost causation basis for the charge. The AESO accordingly relied on other considerations for the design of Rider J.

These considerations were summarized in section 4.17 (page 63, paragraph 320) of the application and are as follows:

(i) reasons of predictability and simplicity, as $/MWh production charges are consistent with other system access service charges to wind generators under Rate STS;

(ii) avoidance of concerns that arise with a $/MW capacity charge if a generator’s capacity is curtailed due to system constraints or if the generator incurs capacity outages for other reasons beyond its control;

(iii) consideration of the greater value the wind forecasting service provides to a larger generator; and

(iv) consideration of the value the wind forecasting service provides by allowing greater wind generation production to be accommodated on the transmission system.

The AESO also reviewed these considerations with wind generators in a stakeholder consultation process in mid-2009, and cost recovery on a $/MWh basis was generally supported by participants in that process.
Based on the considerations summarized above and on stakeholder support, the AESO concluded that recovery of the wind forecasting service costs as a $/MWh charge based on energy production was a more reasonable and appropriate approach than either recovery as a $/month charge based on number of wind generators or as a $/MW charge based on capacity.
**Topic:** Removal of Article 20

**Reference:** Application, Section 6.1 Tariff Change Related to the Transition of Authoritative Documents (TOAD) Project, page 95

**Preamble:** The AESO indicated that it was “…finalizing a single set of confidentiality provisions that will apply consistently to all information exchanged with the AESO.” Given that the AESO is proposing to completely remove Article 20 from the ISO Tariff, the Commission wishes to understand when the single set of confidentiality provisions will be finalized and reside within the ISO rules.

**Request:**

(a) Please confirm if a single set of confidentiality provisions is currently developed to replace Article 20. If so, please provide a copy.

(b) If not, please indicate when the AESO anticipates the single set of confidentiality provisions will be finalized.

**Response:**

(a-b) Confirmed. The AESO has developed a single set of confidentiality provisions and has represented those provisions in ISO Rule 103.1. The final proposed ISO Rule 103.1 was filed with the Commission on April 6, 2010 and no objections were received on this rule. The rule comes into effect on April 30, 2010.

Please see Attachment AUC.AESO-014 for a copy of ISO Rule 103.1.
Topic: Timing of the Completion of the TOAD Project

Reference: Application, Section 6.1 Tariff Change Related to the Transition of Authoritative Documents (TOAD) Project, page 96

Preamble: The AESO noted that “the TOAD project is still in an early phase of development.”

Request:

(a) Please provide a project timeline for the TOAD project.

(b) Does the AESO anticipate removal of more than Articles 12, 18, 19 and 20 from the ISO Tariff as a result of the TOAD project?

(c) Please provide an estimate of the number of subsequent revisions that will be required to the content of the tariff as a result of the TOAD project.

(d) Please comment on how the TOAD project affects the AESO’s duty to file a tariff containing the terms and conditions that apply to each class of system access service pursuant to section 30(1)(b) with the Commission and on the Commission’s duty to approve that tariff.

(e) What criteria has the AESO applied when it removed provisions from the AESO tariff?

Response:

(a) The target completion date for the TOAD project is mid-2012.

(b) No, the AESO does not expect to remove further sections (or Articles in the 2007 tariff) in their entirety throughout the remainder of the TOAD project.

(c) The AESO continues to review the tariff and identify potential revisions to subsections of the tariff consistent with the TOAD objectives of elimination of duplication and consolidation of related subject matter, where possible, into one of the authoritative domains of ISO rules, ISO tariff, or Alberta Reliability Standards. The AESO currently considers that the following three tariff sections may be impacted through the remainder of the TOAD project, depending on recommendations and conclusions reached as the AESO reviews its authoritative documents.

(i) Section 3 — System Access Service Connection Requirements

First, the AESO is transitioning the authoritative provisions of the technical connection requirements to ISO rules. Once the transition is complete, the ISO
tariff provisions that require compliance with those requirements must be removed to eliminate duplication with ISO rules.

Second, the AESO is reviewing the development of an ISO rule setting out the requirements and obligations of market participants with respect to the connection queue. If a connection queue rule is developed, amendments to the language in section 3 will probably be required.

Finally, as part of the TOAD project all non-binding and procedural information will be set out in an information document. The creation of information documents related to the connection requirements will lead to amendments to the language in section 3 to potentially refer to the information documents and remove references to guidelines and other documents, as appropriate.

(ii) **Section 6 — Metering**

The AESO is transitioning the authoritative provisions of the *AESO Measurement System Standard* to ISO rules. Once the transition is complete, the ISO tariff provision that requires compliance with that standard must be removed to eliminate duplication with ISO rules.

(iii) **Section 7 — Provision of Information By Market Participants**

The AESO requires various types of information from all market participants, not only those market participants receiving system access service under the ISO tariff. Consistent with Commission Decision 2008-108 on Transmission Facility Owner Terms and Conditions, the AESO will proceed with consolidation and representation of information and data in ISO rules. As part of this work the AESO will review section 7 of the proposed tariff and will consolidate information requirement provisions or remove duplicate requirements, as appropriate.

The AESO does not expect that the creation of the ISO rules and information documents discussed above will be complete prior to the close of record in the 2010 ISO tariff proceeding. As well, continuation of the review and assessment of authoritative documents through the TOAD project may indicate other sections of the ISO tariff should be revised, as discussed in section 6.1 (page 96) of the application. At this time the AESO cannot estimate the timing of such revisions. The AESO will coordinate revisions and amendments to the tariff as much as possible, to reduce the number of applications which the Commission must review.

(d) **The TOAD project will not affect the AESO’s duty to submit to the Commission a tariff setting out the terms and conditions that apply to each class of system access service, pursuant to section 30(1)(b) of the *Electric Utilities Act*, nor with the Commission’s duty to approve that tariff.**

The TOAD project includes the review and assessment of related subject matter across the authoritative domains of ISO rules, ISO tariff, and Alberta Reliability Standards with a view towards consolidating related subject matter and eliminating duplication. Authoritative documents in each of those domains must satisfy applicable development, filing, and review requirements. Consistent with past tariffs, the proposed 2010 ISO tariff continues to reference ISO rules where appropriate. The AESO expects that the
Commission, as part of its approval process, will ensure that references to ISO rules in the tariff are reasonable and not unduly preferential or arbitrary, in accordance with section 121(1) of the *Electric Utilities Act*.

(e) The AESO considered four key principles when it determined if a provision should be proposed to be removed from the ISO tariff.

(i) In accordance with section 20 of the *Electric Utilities Act*, does the AESO have the authority to make rules respecting the subject matter of the provision?

(ii) In accordance with section 30 of the *Electric Utilities Act*, is the AESO obligated to represent the subject matter of the provision in the ISO tariff?

(iii) Is the subject matter of the provision binding or authoritative in nature, or is it informational or procedural in nature?

(iv) Does the subject matter of the provision apply only to market participants connected to the transmission system and receiving system access service, or does the provision apply to a broader set of market participants?
Topic: Processes related to the Consolidated Authoritative Documents Glossary

Reference: Application, Section 6.3 Definitions, page 97

Preamble: “The Consolidated Authoritative Documents Glossary will exist as a standalone document and will contain defined terms that have been approved through the regulatory processes applicable to the ISO tariff, ISO rules and the Alberta reliability standards. As terms are approved, they will be added to the glossary.”

Request:

(a) Please confirm if the Consolidated Authoritative Documents Glossary currently exists. If so, please provide a copy.

(b) Please describe the process by which defined terms will be updated, added to or deleted from the glossary.

(c) Is it the AESO’s intention that once a term is defined, that it will be applied equally to all rules? If yes, does the AESO anticipate that a one-term-fits-all approach will face any practical difficulties when applying one term to different rules? If so, how will this be resolved?

(d) Please confirm that insofar as an amendment to the Consolidated Authoritative Documents Glossary affects the AESO’s tariff, an application will be made to the Commission to amend the tariff. Please comment on when the amendments will be effective insofar as they relate to the tariff.

Response:

(a) The Consolidated Authoritative Documents Glossary is currently being complied but has not yet been published. The AESO expects the initial version of the glossary will be published in early May 2010.

(b) Defined terms will be updated, added, or deleted from the glossary after the terms have been developed, filed, and reviewed in accordance with requirements for the authoritative domain of ISO rules, ISO tariff, or Alberta Reliability Standards in which the defined term is used. Those requirements are set out, respectively, in section 20 of the Electric Utilities Act, section 30 of the Electric Utilities Act, and section 19 of the Transmission Regulation.

Once the review process in complete and a defined term has been confirmed, the AESO will update the Consolidated Authoritative Documents Glossary and publish the new version on the AESO’s website. For clarity, the Consolidated Authoritative Documents Glossary will not be filed with the Commission for approval or confirmation, but all defined terms contained in the glossary will have been developed, filed, and reviewed in
accordance with applicable requirements for the ISO rules, ISO tariff, or Alberta Reliability Standards.

(c) It is the AESO’s intention to use defined terms consistently in the ISO rules, ISO tariff, and Alberta Reliability Standards, where appropriate. However, any defined term used in an authoritative document will need to have been developed, filed, and reviewed in accordance with applicable requirements for the authoritative domain which that document is part of (that is, for the ISO rules, ISO tariff, or Alberta Reliability Standards).

As well, in some circumstances different defined terms may be necessary to address discrete subject matter in different authoritative domains or documents. In these instances the AESO will create a unique defined term which will be subject to the same development, filing, and review processes discussed in part (b) above. Such unique defined terms will only be created where it is necessary to avoid confusion and potential conflict with other defined terms.

The AESO notes that some legacy defined terms currently exist which need to be amended to eliminate unnecessary variations and duplication.

(d) Confirmed. The AESO has filed both new defined terms and amended existing defined terms as part of its 2010 ISO tariff application, consistent with its usual practice of updating defined terms used in the tariff as part of tariff applications. The AESO does not currently anticipate amending the defined terms included in the 2010 ISO tariff application.

If amendments to defined terms in the tariff are required in the future, the AESO expects such defined terms would become effective on a date consistent with the effective date of any other tariff changes approved at that time. If the amendments to defined terms do not relate to any other tariff changes, the AESO expects such amendments could become effective immediately on their approval in a Commission decision, subject to other considerations such as coordination with changes to other authoritative documents or time for market participants to prepare for any impacts from the amendment to the defined term.

The AESO notes that, as part of the TOAD process, it has filed amendments to certain defined terms in the ISO rules to align those terms with terms in the SIO tariff. The amendments to defined terms in the ISO rules were filed with the Commission on December 1, 2009 and referred to as “Package #1 Definition Changes”. The AESO has proposed that the effective date for the amendments for those defined terms in the ISO rules should align with the effective date for the corresponding changes to the defined terms in the ISO tariff.
Topic: Response to Information Requested by the AESO

Reference: Application, Section 6.10 Provision of Information by Market Participants (Section 7), page 107

Preamble: The AESO proposed that “… the current requirement for forecast information to be provided on October 1 of each year be revised to a requirement that it be provided in response to a request from the AESO, but not more than once in a 12-month period.”

Request: How much notice will the AESO give to market participants to provide forecast information?

Response: The AESO requests that forecast information be provided by the market participant within 30 days of the request.
Topic: Facilities in Excess of Good Electric Industry Practice

Reference: Application, Section 6.11.3, page 114, page 115

Preamble: The AESO indicated that “Since the beginning of 2006, the AESO’s tariff has limited investment to no more that the cost of ‘Standard Facilities’ which were to ‘generally consist of a single radial transmission circuit and a single transformer to supply an individual’ point of delivery or point of supply.”

Request:

(a) Please provide a forecast of the impact that the adoption of the new connection standard will have on AESO rates. Please provide all assumptions used for this forecast.

(b) At page 102, Decision 2007-106 refers the AESO’s response to AE.AESO-003 from the AESO 2007 GTA, which provided hyperlinks to AESO distribution point of delivery process guidelines prepared by the AESO with assistance from DISCOs and TFOs. Please file the documents referenced in 2007 GTA AE.AESO-003 response, or any subsequent updates thereto.

(c) Please comment on the merits of referencing technical standards documents such as the documents referred to in (b) above as the basis for assessing the appropriate facilities for a new connection.

(d) Does the AESO agree that facilities in excess of “Good electricity operating practice” should be assessed in relation to technical standards documents such as those described in part (b)? If not, please fully explain.

(e) Please comment on the concern that permitting each TFO to assess whether connection facilities are in excess of good electric industry practice could lead to the development of inconsistent standards across the province.

(f) In consideration of your response to (e), please describe how the AESO intends to ensure that different TFO connection standards do not evolve.

Response:

(a) The AESO does not expect the proposed removal of the concept of standard facilities to have any effect on rates.

Changes to contribution policy affect the amount of investment in a connection project and the amount of contribution that must be paid by a market participant when the cost of those facilities exceeds the maximum investment available. The amounts of investment and contribution are reflected in the rate base of the TFO who owns the
facilities, and changes in rate base are accordingly reflected in the TFO tariff and in the AESO’s rates which recover the TFO tariffs paid by the AESO.

As discussed in section 6.11.7 (pages 118-119) of the application, the multiplier applied to the connection project cost function was reduced from 1.15 to 1.06 to ensure that total investment in connection projects would not be affected by the removal of the concept of standard facilities. The AESO’s analysis determined that if investment were based on standard facilities costs, a multiplier of 1.15 would be applied to the standard facilities cost function and result in total investment of $440.2 million in the 64 connection projects in the analysis. With removal of the concept of standard facilities, a multiplier of 1.06 was applied to the total cost function to result in total investment of $439.3 million in the same 64 projects. As the total investment is unchanged, there would be no impact on TFO tariffs and no impact on the rates charged by the AESO.

The AESO expects the facilities requested by market participants will not be materially affected by the removal of the concept of standard facilities, as discussed in information response UCA.AESO-008 (a).

(b) Please see the documents provided as Attachment AUC.AESO-018 (b) which include the following Distribution Point of Delivery Interconnection Process Guidelines:
- Evaluation of Transmission versus Distribution Alternatives for Large Customers
- New Point of Delivery Substations
- Typical Supply Arrangements
- Distribution Circuit Breaker Addition
- Drivers of Need
- Economic Evaluation
- Upgrades to an Existing Substation
- Standards of Service

In section 6.6 (page 102 of the application, the AESO notes that it is “currently revising, updating, and adding to these documents as part of its activities related to the TOAD project.” As discussed in information response AUC.AESO-015 (c), the AESO is transitioning the authoritative content of technical requirements to ISO rules, with non-binding and procedural information set out in information documents. The guidelines listed above are non-binding in nature and are expected to be integrated into information documents over the next two years.

(c) The AESO considers that “good electric industry practice” is a commonly referenced standard of practice that includes satisfying applicable technical requirements as well as other considerations that would reasonably and ordinarily be expected to apply in the circumstances.

As well, as discussed in part (b) above, the authoritative content of technical requirements is being transitioned to ISO rules. These requirements will apply as ISO rules to a market participant’s connection and will not need to be enforceable through the ISO tariff. Explicitly referencing the technical requirements in the tariff would result in unnecessary duplication between the ISO rules and ISO tariff.

(d) As discussed in part (c) above, “good electric industry practice” is a commonly referenced standard of practice that includes satisfying applicable technical
requirements as well as other considerations that would reasonably and ordinarily be expected to apply in the circumstances. The standard of practice in the definition of “good electric industry practice” provides for the application of knowledge, skill, diligence, prudence, and foresight which would ensure that all applicable requirements are satisfied, including any technical requirements that exist as ISO rules.

(e-f) As discussed above, “good electric industry practice” is a commonly referenced standard of practice. The criteria which it would be evaluated against are embedded in the definition, namely, “the standard of practice attained by exercising that degree of knowledge, skill, diligence, prudence and foresight which would reasonably and ordinarily be expected from a skilled and experienced person engaged in the same type of undertaking in the same or similar circumstances, including determining what is reasonable in the circumstances having regard to economic considerations.” The AESO understands that “good electric industry practice” and similar standards are utilized in many fields and in such cases are applied consistently and without discrimination. The AESO expects that all TFOs would consistently determine good electric industry practice due, at least in part, to its similarity to the definition of “good electric operating practice” in the transmission terms and conditions under which the TFOs provide service to the AESO.

Also, as discussed in section 6.11.3 (page 115) of the application, investment is more frequently limited by the maximum investment formula than by the standard facilities definition. The standard facilities definition is therefore less important than it may once have been, since regardless of whether facilities are considered “standard” or “in excess of standard” the amount of investment would not change and the market participant would pay the same construction contribution.
Topic: Facilities in Excess of Good Electric Industry Practice

Reference: Application, Section 6.11.3, page 116 and Section 6.11.8, page 122

Preamble: The AESO proposed that “To ensure there is a mechanism to prevent abuse of this removal [standard facilities definition] in the event that investment remains available for a connection, the AESO proposes that the TFO can deem facilities to be in excess of those required by good electric industry practice.”

Request:

(a) Please explain why the AESO considers it to be appropriate that the TFO rather than the AESO should be responsible for assessing whether facilities for a new customer connection are in excess of Good Electric Industry Practice.

(b) In consideration that TFO earn a return on rate base, please explain why the AESO considers that a TFO will be incented to deem facilities to be in excess of those required by good electric industry practice.

Response:

(a) The AESO plans and develops Alberta's transmission system but does not own transmission facilities. The AESO is responsible for preparing a needs identification document describing the timing and nature of the need for a system access service project, and for submitting the document to the Commission for approval.

TFOs, on the other hand, construct, own, and operate transmission facilities. TFOs are responsible for preparing facilities applications for the construction and operation of substations and transmission lines, and for submitting the facilities application to the Commission for permit and licence.

The AESO accordingly considers it appropriate that the TFO make determinations with respect to specific facilities constructed for system access service.

The AESO also considers that “good electric industry practice” is a commonly referenced standard of practice that is familiar to TFOs. In particular, the definition of “good electric industry practice” is similar to that of “good electric operating practice” in the transmission terms and conditions under which the TFOs provide service to the AESO.

(b) The AESO considers that TFOs, as regulated utilities, would comply with requirements and obligations established for them with respect to system access service requests. As discussed in information response AUC.AESO-018 (e-f), the AESO expects that the definition of “good electric industry practice” will be applied consistently to connection projects.
Also, as discussed in section 6.11.3 (page 115) of the application, investment is more frequently limited by the maximum investment formula than by the standard facilities definition in the AESO’s current tariff. In such cases, the market participant pays a construction contribution whether facilities are considered “standard” or “in excess of standard”. A TFO does not earn a return on facilities for which a construction contribution has been paid, so there would seldom be an incentive for a TFO to consider unnecessary facilities to be required by “good electric industry practice” and thereby increase the contribution paid to the TFO. As well, in such a case the increased contribution would be paid by the market participant, and the AESO would expect a market participant to argue that the additional facilities were not required to reduce the construction contribution.
Topic: Operations and Maintenance Charge

Reference: Application, Section 6.11.8, page 121

Preamble: The AESO pointed out that “Decision 2009-105 also determined (paragraph 58) that the operations and maintenance charge should apply ‘only in respect of the cost of facilities which exceed the AESO Standard Facilities built for a new or expanded customer interconnection.’”

Request:

Given the AESO’s request for retroactive treatment to January 1, 2010, will the proposed new provisions have implications around O&M charges for projects that had the previous provisions applied to them? If so, please describe the implications.

Response:

Application of the proposed O&M charge is part of the contribution policy set out in sections 8 and 9 of the proposed 2010 ISO tariff. The proposed O&M charge would therefore become effective on the same date as the rest of sections 8 and 9 of tariff, which the AESO has requested be approved retroactive to January 1, 2010.

The AESO’s current practice is consistent with the provision in subsection 7(1) of section 8 of the proposed tariff, which states, “The construction contribution will be calculated in accordance with the construction contribution provisions of the ISO tariff in effect on the date on which the Commission issues permit and licence for the connection project.”

If the contribution policy in the 2010 tariff is approved to be retroactive to January 1, 2010, any project for which permit and licence is issued on or after January 1, 2010, would be subject to the 2010 contribution policy, including the 2010 O&M charge. Such a project may previously have had a construction contribution determined based on the O&M charge in the AESO’s 2007 tariff, at 12% of the cost of facilities in excess of standard. That project would now have its construction contribution recalculated based on the O&M charge in the AESO’s 2010 tariff, at 14.5% of costs which exceed the investment determined under the 2010 contribution policy. The AESO notes that the maximum investment level under the 2010 contribution policy is higher than under the 2007 contribution policy, and the construction contribution for a specific project may not increase as a result of the increase in the O&M charge.

Any connection project for which the Commission had issued permit and licence between August 1, 2008 and December 31, 2009 would continue to have its construction contribution determined under the provisions of the AESO’s 2007 tariff, and would not be affected by the retroactive approval of the proposed contribution policy.
Topic: Future Transmission Cost Causation Studies

Reference: Application, Section 8.2, pages 261-262

Preamble: On June 9, 2010, the AESO released its 2009 long term transmission system plan. The plan describes forecasted expenditures on direct assign transmission projects totaling to $14.463 Billion in 2008 dollars over the next 10 years.

The Commission wishes to obtain additional information respecting the projects described in the long term plan to assist in understanding their impact on functionalization of transmission wires costs in the future.

Request:

(a) Please file a copy of the AESO’s 2009 long term transmission system plan.

(b) In respect of all capital projects identified in the long term transmission plan, please provide an electronic spreadsheet containing the following information:

- the project name (as named in the long term plan);
- the TFO to which the project is expected to be assigned;
- the expected in-service year for the project;
- the forecast total cost of the project;
- an indication as to whether the project has been designated as Critical Transmission Infrastructure (CTI);
- an initial (rough) estimate of the functionalization of each project’s total cost as between:
  - bulk system costs
  - local system costs
  - POD-related costs

A template showing the expected format for presenting the requested information is provided below for illustrative purposes.

<table>
<thead>
<tr>
<th>Project Name</th>
<th>TFO Name</th>
<th>Expected In-Service Year</th>
<th>CTI Project? (Y/N)</th>
<th>Project Cost ($)</th>
<th>Bulk Portion ($)</th>
<th>Local Portion ($)</th>
<th>POD Cost Portion ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

(c) Does the AESO agree that the relative weighting of capital related and non-capital related costs used for the wires cost functionalization purposes in the AESO’s 2010 GTA should be expected to change from the proposed weighting of approximately 71.4 percent capital / 28.6 percent non-capital to a more capital intensive weighting because non-capital costs are not expected to rise in proportion with the expected increase in
TFO rate base expected to be cause by the capital program described in the 2009 long term plan? If the AESO does not agree, please fully explain.

(d) In consideration of your response to part (c) above, please provide an estimate of the expected weighting of capital/non-capital cost for wires cost functionalization purposes that would be expected by 2014? Please fully describe your assumptions for your estimate.

Response:

(a) Please see Attachment AUC.AESO-021 (a) which is the AESO Long-Term Transmission System Plan 2009.

(b) Please see Attachment AUC.AESO-021 (b) which provides the requested information for capital projects totaling $14,463 million consistent with Table 4.10-1 on page 56 of the AESO Long-Term Transmission System Plan 2009.

Please note that the southern Alberta (wind) transmission system reinforcements (SATR) projects were listed as critical transmission developments in the Long-Term Plan, but are now considered part of the long-term regional transmission plan. SATR is not one of the four critical transmission infrastructure projects included in the schedule attached to the Electric Utilities Act and is not indicated as a CTI project in Attachment AUC.AESO-021 (b).


(c) Agreed.

(d) The AESO estimates that TFO-related capital and non-capital costs will increase from 2010 to 2014 as follows.

(i) **Capital costs** — As part of its development of the long-term plan, the AESO prepared a Microsoft Excel model to calculate the impact of capital projects in the plan on the AESO’s transmission charges. The model (provided as Attachment AUC.AESO-021 (d)) included an estimate of incremental TFO revenue requirement from the $14,463 million of capital projects in the long-term plan over the years 2008-2027. The incremental capital-related revenue requirement was estimated to be $74.9 million in 2010 and $1,031.3 million in 2014, for an increase of $956.4 million from 2010 to 2014.

(ii) **Non-capital costs** — Based on data in the Transmission O&M Cost Workbook filed as Appendix D to the application, non-capital costs increase by about 5.4% per year on average for TFOs. The average 5.4% increase was based on non-capital costs of $119.6 million, $126.4 million, $137.0 million, and $140.0 million in 2006, 2007, 2008, and 2009 respectively, as provided on the “Sum 1.0” sheet in the workbook. An increase of 5.4% per year would result in a total increase in non-capital costs of about 23.4% from 2010 to 2014.
Based on the estimated increases in capital costs and non-capital costs from 2010 to 2014, the AESO estimates the following impact on the capital/non-capital weighting for wires cost functionalization.

<table>
<thead>
<tr>
<th>TFO Wires-Related Costs, $ 000 000</th>
<th>2010 AESO Revenue Requirement</th>
<th>2010 AESO Forecast</th>
<th>Revenue Increase to 2014</th>
<th>2014 AESO Estimate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital Costs</td>
<td>$457.8</td>
<td>$956.4 ¹</td>
<td>$1,414.2</td>
<td></td>
</tr>
<tr>
<td>Non-Capital Costs</td>
<td>183.4</td>
<td>42.9 ²</td>
<td>226.3</td>
<td></td>
</tr>
<tr>
<td>Total Costs</td>
<td>$641.2</td>
<td>$999.3</td>
<td>$1,640.6</td>
<td></td>
</tr>
</tbody>
</table>

Weighting, %  
<table>
<thead>
<tr>
<th>As Filed</th>
<th>Estimated</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital Costs</td>
<td>71.4%</td>
</tr>
<tr>
<td>Non-Capital Costs</td>
<td>28.6%</td>
</tr>
<tr>
<td>Total Costs</td>
<td>100.0%</td>
</tr>
</tbody>
</table>

Notes: ¹ As calculated in part (d)(i) above. ² 23.4% of $183.4 million, where 23.4% is calculated in part (d)(ii) above.

The AESO cautions that this estimate of a 2014 weighting is very approximate. It ignores the effects of capital maintenance, upgrades, replacements, and retirements of existing TFO facilities, contributions received for the POD portions of long-term plan projects, connection projects for market participants, non-capital costs associated with the long-term plan projects, and other factors. However, as agreed to in part (c) above, the estimate illustrates that the long-term plan projects are expected to result in a more capital-intensive weighting of TFO costs in the future.
Topic: System Access Service Requests

Reference: Application, Section 6.7, pages 102-103

Preamble: The AESO submitted that “The new connection model is also inconsistent with the current application fee requirement, as the market participant, rather than the AESO, is responsible for advancing a project through the applicable stages of development. The current application fee, which is refundable upon energization of a connection project, was implemented to discourage the submission of system access service requests that were unlikely to proceed to energization. However, the application fee has not been effective at limiting connection requests to only those for viable projects, and in fact has proved to be a disincentive to withdrawals from the queue since by doing so the fee is forfeited. The new connection model therefore has removed the application fee, as the costs incurred by market participants in advancing their projects themselves should provide a better safeguard against unfeasible projects.”

Request:

(a) Please provide any AESO authoritative documents which describe the queue for connection projects.

(b) In respect of the AESO’s comment that “…the application fee has not been effective at limiting connection requests to only those for viable projects, and in fact has proved to be a disincentive to withdrawals from the queue since by doing so the fee is forfeited,” please comment on the proposition that connecting market participants would be incented to limit connection requests only to projects likely to proceed if the provisions governing the queue for connection projects (and the AESO’s strict enforcement thereof) provided for the immediate forfeiture of the application fee and removal of any priority within the connection queue if any required steps are missed by the applicant.

Response:

(a) As discussed in information response AUC.AESO-015 (c)(i), the AESO is reviewing the development of an ISO rule setting out the requirements and obligations of market participants with respect to the connection queue.

The AESO is also developing an information document to update the current documentation on connection queue practices to better align with the new connection model. The proposed connection queue practices have been consulted on with stakeholders in general as well as in smaller industry working groups. The practices will go through a final consultation process in late 2010 or early 2011 as part of the AESO’s transition of authoritative documents.
The question proposes that queue management provisions be strictly enforced and projects be immediately removed if any required steps are missed. That proposition on its own would be effective at managing the connection project queue. However, the AESO has found that if a fee is paid and would be forfeited as proposed in the question, then market participants argue that circumstances beyond their control caused a step to be missed or that a required step has been minimally or partially satisfied. In effect, as stated in the quoted text in the preamble, the forfeiture of the fee has proved a disincentive to removing projects from the connection queue.

The AESO also considers that all market participants consider their projects to be viable when requesting system access service. The imposition of a reasonable fee (such as the $10,000 to $50,000 fees in the AESO’s current tariff) would not cause a market participant to reassess their project as not being viable. The AESO understands that other jurisdictions are implementing order-of-magnitude increases (to $100,000 to $250,000) to application fees, but such fees potentially represent a barrier to entry when a system access service is initially requested.

As proposed in the question, the most appropriate queue management provisions are the establishment and consistent application of clear requirements for a project to proceed through the connection queue. The AESO is developing such provisions as part of its new connection model process. The imposition of an application fee does not further enhance queue management but simply adds administration, and can be a disincentive to the withdrawal of projects from the queue.
Topic: Financial Obligations for Connection Projects

Reference: Application, Section 6.8, pages 103-106

Request:

(a) In consideration of the AESO’s proposal to eliminate the definition of “AESO Standard Facilities,” and the AESO’s Rider I proposal which should generally reduce the amounts of required customer contributions, please explain why the AESO considers that connecting market participants require additional relief in the form of the “staged” financial obligations diagrammed in Figure 6-1 of the Application (page 105).

(b) Please provide a complete description of when customer contributions paid by connecting customers are currently received by the TFO.

(c) In consideration of the contribution funds presently received by TFOs, please comment on:
   (i) How the present contribution funding arrangements (whereby contributions are received in advance of all project execution stages) impacts the overall financing requirements of TFOs.
   (ii) How the overall financing requirements of TFOs would change if contributions were to be provided in stages as described in Figure 6-1.

Response:

(a) The removal of the concept of AESO standard facilities is not expected to reduce the amounts of required construction contribution. As explained in information response AUC.AESO-018 (a), the multiplier used to determine the maximum investment level was reduced from that used under the standard facilities approach so that the amount of investment, and hence the amounts of contribution, would remain essentially the same under the proposed approach.

The proposed Rider I is available only after commercial operation of a connection project, while the financial obligations described in section 5 of the proposed tariff apply prior to and during construction of the connection project, and therefore prior to commercial operation.

The staged approach to financial obligations is proposed in the 2010 tariff primarily to align the provision of security and payment of contribution with the incurrence of costs by the TFO. This results in payments that would correspond to the incurrence of costs by the market participant if the market participant was directly responsible for the construction of the connection project. The staged approach also addresses concerns expressed by market participants when construction contributions were held for extended times during the development and construction of some projects.
(b) Under the AESO’s current tariff, a construction contribution is required to be paid in full no later than 90 days after the date on which the Commission issues permit and licence for a connection project, or prior to the start of construction of transmission facilities if such construction starts earlier than 90 days after permit and licence. This practice satisfies the requirement in section 9.2 of the current tariff, which states, “All Customer Contributions and System Contributions…must be paid by the Customer before the start of construction of transmission facilities to provide the requested service.”

(c) (i) The AESO understands that receiving construction contributions earlier would tend to increase the amount of contributions held at any point in time, which would tend to decrease TFO rate base and decrease financing requirements from other sources such as equity and debt.

(ii) Conversely, receiving construction contributions later through a staged approach would tend to decrease the amount of contributions held at any point in time, which would tend to increase TFO rate base and increase financing requirements from other sources such as equity and debt.
Topic: Investment Level Update  
Reference: Application, Appendix F  

Preamble: The Commission would like to better understand the effect of the proposed changes to investment levels.

Request:

Please present 4 to 5 scenarios, including new services and extending existing services that require transmission investment. Please compare what the level of AESO investment would be for each scenario under the existing and under the proposed investment levels. Please show calculations.

Response:

The table below summarizes application of the AESO’s contribution policy to three greenfield and two upgrade projects from those included in the 2010 POD Cost Function and Investment Level Update Workbook provided as Appendix G to the application. The detailed calculations of the 2007 and 2010 amounts for each project are provided in Attachment AUC.AESO-024.

<table>
<thead>
<tr>
<th>Project</th>
<th>Contract Capacity</th>
<th>Component</th>
<th>2007 Tariff</th>
<th>2010 Proposed</th>
</tr>
</thead>
<tbody>
<tr>
<td>#324</td>
<td>Existing 0.0MW</td>
<td>Total Project Costs</td>
<td>$6,830,000</td>
<td>$6,830,000</td>
</tr>
<tr>
<td></td>
<td>New 12.1MW</td>
<td>AESO Standard Facilities</td>
<td>$6,830,000</td>
<td>N/A</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Local Investment</td>
<td>$6,283,000</td>
<td>$7,026,295</td>
</tr>
<tr>
<td></td>
<td></td>
<td>O&amp;M</td>
<td>$0</td>
<td>$0</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Construction Contribution</td>
<td>$547,000</td>
<td>$0</td>
</tr>
<tr>
<td>#420</td>
<td>Existing 0.0 MW</td>
<td>Total Project Costs</td>
<td>$6,436,000</td>
<td>$6,436,000</td>
</tr>
<tr>
<td></td>
<td>New 6.0 MW</td>
<td>AESO Standard Facilities</td>
<td>$4,114,000</td>
<td>N/A</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Local Investment</td>
<td>$4,114,000</td>
<td>$5,179,000</td>
</tr>
<tr>
<td></td>
<td></td>
<td>O&amp;M</td>
<td>$278,640</td>
<td>$182,265</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Construction Contribution</td>
<td>$2,600,640</td>
<td>$1,439,265</td>
</tr>
<tr>
<td>#584</td>
<td>Existing 0.0 MW</td>
<td>Total Project Costs</td>
<td>$20,038,000</td>
<td>$20,0038,000</td>
</tr>
<tr>
<td></td>
<td>New 30.0 MW</td>
<td>AESO Standard Facilities</td>
<td>$18,276,000</td>
<td>N/A</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Local Investment</td>
<td>$8,797,000</td>
<td>$10,665,500</td>
</tr>
<tr>
<td></td>
<td></td>
<td>O&amp;M</td>
<td>$211,440</td>
<td>$1,359,013</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Construction Contribution</td>
<td>$11,452,440</td>
<td>$10,731,513</td>
</tr>
<tr>
<td>Project</td>
<td>Contract Capacity</td>
<td>Component</td>
<td>2007 Tariff</td>
<td>2010 Proposed</td>
</tr>
<tr>
<td>---------</td>
<td>-------------------</td>
<td>----------------------------------</td>
<td>-------------</td>
<td>---------------</td>
</tr>
<tr>
<td>#437 Upgrade</td>
<td>Existing 23.0 MW New 17.0 MW</td>
<td>Total Project Costs</td>
<td>$4,922,000</td>
<td>$4,922,000</td>
</tr>
<tr>
<td></td>
<td></td>
<td>AESO Standard Facilities</td>
<td>$4,922,000</td>
<td>N/A</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Local Investment</td>
<td>$2,006,000</td>
<td>$2,635,000</td>
</tr>
<tr>
<td></td>
<td></td>
<td>O&amp;M</td>
<td>$0</td>
<td>$331,615</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Construction Contribution</td>
<td>$2,916,000</td>
<td>$2,618,615</td>
</tr>
<tr>
<td>#592 Upgrade</td>
<td>Existing 6.0 MW New 8.0 MW</td>
<td>Total Project Costs</td>
<td>$5,483,000</td>
<td>$5,483,000</td>
</tr>
<tr>
<td></td>
<td></td>
<td>AESO Standard Facilities</td>
<td>$3,531,000</td>
<td>N/A</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Local Investment</td>
<td>$2,167,000</td>
<td>$2,703,500</td>
</tr>
<tr>
<td></td>
<td></td>
<td>O&amp;M</td>
<td>$234,240</td>
<td>$403,027</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Construction Contribution</td>
<td>$3,550,240</td>
<td>$3,182,527</td>
</tr>
</tbody>
</table>

The AESO notes that investment has increased, and construction contribution has decreased, for each project, which reflects the increase in investment level proposed in the 2010 ISO tariff based on the POD Cost Function Update as discussed in section 6.11.7 (pages 117-121) of the application.
Alberta Electric System Operator  
AESO 2010 ISO Tariff Application (1605961 ID 530)  
AESO Responses to Information Requests  
May 4, 2010

AUC.AESO-025
Page 1 of 2

Topic: 2010 POD Cost Function and Investment Level Update

Reference: Application, Appendix F

Preamble: “For its 2010 tariff application the AESO reviewed and updated the POD cost function and the resulting investment levels.” (Appendix F, page 3)

The Commission would like to better understand the 2010 POD Cost Function and Investment Level Update

Request:

When the AESO began its review of the 2010 POD cost function and the investment level update, what were the underlying issues that the AESO considered needed to be addressed in the update? Is there an overall direction that the AESO considers is desirable with respect to its investment levels?

Response:

The AESO considered that, in the time since the original POD cost function and investment level had been developed during its 2007 tariff application proceeding, connection project costs had increased substantially such that the cost function was likely no longer representative of actual project costs.

In particular, the AESO planned to update the POD cost function consistent with discussion during the AESO’s 2007 tariff proceeding. Such an expectation was included in Decision 2007-106 in that proceeding, which stated (section 8.1.2.2, page 97), “As the AESO obtains new TFO project cost information in the future, the 48 point dataset may be expanded and cost functions further analyzed. The key though is that any future changes to the investment function be based on actual project costs....”

The AESO therefore began its review of the POD cost function and investment level for its 2010 tariff application for the purpose of addressing the following matters:

(i) to increase the size of the POD cost data set by adding connection projects for which data had become available since the original data set had been created in 2006;

(ii) to review and potentially revise the price index used to escalate project costs in the data set to ensure the escalated costs would be reasonably representative of current transmission connection projects in Alberta;

(iii) to determine an updated POD cost function from the updated data set using the same best-fit approach and the same breakpoints as used in the development of the original POD cost function; and
(iv) to determine an updated investment level reflective of the updated POD cost function, based on actual connection project costs.

The AESO considers that, overall, investment levels should be stable and predictable in form and structure, and should generally remain aligned with the anticipated actual cost of connection projects.

Stability and predictability are provided by basing investment levels on the POD cost function. Alignment with the anticipated actual cost of connection projects is provided by updating project costs as in the current application or by applying an escalation factor as proposed in section 8.1 of the application.
Topic: Investment Level Update

Reference: Application, Appendix F, page 14

Preamble: “Defining standard facilities was an approach that limited investment when maximum investment levels could otherwise have significantly exceeded the actual project cost. However, under the current tariff there is better alignment between costs and investment levels.”

Request:

Please explain how there is better alignment between costs and investment levels in the current tariff and what assurance there is under the proposed methodology that this alignment will continue.

Response:

The AESO proposed the current standard facilities definition in its 2006 tariff application. In that application it also proposed a uniform $/MW/year maximum investment level that did not recognize economies of scale for connection projects. The investment level approved as a result of that tariff application included both a $/year fixed component and a single $/MW/year capacity component, and provided limited recognition of economies of scale for connection projects.

The contribution study and related analysis in the AESO’s 2007 tariff proceeding showed that connection project costs do exhibit economies of scale and are best represented by a power curve function. Since costs are best represented by a power curve function, a single straight-line maximum investment level (either as proposed or as approved in the AESO’s 2006 tariff proceeding) would not align particularly well with project costs. The misalignment would mean that, in at least some cases, the maximum investment would be significantly greater than the anticipated cost of a connection project. The standard facilities definition attempted to address this misalignment by limiting the facilities that would otherwise be eligible for this higher-than-cost investment.

In the current tariff, the maximum investment level is based on the power curve function that best represents connection project costs and accordingly exhibits appropriate economies of scale. It is therefore less likely that the maximum investment would be significantly greater than the anticipated cost of a connection project, and there is less need to specifically limit the facilities that would be eligible for investment.

The proposed methodology continues to base the maximum investment level on the power curve function that best represents connection project costs. The AESO considers that maintaining the cost function basis for the maximum investment level will continue the alignment between costs and investment levels.
Topic: AltaLink Led Consultations

Reference: Application, Section 3, page 20
Application Section 6.11, pages 107-109

Preamble: Quote: “Other consultation processes also provided information for the AESO’s tariff development. In particular, AltaLink lead an industry consultation process during 2008 that identified concerns with the AESO’s construction contribution policy and made recommendations, without prejudice, for consideration in the design of the next AESO contribution policy.” Page 20, Paragraph 83

In the quoted passage above, the AESO references consultations led by AltaLink which considered the AESO’s contribution policy. In section 6.11, the AESO takes notes of a number of principles recommendations that were made as part of the AltaLink consultations and provides additional comments on three of them.

Request:

Please file a copy of the final report document and any other notable documents that may have been prepared as part of the AltaLink led consultations described above.

Response:

Please see Attachment AUC.AESO-027, which provides the “Recommendations for Consideration regarding the Customer Contribution Policy” from the AltaLink stakeholder consultation process. This is the only document provided formally to the AESO as a result of the AltaLink process.