Reference: Section 4, page 46; Export, Import and Merchant Interconnection Tariff Development Stakeholder Comments and AESO Responses August 22, 2005

Request:

(a) How long would it take the AESO to upgrade its transmission scheduling system to an OASIS? Does the 6-month estimate in the referenced comments remain appropriate?

(b) Please state the specific conditions under which an OASIS will be implemented.

(c) Please identify any seams issues with other jurisdictions that the AESO has identified with respect to proposed rate XTS and an OASIS, as a result of its consultations with BCTC, SaskPower and other stakeholders. How does AESO intend to address these seams issues?

(d) What alternatives to an OASIS are being considered by the AESO? Please describe the key similarities and differences in the capabilities of the various alternatives.

(e) How would the proposed tariffs be accommodated between the time that they are approved and the time that an OASIS is implemented?

(f) What business rules/operating procedures would have to be updated to accommodate the proposed tariffs?

Response:

(a) The 6 month estimate remains appropriate.

(b) An OASIS will be implemented upon the approval of multiple export rates.

(c) Please see the response to TCE.AESO-052 (c).

(d) The AESO considered 2 alternatives to an OASIS system: a manual implementation and a custom built system. A manual implementation would differ from the other two in that it would entail paper records and manual data entry into existing energy management (EMS) and settlement systems. A custom built system would be similar to an OASIS system, but would differ in that it would be a custom application developed from a detailed functional specification.

(e) Please see the response to TCE.AESO-049 (c).

(f) The AESO expects several new business practices or operating policies and procedures (OPPs) will be required and that existing OPPs respecting interconnection operation will require some revision in order to implement the export rates.
Reference: Section 4.8.1, page 46, paragraph (e)

Request:

Please provide any information available to the AESO regarding when the current Transmission Regulation may be updated and losses can be applied to the XTS tariff.

Response:

The AESO does not know when the current Transmission Regulation may be updated.
Reference:  Proposed increase in opportunity service export tariff charges

Request:

(a) Please provide any and all analyses prepared by the AESO regarding whether the proposed increase in the export rates will block otherwise economic trades.

(b) Has the AESO considered discounting of export tariffs, when appropriate, to facilitate trade? Please explain your response.

Response:

(a) The AESO did not perform any analysis in this regard.

(b) No. The proposed Export Opportunity Service (XOS) rates are generally cost based, and therefore cannot be further discounted. They are designed to recover incremental costs with varying contributions to fixed costs depending on curtailment provisions. Please refer to pages 44-49 of section 4 of the Application for additional information.
Reference: Appendix C, page 14, planning for export and import loads

Request:

(a) Please state the specific assumptions that the AESO uses for planning purposes regarding both export and import loads.

(b) Please state the AESO’s understanding of its legal obligation to plan for export and import opportunity service loads.

Response:

(a) Opportunity export and import loads are generally not included in forecasts used to assess the need for intra-Alberta system reinforcement.

(b) The AESO is not required to plan for import and export opportunity service loads. It is generally understood that the term “opportunity” means a transaction is able to proceed given capacity is available that is otherwise used and paid for by firm rate paying customers, for whom the system is planned. The AESO notes that the requirements of Paragraph 8(1)(g) of the Transmission Regulation to restore inter-tie capacity to original design levels will create additional capacity, that may be available for opportunity sales, but the purpose of that paragraph is not for opportunity service specifically.
Alberta Electric System Operator
AESO 2007 General Tariff Application (1485517)

AEO Responses to Information Requests
January 24, 2007

PWX.AESO-005 (a-c)  Page 1 of 2

Preamble: The AESO indicates that cost classification is typically not based on contingency conditions, although planning decisions do accommodate such conditions. Appendix C indicates that the system is planned with computer simulations.

Reference: Section 4, page 9 line 40 to page 11 line 3; Appendix C page 13, pages 33-34

Request:

(a) Please discuss whether the AESO will expand capacity when load flow models simulated under contingency conditions indicate that overloading problems will occur on specific line segments but actual peak loads on those segments do not violate system constraints.

(b) Please comment on whether actual conditions or contingency conditions are more consistent with the principle of cost causation, as opposed to the standard of the practices of other utilities.

(c) Please explain how loads are specified for the AESO’s computer simulations in its planning studies. As part of your response, please address the following:

   (i) Are these loads generally based on actual peak demands observed at specific PODs?

   (ii) How do these demands recognize weather variations and load growth?

   (iii) How are firm and opportunity export and import loads modeled in these simulations?

Response:

(a) The AESO understands the question to be asking if the AESO would seek to alleviate forecast overloads resulting from forecast post-contingency flows even if actual flows (whether under “normal” conditions with all elements in service or under post-contingency conditions) do not cause overloads. Yes, in general, overloads forecast to occur under post-contingency conditions would require system reinforcement, as would overloads from actual flows.

(b) The transmission system is planned, built, and operated to provide service to customers under a wide range of conditions, including under “normal” conditions with all elements in service as well as under post-contingency conditions. Actual operation of the transmission system includes both normal and post-contingency conditions, and represents the actual relative frequency of such conditions. Data representing actual operation of the system, as used for the AESO’s proposed allocation of system costs to users, accordingly reflects both normal and post-contingency conditions and therefore provide a sound basis for cost causation analysis.
Although the AESO has not surveyed the standard practices of other utilities, the AESO understands that basing cost causation analysis on recent usage of the system is a common approach.

(c) (i-ii) Individual POD load forecasts are based on trending from historical actual data and incorporating load forecasts based on general information, local area information, and, in some cases, individual customer data including customer forecasts and customer contract information. Sensitivities are generally applied to load and generation scenarios to test the validity of the assessment of the loading concern and the proposed remedy.

(iii) The AESO has not had firm import and export tariffs in place, and hence has not modeled such loads. Opportunity imports and exports have been modeled in some analyses to understand potential impacts and capabilities on the transmission system.
Preamble: The AESO indicates that it had not specifically canvassed individual customer needs but anticipated identifying such needs through consultation.


Request:

Please detail the AESO’s consultations in this respect, and provide the results of those efforts.

Response:

Export, import, and merchant tariff requirements since August 22, 2005, were developed through:

- a formal meeting with stakeholders on September 7, 2005;
- informal discussions and meetings with individual stakeholders;
- informal discussions in the context of the ATC Working Group; and

Written documents and presentations related to this consultation are posted on the AESO’s website and were distributed to stakeholders during the consultation process. The results of these efforts are incorporated into the export, import, and merchant tariff discussions in sections 4.8 and 4.9 of the AESO’s 2007 GTA.
Preamble: The AESO recommends the use of an average-and-excess ("A&E") allocation approach for bulk systems costs, and proposes to recover the excess component on a non-coincident peak demand charge basis.

Reference: Section 4, page 17

Request:

(a) Please reconcile the use of a peak demand billing determinant for recovery of an excess demand-related cost.

(b) Please confirm that the AESO's proposal is consistent with a "peak-and-average" allocation methodology rather than an A&E approach. If you cannot confirm, please explain your response.

(c) Please provide a numerical example depicting the allocation of costs to several representative customers using the A&E method compared to the rates that such a customer will pay under the proposed NCP demand and energy charges. Please include the specific weighting factor (system coincident peak), as well as average demand, non-coincident peak demand and excess demands for both the customer and total used in the example.

Response:

(a) Please refer to the response to Information Request EnCana.AESO-012 (b).

(b) Not confirmed. The AESO understands the principle difference between the two methodologies is as described in The Process of Ratemaking by Leonard Saul Goodman (Public Utilities Reports, Inc., Vienna, Virginia, 1998, p 1070):

The major difference between the average and excess method, on the one hand, and the average and peak method, on the other, is that the average and excess method uses class maximum peaks whereas the average and peak method used class coincident peaks.

The AESO's proposal is based on non-coincident peaks and is an average and excess demand approach. Please refer to the responses to Information Requests BR.AESO-002 (a) and EnCana.AESO-012 (b) for additional information.

(c) The average and excess demand approach is the approach used in the AESO's rate design, so there would be no difference in the allocation of costs.
Reference: Export service tariff cost basis

Request:

(a) Please explain fully why local system costs are included in the cost basis for XTS and XOS rates.

(b) Please detail the facilities that are included in the AESO’s definition of the local system and indicate whether each type of facility is used by export service customers.

(c) Please detail the impact on XTS and XOS tariff charges of excluding local system costs from the cost basis for these rates.

(d) Please provide the cost causation basis for applying the same variable charge to opportunity service export (Rate XOS) energy, which may be interrupted or constrained, as to firm service domestic energy for bulk service facilities.

(e) Please provide the cost causation basis for applying the full cost of the bulk system to the tariff charges for Rate XTS, when Rate XTS demand may be constrained by ATC and domestic demand is not.

Response:

(a) The proposed export rates are designed on a “network service” basis similar to domestic rates, where electricity flows over the transmission system from a conceptual power pool to a delivery point at the Alberta border. Specific transmission facilities are not generally associated with a service’s access to the power pool, whether for export or domestic use, and access to the pool is not differentiated by cost sub-function or by voltage level. Export services therefore include allocations of both bulk and local system costs.

(b) As explained in part (a) above, access to the power pool is not differentiated by cost sub-function or by voltage level.

However, as discussed in the original Transmission Cost Causation Study (provided as Appendix B to the AESO’s 2006 GTA filed on January 31, 2005), one view of differentiating bulk and local system facilities is based on voltage level: 240 kV and 500 kV facilities are considered bulk system, while 69/72 kV and 138/144 kV facilities are considered local system. With respect to facilities over which export flows occur, the AESO notes that 138 kV lines from Pocaterra and Coleman in Alberta connect to Natal in BC, and a 138 kV line also connects Alberta to the McNeill Converter Station used for the Alberta-Saskatchewan inter-tie.

(c) Excluding local system costs would reduce the interconnection charge components of the XTS and XOS rates.
For Rate XTS, excluding the local system costs would decrease the interconnection charge to about $3.53/MWh from the proposed $4.98/MWh.

For Rate XOS 1 Hour, excluding the local system costs would decrease the energy transfer charge to about $4.01/MWh from the proposed $4.71/MWh, as the proposed charge includes only the $/MWh component of local system costs.

For Rate XOS 1 Month, a similar change would decrease the energy transfer charge to about $4.91/MWh from the proposed $5.99/MWh. The reduction is larger than for Rate XOS 1 Hour as the XOS 1 Month charge includes both the $/MWh component of local system costs and 50% of the $/MW component (converted to a $/MWh basis).

(d) Variable charges are incurred when energy actually flows, regardless of the “firmness” of service. The difference in “firmness” attributable to the possibility of interruption or constraint is recognized in the reduction or elimination of the $/MW component of system costs in the export opportunity rates.

(e) An XTS customer is only charged for service in hours in which sufficient capacity exists to accommodate the energy transfer. If ATC is not available the XTS customer is not charged for contracted export service and minimum charge provisions do not apply. This reasonably addresses any ATC limitations which may exist, and is conceptually comparable to a DTS contract minimum which appropriately applies in every hour when capacity is generally available in every hour.
Reference: Table 4.8.3 and XTS tariff, operating reserve charge

Request:

Please reconcile the 3.33 percent of pool price in the table with the 2.29 percent of pool price in the tariff. Is it the AESO’s intent to use 3.33 percent of pool price in this tariff or $2.29 per MWh? Please explain your response.

Response:

Rate XTS in section 7 of the Application should have included an operating reserve charge based on 3.33% × Pool Price, equivalent to the operating reserve charge in Rate DTS.

The operating reserve amount was converted to $2.29/MWh for the derivation of opportunity service rates in Schedule 5.8 in section 5 of the Application. That value was inadvertently substituted in the operating reserve charge on the XTS rate schedule.
Request:

Please provide a database in MS Excel electronic format showing hourly import and export flows for 2005 and year-to-date 2006 between Alberta and British Columbia, and between Alberta and Saskatchewan. Please include hourly import and export ATCs in the dataset.

Response:

Please refer to Attachment PWX.AESO-010.
Request:

Please provide the details of actual revenues earned by the AESO on export and import transactions for 2005 and year-to-date 2006, on an hourly basis to the extent it is available, split between losses charges, variable charges and transaction charges.

Response:

The details of actual revenues on export and import transactions for 2005 and 2006 are not both stored on an hourly basis. The monthly losses charges, variable charges, and transaction charges for both exports and imports are provided in Attachment PWX.AESO-011.
Reference: Section 4.8.1

Request:

Please explain how the lower quality of service for XTS associated with earlier curtailment (paragraphs (b) and (f)) is recognized in the XTS tariff.

Response:

Please refer to the response to Information Request TCE.AESO-053 (a-c).
Reference: Section 4.8.2, XOS service

Request:

(a) Please explain why the proposed operating reserve charge for XOS is a fixed dollar per MWh rather than a percent of pool price as suggested in the proposed XTS tariff.

(b) Please explain how the lower quality of service for XOS associated with earlier curtailment (paragraph (h)) is recognized in the XOS tariff.

Response:

(a) The AESO generally understands that customers prefer certainty of price for opportunity service transactions. The operating reserve charge was therefore converted to a fixed dollar per MWh amount, consistent with currently approved DOS and EOS opportunity rates.

(b) The earlier curtailment of XOS is recognized through lower interconnection charges and no voltage control or other system support services charges, compared to XTS. XOS also has a lower minimum charge percentage and shorter minimum terms, and is not subject to deferral account treatment.
Reference: Schedule 5.2, Export and Merchant Service Revenue and Import revenues

Request:

Please provide the supporting workpapers and analysis (in MS Excel electronic format) regarding the forecast of export and import revenues for 2007.

Response:

Please refer to attached Schedule PWX.AESO-014.
Reference: Appendix C, Table 1, exports contributing to cause of constraining for the 944L/951L and the 6-240 kV circuits between Calgary and Edmonton, and page 14

Request:

(a) Please indicate whether the exports identified as the constraining factor for these facilities are opportunity service flows.

(b) Will the AESO interrupt opportunity service exports if they give rise to unacceptable stresses on the referenced components of the transmission system? If your answer is affirmative, please explain how the exports can be the cause of the constraint.

(c) Does the AESO reduce the export ATC during periods in which export flows contribute to system constraints? If your answer is affirmative, please explain your response and provide any analyses prepared by or on behalf of the AESO regarding the impact of these constraints on export flows.

Response:

(a) Under the current tariff, all exports are classified as opportunity service. Exports contribute to loading of the transmission paths on 944L/951L and the six 240 kV circuits between Calgary and Edmonton.

(b) Confirmed. The AESO will interrupt opportunity service exports where they contribute to unacceptable stresses on the transmission system.

Exports to Saskatchewan will increase loading on the 944L/951L and the six 240 kV circuits between Calgary and Edmonton.

Exports to British Columbia will increase loading on the six 240 kV circuits between Calgary and Edmonton.

(c) Confirmed. The AESO will reduce the export ATC during periods in which export flows contribute to system constraints.

As described in AESO OPP-304:

The Alberta-BC export ATC depends on the SOK-240 limits (refer to OPP 521), and is calculated as: [SOK-240 Available Transfer Capability (ATC) minus Forecast SOK load plus Forecast SOK generation] multiplied by Export Conversion Factor

where:
- SOK-240 ATC is as defined in OPP 521, and
• Forecast SOK load is the sum of the forecast loads downstream of the SOK cut plane as defined in OPP 521, and
• Forecast SOK generation is the estimated in-merit generation downstream of the SOK cut plane as defined in OPP 521, and
• Export Conversion Factor is a factor to convert SOK capability to export capability and to account for the associated increase in losses; it is deemed to be 0.95 as confirmed by studies.
Reference: Appendix C, page 37 and Schedule 5.3

Request:

(a) Please reconcile the 51.4/48.6 NCP/Energy classification of bulk system costs at Schedule 5.3 with the 81.5/18.5 classification split cited in Appendix C.

(b) Please explain how the AESO’s proposed XTS and XOS tariff charges would be modified if the Board approves the 81.5/18.5 NCP/energy classification methodology.

Response:

(a) The classification of bulk system costs was modified for rate design purposes as fully discussed in section 4.5.1 of the Application, on pages 15-17 of Section 4.

(b) The demand- and usage-related classification of bulk system costs affects only the interconnection charge components of the XTS and XOS rates.

For Rate XTS, varying the demand- and usage-related proportions would have negligible impact, as the Rate XTS interconnection charge is calculated as if all bulk system costs were recovered on a usage ($/MWh) basis.

For Rate XOS 1 Hour, increasing the demand-related proportion to 81.5% and decreasing the usage-related proportion to 18.5% would decrease the energy transfer charge to about $3.66/MWh from the proposed $4.71/MWh, as the charge includes only the $/MWh component of bulk system costs.

For Rate XOS 1 Month, similar changes would decrease the energy transfer charge to about $5.48/MWh from the proposed $5.99/MWh. The reduction is smaller than for Rate XOS 1 Hour as the XOS 1 Month charge includes both the $/MWh component of bulk system costs and 50% of the $/MW component (converted to a $/MWh basis).
Reference: Appendix C, page 38, Calgary-Edmonton transmission planning

Request:

Please detail the load conditions that are assumed when evaluating the stresses and planning the expansion of the Calgary-Edmonton transmission system. Please be specific regarding the level of non-recallable and recallable exports assumed.

Response:

Multiple load conditions and years are considered when performing system planning for the Edmonton-Calgary bulk transmission system. Years studied are +1, +5, +10, and +15 years into the future. The conditions include, but are not necessarily limited to:

- system winter peak, no wind production, no imports, single largest south generator out-of-service
- system winter peak, no wind production, imports, single largest south generator out-of-service
- system winter peak, no wind production, imports
- system summer peak, no wind production, no imports, single largest south generator out-of-service
- system summer peak, no wind production, imports, single largest south generator out-of-service
- system summer peak, no wind production, imports
- south of SOK regional summer peak, no wind production, no imports, single largest south generator out-of-service
- south of SOK regional summer peak, no wind production, imports, single largest south generator out-of-service
- south of SOK regional summer peak, no wind production, imports
- summer shoulder period (south gas generation and imports out-of-merit), no wind production
- summer shoulder period (south gas generation and imports out-of-merit), no wind production, single largest south generator out-of-service
- summer night (south gas generation and imports out-of-merit), no wind production, maximum exports, single largest south generator out-of-service
- summer night (south gas generation and imports out-of-merit), no wind production, maximum exports
- summer night (south gas generation and imports out-of-merit), maximum wind production, maximum exports
- spring night (light load), no wind production, maximum exports, single largest south generator out-of-service
- spring night (light load), no wind production, maximum exports
- spring night (light load), maximum wind production, maximum exports
No distinction is made regarding the level of non-recallable and recallable exports assumed. Exports were forecast and modeled primarily to assess the amount of congestion appearing on the Edmonton-Calgary system, and were not considered in assessing transmission line loss savings associated with transmission system reinforcement. Export conditions are evaluated with the export paths loaded to their maximum WECC path ratings.
Reference: Proposed rate schedule XTS, Section 4, page 46

Request:

How will ATC be allocated among XTS customers in the event it falls below contracted capacity? Please explain your response.

Response:

Please refer to the response to Information Request TCE.AESO-057 (b).
Preamble: AESO states, “As generation cannot be identified as serving opportunity loads, XOS customers contribute to the AESO’s requirement to carry operating reserves, and should therefore pay those costs like other export customers”.

Reference: Section 4, page 48

Request:

(a) Please provide references to WECC and NWPP requirements indicating that opportunity service or interruptible service loads must be included in operating reserve requirements.

(b) Please provide references to the AESO’s operating policies indicating that the AESO can and must contract for operating reserve in support of opportunity service exports.

Response:

(a) The WECC Minimum Operating Reserve Criteria, Section 1 A requires operating reserve to be carried for load responsibility. WECC defines load responsibility as “A control area’s firm load demand plus those firm sales minus those firm purchases for which reserve capacity is provided by the supplier.” For the purpose of calculating operating reserves requirement, the Alberta control area has historically included exports as part of load responsibility.

(b) Please refer to section 3.1 of both OPP 402 and OPP 406. These OPPs indicate that for operating reserve calculations, the AESO considers exports to be firm and that firm export transactions are included in firm load responsibility calculations. Firm load responsibility is the basis for determining operating reserve requirement.
Reference: Sections 4.8.1 and 4.8.2

Request:

(a) Please prepare a table comparing the primary features of the proposed XTS rate to a standard firm service within an OATT-compliant tariff.

(b) Please prepare a table comparing the primary features of the proposed XOS rate to a standard non-firm service within an OATT-compliant tariff.

Response:

(a) The following table compares the primary features of the proposed Export Transmission Service (XTS) to a standard OATT firm service.

<table>
<thead>
<tr>
<th>Service Model</th>
<th>Proposed XTS</th>
<th>OATT Standard Firm Service</th>
</tr>
</thead>
<tbody>
<tr>
<td>Service Model</td>
<td>Injection-Withdrawal.</td>
<td>Point-to-point.</td>
</tr>
<tr>
<td>Cost Recovery</td>
<td>Recover wires costs.</td>
<td>Recover wires costs.</td>
</tr>
<tr>
<td>Rate Structure</td>
<td>$/MWh, when ATC is available.</td>
<td>$/MW.</td>
</tr>
<tr>
<td>Ancillary Services Required</td>
<td>Operating reserve, voltage control, and other system support as outlined in XTS rate schedule.</td>
<td>Operating reserve requirements vary by control area. Reactive supply and voltage control; scheduling, system control, and dispatch; regulation and frequency response; and energy imbalance.</td>
</tr>
<tr>
<td>Terms of Payment</td>
<td>Pay for usage. Minimum charge of 90% of Schedule. No charge when ATC is not available.</td>
<td>Take or pay.</td>
</tr>
<tr>
<td>Term</td>
<td>1 year minimum.</td>
<td>1 hour to unlimited.</td>
</tr>
<tr>
<td>Curtailment</td>
<td>Just before DTS (Step 29 of OPP 801).</td>
<td>Firm service, regardless of point of delivery, and network service is curtailed at the same time on a pro rata basis.</td>
</tr>
<tr>
<td>Re-Assignment/Re-sale</td>
<td>Yes.</td>
<td>Yes.</td>
</tr>
<tr>
<td>Change POR/POD</td>
<td>No.</td>
<td>Yes, subject to ATC on new path.</td>
</tr>
<tr>
<td>Losses</td>
<td>Location -specific. Currently 0.00%.</td>
<td>Can be either system average or path specific.</td>
</tr>
</tbody>
</table>
The following table compares the primary features of the proposed Export Opportunity Services (XOS) to a standard OATT non-firm service.

<table>
<thead>
<tr>
<th>Service Model</th>
<th>Proposed XOS</th>
<th>OATT Standard Non-Firm Service</th>
</tr>
</thead>
<tbody>
<tr>
<td>Service Model</td>
<td>Injection-withdrawal.</td>
<td>Point-to-point.</td>
</tr>
<tr>
<td>Cost Recovery</td>
<td>Recover system variable costs.</td>
<td>Recover wires costs.</td>
</tr>
<tr>
<td></td>
<td>XOS 1 Month also recovers a portion of the fixed system costs.</td>
<td></td>
</tr>
<tr>
<td>Rate Structure</td>
<td>$/MWh, when ATC is available.</td>
<td>$/MW. May be discounted by the system operator.</td>
</tr>
<tr>
<td>Ancillary Services Required</td>
<td>Yes, as outlined in XOS rate schedule. There are no POD, voltage control, or other system support charges.</td>
<td>Same as Firm Service.</td>
</tr>
<tr>
<td>Terms of Payment</td>
<td>Pay for usage. Minimum charge of 75% of Schedule. No charge when ATC is not available.</td>
<td>Pay for usage.</td>
</tr>
<tr>
<td>Term</td>
<td>1 hour to 1 year.</td>
<td>1 hour up to 11 months.</td>
</tr>
<tr>
<td>Curtailment</td>
<td>Just before DOS (Step 6 of OPP 801).</td>
<td>Before network or firm service.</td>
</tr>
<tr>
<td>Re-Assignment/Re-sale</td>
<td>Yes.</td>
<td>Yes.</td>
</tr>
<tr>
<td>Losses</td>
<td>Location-specific. Currently 2.10% to 4.13%.</td>
<td>Can be either system average or path specific.</td>
</tr>
</tbody>
</table>

Request:

Please describe the status of the ATC Export Capacity Consultation Process and provide a reference to the supporting documentation for that process and any findings that arose from that process.

Response:

The consultation process is ongoing through the activities of the export work group.

The AESO has been working collaboratively with a variety of stakeholders (including Powerex) over the last 2 years. The AESO and other stakeholders in this process have implemented, or are planning to implement, a number of operational and capital improvements to expand Alberta to BC export capacity:

- Inclusion of Calgary area marginal (non baseload) generation in Available Transfer Capability (ATC) calculations (2005);
- Alleviating Calgary area voltage stability constraints by installing capacitor banks at Janet, Sarcee and East Calgary substations (February, 2006);
- Implementation of South of Keg (SOK) cut-plane software to enhance the determination of export ATC (May, 2006);
- AltaLink 900L thermal upgrade (July, 2006);
- AltaLink agreement to allow AESO OPP changes and operator actions to address post-contingency thermal overloads on the underlying 138 kV system (July, 2006);
- Inclusion of imports (southern AB generation in energy merit order) and wind (persistence factors) in ATC calculations (pending in October, 2006);
- Planning the implementation of Generator Remedial Action Scheme (GRAS), Generator Runback, Transmission Remedial Action Scheme (TRAS) and Capacitor Bank Remedial Action Scheme service (2007);
- Reviewing Transmission Facility Owner (TFO) line rating standards and evaluating options for temperature sensitive dynamic thermal line ratings (2007);
- BCTC relaxation of 700 MW Alberta to BC export limit in off-peak hours;
- BCTC studying requirements for extending off-peak export limits to 1000 MW (i.e. further monitoring of southeast BC generation levels, Natal post-contingency thermal overloads, Alberta GRAS, etc.);

The AESO is also working with stakeholders on a number of non-technical issues to support export capability including:

- Tariff development;
- Market rule development; and,
- Various other issues including Long Term Adequacy, the impact of wind generation, merchant transmission facilities and intra-hour dispatchability.
With expenditures on the order of $500,000 on capital upgrades, operating policies, software and consultants, the export work group initiatives noted above have resulted in an increase of approximately 400 MW to both the South of Keg (SOK) flow limits and Alberta to BC export capacity.

Additional information can be found on the AESO website under Grid Operations/System Studies/Export Capability (http://www.aeso.ca/gridoperations/8904.html).