May 31, 2009

Export and Import Rates XTS and ITS Working Group Members
AESO Stakeholders

Dear Working Group Member:

Re: Meeting Agenda for Export and Import Rates XTS and ITS Working Group

The first meeting of the Export and Import Rates XTS and ITS Working Group for the AESO’s 2010 tariff application is scheduled as follows:

- **Time:** 11:00 AM to 1:00 PM
- **Date:** Tuesday, June 2, 2009
- **Location:** Meeting Room 2506, AESO Office, 330 – 5th Avenue SW, Calgary
- **Refreshments:** Light working lunch and beverages

This working group includes the following members:

- ATCO Power: Kim Johnston
- IPCAA: Vittoria Bellissimo
- MATL: Bob Williams or Paul Kos
- NaturEner: Juliane Kniebel-Huebner
- Powerex: Lisa Cherkas
- TransCanada: Chris Best
- UCA: Rick Cowburn
- AESO: John Martin, Raj Sharma, and Gordon Nadeau

If you intend to participate in the meeting by conference call, are unable to attend the meeting, or will be represented by an alternate, please let me know as soon as possible. Powerex has already advised that they will participate in this first meeting by conference call.

The agenda for the meeting is proposed to include the following items:

1. **Introductions**
   - Please indicate which stakeholders you represent
   
2. **Review agenda**
   
3. **Review draft working groups terms of reference**
   - See enclosed document originally posted on April 22, 2009
   - The AESO proposes to revise section 3 of the draft terms of reference by updating the first bullet point and adding an additional bullet point, as follows:
— 2 —

- Each Working Group will generally have a maximum of six to eight members (including AESO employees and consultants). No more than six stakeholder members will generally be on any one Working Group.
- A company or association may have only one individual participating in any specific working group meeting, although that individual may be an alternate to the usual representative of that company or association.

- Identify any concerns with or additional revisions to the terms of reference
- Terms of reference will be finalized after initial meetings for all working groups are complete

4 **Background for Export and Import Rates XTS and ITS**

11:20 AM

- Please review the enclosed information before the meeting, if possible:
  (a) Compilation of legislation and policy relating to exports and imports, including excerpts from the Electric Utilities Act, Transmission Regulation, Transmission Development Policy, and Electricity Policy Framework
  (b) Discussion of export and import rates in section 7 (pages 76-91) of Decision 2007-106 on the AESO’s 2007 General Tariff Application, released on December 21, 2007
  (c) Discussion of export and import rates in section 5.8 (pages 33-37), and of merchant rates in section 7.4 (pages 78-80), of Decision 2005-096 on the AESO’s 2005-2006 General Tariff Application, released on August 28, 2005

- Is there other background that participants consider particularly relevant?

5 **Scope for Export and Import Rates XTS and ITS Working Group**

11:30 AM

- Definition of “firmness” for export and import transmission service
- Tariff implications of priority distinctions for export and import services
- Rate design principles for higher priority export and import services
- Similarities and differences between domestic and intertie transmission service and rates
- Allocation of transmission costs to export and import rates
- Working group will not review or discuss the following items which are being addressed through the Market Advisory Committee (MAC) Interties Subcommittee:
  – restoration of intertie capacity and construction of new interties;
  – ATC (Available Transfer Capability) levels;
  – business practices for interties, including curtailment, scheduling, allocation of ATC among interties, and other procedures; and
  – market and pool price interaction and impacts of exports and imports.

6 **Firmness and priority distinctions for export and import rates**

11:45 AM

- AESO’s current tariff includes two opportunity export rates (one of which will not be available until an OASIS is implemented) and a single opportunity import rate
- What would firm rates imply, and do conditions exist such that firm rates can be offered?
- What do different priorities of opportunity rates imply?

7 **Rate design principles for higher priority export and import services**

12:15 PM

- Government policy suggests firm export service should be priced at the same level as firm domestic load service, and firm import service at the same level as firm domestic generation service
• Government policy also suggests opportunity services should be priced at a discount from firm services
• All AESO rates, including those charged for export and import services, must be just and reasonable
• What does this mean for export and import services?

8 Follow-up required for next meeting 12:45 PM
• Summarize what tasks need to be completed before next meeting and who will complete them

9 Dates and times for next meeting(s) 12:55 PM

10 Adjourn 1:00 PM

This agenda and all other printed information related to the Export and Import Rates XTS and ITS Working Group is available on the AESO’s website at www.aeso.ca by following the path Tariff ► Current Consultations ► 2010 Tariff. The AESO appreciates stakeholders’ participation in this consultation.

If you have any comments or questions on this consultation process or the AESO’s tariff application, please contact me at 403-539-2465 or john.martin@aeso.ca, or Raj Sharma at 403-539-2632 or raj.sharma@aeso.ca.

Sincerely,
[original signed by]

John Martin
Director, Tariff Applications

enclosures

c: Raj Sharma, Senior Tariff Analyst, AESO
1 Purpose

The AESO 2010 Tariff Consultation Working Groups will be forums for stakeholders to provide perspective, advice, and expertise to the AESO on specific topics for the AESO’s 2010 tariff application. The Working Groups are intended to augment the internal capabilities of the AESO and support effective consultation by engaging stakeholders in the development of the tariff application.

2 Topics

Working Groups are proposed to examine the following topics for the AESO’s 2010 tariff application. Some issues are suggested for exploration within each topic, although each Working Group is expected to determine what issues should be examined for each topic.

(a) **POD Cost Function and Investment Level Update**
   - Substations included in POD cost data set
   - Inflation index to escalate POD cost data to 2010
   - Multiplier to determine investment level

(b) **TFO O&M Cost Causation Study**
   - Respond to AUC directions on analysis of TFO O&M costs
   - Determine if TFO O&M costs are energy-related
   - Determine if TFO O&M costs should be functionalized similarly to capital costs

(c) **DTS Operating Reserve Charge Design**
   - Methodology to analyze and assess design of operating reserve charge
   - Criteria for selection of appropriate design for operating reserve charge

(d) **Fort Nelson Rate FTS**
   - Rate design principles for Fort Nelson and similar services
   - Cost allocation approaches between BC and Alberta loads in the Rainbow Area
   - Contractual considerations for Fort Nelson and similar services

(e) **Export and Import Rates XTS and ITS**
   - Rate design principles for higher-priority export and import services
   - Similarities and differences between domestic and intertie services
   - Potential allocation of “deep system” costs to services over merchant interties

(f) **Deferral Account Riders B and C**
   - Rate design principles for deferral account riders
   - Practicality of improving allocation accuracy of deferral account riders
   - Possible integration of Riders B and C
Tariff Changes Related to Transition of Authoritative Documents (TOAD)
- Provisions that could be moved from tariff to other authoritative documents (such as technical standards or ISO Rules)
- Common provisions that could be standardized and consolidated
- Dispersed information that could be consolidated

Amortized Customer Contribution Option and Other Contribution Provisions
- Potential changes to AESO standard facilities definition
- Potential provisions for amortized customer contribution option
- Assessment of credit-worthiness and mitigation of risk of default

Tariff Provisions Related to Customer-Owned Substations
- Principles for tariff provisions at customer-owned substations
- Assessment of Primary Service Credit and associated investment factor
- Application of substation fraction at customer-owned substations

3 Working Group Members

The Working Groups will consist of AESO stakeholders and AESO employees with interest, expertise, or both in the specific topic being examined in each Working Group.
- Each Working Group will have a maximum of four to six members (including AESO employees). No more than four stakeholder members will be on any one Working Group.
- Stakeholder involvement in a Working Group is voluntary. Membership will generally be on a first come, first served basis.
- Stakeholders may coordinate involvement in different Working Groups among themselves to avoid duplication and overlap of interest.
- The AESO may suggest changes to the composition of individual Working Groups to ensure diversity and balanced representation of views.

4 Duration

Each Working Group will be active from May 1, 2009 to no later than mid-July 2009.
- A Working Group may conclude activities earlier if no further review of the topic would be helpful to the AESO’s 2010 tariff application.
- A Working Group may also continue activities for a longer period if an extension is required to effectively satisfy its purpose.

5 Scope and Duties

Working Groups will review and discuss options and alternatives for proposals being considered for inclusion in the AESO’s 2010 tariff application. Working Groups are not decision-making bodies. Consultation within Working Groups will not replace general stakeholder consultation. The AESO will consider consultation within the Working Groups in the context of its broader stakeholder consultation.
(a) Working Groups will determine their own meeting dates and times. Meetings are expected to occur about every two weeks, for one to two hours. Meeting agendas will be prepared and communicated in advance as much as practical. Members may participate in meetings via conference call. A Working Group will generally be coordinated and chaired by an AESO employee. Meetings may be held at the office of the AESO or of other Working Group participants.

(b) Working Group members are expected to dedicate appropriate time to actively participate in Working Group meetings, to review material prior to meetings, and to address questions raised and issues identified following the meetings. Working Group members may assign work to others within their organizations with appropriate technical or regulatory expertise on the topic.

(c) Working Group members are expected to engage in informal open discussion on a “without prejudice” basis. Although discussion in Working Groups will not be presented as evidence in the AESO’s tariff application proceeding, the AESO and participants may refer in their respective evidence to any conclusions they reach as a result of Working Group discussion. A participant or representative on any Working Group will not be precluded from participating in the AESO’s tariff application proceeding before the AUC. Neither stakeholders nor the AESO will be limited in any way from expressing views that may differ from those expressed in the Working Group. However, all participants are expected to engage in meaningful and transparent dialogue in the Working Groups.

(d) The activities of the Working Groups and related written documents will be communicated to stakeholders through postings on the AESO website, as appropriate. However, minutes of discussion and transcripts of conversations will not generally be prepared. All material will be assumed to be non-confidential unless identified otherwise. All such material will be available on the AESO website at www.aeso.ca by following the path Tariff ➤ Current Consultations ➤ 2010 Tariff. All stakeholders will generally have opportunity to comment on the material posted, as part of comment processes in the AESO’s general stakeholder consultation.

(e) Working Group conclusions will be considered by the AESO in developing proposals for its 2010 tariff application. The AESO’s 2010 tariff application will reflect decisions consistent with legislation, policy, and the AESO’s mandate, considering the input and advice provided by the Working Groups. The rationale for the AESO’s proposals will be included in the tariff application.

6 Deliverables

The AESO 2010 Tariff Consultation Working Groups will provide the following.

(a) Advice and expert comments on specific topics being considered as part of the AESO’s 2010 tariff application.

(b) Suggestions to improve the studies, analysis, rates, and terms and conditions that will comprise the AESO’s 2010 tariff application.
(c) Identification of legislation, policy, prior regulatory decisions, principles, precedent, and practices that are relevant to the topic being examined by the Working Group.

7 Principles

The activities of the AESO 2010 Tariff Consultation Working Groups will be consistent with the AESO’s mandate to prepare a tariff that is just and reasonable, and that is not unduly preferential, arbitrarily or unjustly discriminatory, or inconsistent with or in contravention of any applicable law.

Working Groups will consider topics in the context of an overall Alberta perspective that will improve the fairness, efficiency, clarity, and consistency of the AESO’s tariff.

8 Expenses

Working Group members are responsible for their own out-of-pocket expenses and time for participating in Working Group activities. The AESO will not reimburse participants for costs incurred due to involvement on a Working Group.

9 Recent AESO Tariff Decisions

Members of the Working Groups should, at a minimum, be familiar with discussion of the topic in recent AESO tariff decisions, which are listed below for convenience.

- EUB Decision 2005-132: AESO Review and Variation of Customer Related POD Charge (released on December 6, 2005)

Part 2 Independent System Operator and Transmission
Division 2 Independent System Operator Duties and Authority

Duties of Independent System Operator

17 The Independent System Operator has the following duties:

(a) to operate the power pool in a manner that promotes the fair, efficient and openly competitive exchange of electric energy;

(b) to facilitate the operation of markets for electric energy in a manner that is fair and open and that gives all market participants wishing to participate in those markets and to exchange electric energy a reasonable opportunity to do so;

(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....


Part 2 Transmission System Planning

Long term planning - 20-year plan

9 As part of its duties under section 17 of the Act, the ISO must

(a) prepare and maintain a long term transmission system outlook document that projects, for at least the next 20 years,

(i) the forecast load on the interconnected electric system, including exports of electric energy,

(ii) the anticipated generation capacity, including appropriate reserves and imports of electric energy required to meet the forecast load,

(iii) the timing and location of future generation additions,

(iv) the transmission facilities required to meet the forecast load, imports and exports of electric energy and anticipated generation capacity, including appropriate reserves, in a timely and efficient way,
Long term planning - 10-year plan

10(1) As part of its duties under section 17 of the Act, the ISO must

(a) prepare and maintain a transmission system plan in greater detail than the long term transmission system outlook document, that projects, for at least the next 10 years,

(i) the forecast load on the interconnected electric system, including exports of electric energy,

(ii) the anticipated generation capacity, including appropriate reserves and imports of electric energy required to meet the forecast load,

(iii) the timing and location of future generation additions,

(iv) the transmission facilities required to meet the forecast load, imports and exports of electric energy and anticipated generation capacity, including appropriate reserves, in a timely and efficient way,

(v) the transmission facilities required to provide for the efficient and reliable access to jurisdictions outside Alberta, and

(vi) other matters related to the items described in subclauses (i) to (v) that the ISO considers appropriate,

(b) update the transmission system plan periodically as required, but at least every 2 years, including updating the plan to restore the interties referred to in section 16, and

(c) make the transmission system plan, including the assumptions and supporting data on which the plan is based, and the updates made to the plan, available to the public, and file copies of them with the Board for information.

Part 3 Transmission System Criteria and Reliability Standards

Matters taken into account

15(1) In making rules under section 20 of the Act, and in exercising its duties under section 17 of the Act, the ISO must...

(g) make rules respecting the preparation of needs identification documents for, and the planning and processing of, enhancements or upgrades to transmission facilities that existed on August 12, 2004 for the purpose of providing transmission capacity to import or export electric energy to or from Alberta in
excess of the path ratings that existed on August 12, 2004 for those transmission facilities.

Restoring interties existing on August 12, 2004 to their path rating

16(1) In making rules under section 20 of the Act, and in exercising its duties under section 17 of the Act, the ISO must prepare a plan and make arrangements to restore each intertie that existed on August 12, 2004 to, or near to, its path rating.

(2) The plan to restore interties to their path ratings must specify how the ISO intends to restore and maintain each intertie to, or near to, its path rating without the mandatory operation of generating units.

(3) The plan to restore and maintain interties must be incorporated into and form part of the transmission system plan as soon as practicable.

Intertie projects

27(1) This section applies to the following:

(a) an intertie proposed to be constructed;

(b) an upgrade or enhancement to an intertie that proposes, or would result in, an increase to the path rating of the intertie.

(2) When the ISO prepares a needs identification document under section 34(1) of the Act for an intertie described in subsection (1), the needs identification document must

(a) contain the information required by section 11(3), unless the ISO determines that any of those matters are not required,

(b) describe the extent to which the ISO will make use of the proposed intertie to provide system access service,

(c) contain proposed agreements, arrangements, rates and terms and conditions for the ISO’s use of the intertie, and

(d) contain any other information that the ISO considers necessary in view of the nature of the proposed intertie.

(3) A person proposing an intertie to which this section applies must assist the ISO in preparing the needs identification document.

(4) The cost of planning, designing, constructing, operating and interconnecting an intertie to which this section applies must be paid by

(a) the person proposing the intertie, and
(b) other persons to the extent that they directly benefit from the intertie, based on the use described in the needs identification document approved by the Board, and then only to the extent permitted by the ISO tariff.

(5) A person proposing an intertie to which this section applies, in accordance with the ISO rules, must

(a) provide open access to market participants by auction or other transparent process, and file the terms and conditions respecting open access with the Board for information, and

(b) provide that the intertie be available in an open and non-discriminatory manner, similar to the access available to other transmission facilities.

(6) The ISO must include in the ISO tariff, rates and terms and conditions that include costs for use of the interconnected electric system, appropriate for the class of service provided to persons who use the intertie referred to in this section for import or export of electric energy to or from Alberta.

**Part 6 Transmission System Losses, Charges and Credits**

**Transmission system loss factors**

31(1) The ISO must make rules to

(a) reasonably recover the cost of transmission line losses on the interconnected electric system by establishing and maintaining loss factors

(i) for each generating unit,

(ii) for each export path or group of export paths, as those terms are defined in the ISO rules respecting line losses,

(iii) for each import path or group of import paths, as those terms are defined in the ISO rules respecting line losses, and

(iv) for any other opportunity service customer in respect of whom the ISO determines a loss factor is to apply, based on their respective locations and their respective contributions, if at all, to transmission line losses...

(e) subject to section 33, provide a means through the application of a single calibration factor to adjust the amounts paid by the application of the loss factor described in clause (c) so that

(i) owners of generating units,

(ii) importers and the exporters of electric energy, and

(iii) any other opportunity service customers referred to in clause (a)(iv),
are charged or receive a credit so that they pay the actual cost of transmission line losses.

Determination of transmission loss factors on and after January 1, 2009

36 On and after January 1, 2009, the loss factors under this Part must be determined so that

(a) the owner of a generating unit must pay location-based loss charges or receive credits,

(b) importers of electric energy must pay location-based loss charges or receive credits
   (i) determined in the same manner as for generating units, and
   (ii) determined at the point where the import path, referred to in section 31(1)(a)(iii), connects to the remainder of the interconnected electric system,

(c) importers and exporters of electric energy must pay transmission line loss charges representing the average level of losses incurred in transporting electric energy on an import path or export path referred to in section 31(1)(a)(ii) and (iii), and

(d) a person that receives opportunity service where the ISO determines that a line loss factor applies under section 31(1)(a)(iv) must pay losses or receive credits that are determined in a similar manner as the losses and credits determined for owners of a generating unit.

Part 7 Board Responsibilities

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 Board 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.

**Transmission Development Policy (December 22, 2003)**

2. **Background** (page 2)

Transmission development must also recognize that Alberta is part of, and connected to the rest of the North American electric grid. Inter-ties are an essential part of a competitive market both as a means to import power when needed, to export surplus energy, and to ensure that the competitive wholesale market functions effectively.

3. **Principles**

3.1. **Transmission – Foundation Principles** (page 3)

Adequate transmission is required to ensure that the electric system is reliable and efficient and to ensure that the competitive wholesale market functions effectively. Transmission development must recognize that Alberta is connected to a North American system. Inter-ties are an essential part of a competitive market both as a means to import power when needed and to export surplus energy.

The following principles summarize and further articulate the fundamental goal stated above.

6. Inter-ties are essential to a well-functioning market structure. Alberta is integrated with the electric systems of our neighbours. Transmission policy and the regulatory environment must facilitate open access to larger markets, while ensuring that Alberta’s needs are met.

7. The policy should support appropriate consideration of export projects including the benefits to Alberta consumers.

4. **Conclusions** (pages 9-10)

8. Transmission internal to Alberta should be reinforced so that under normal conditions, the existing inter-ties can import and export power on a continuous basis, in accordance with their design capability.

The design capability is defined as the maximum level at which the inter-ties can be operated, respecting NERC and WECC reliability criteria and without the use of must run generation.

Under normal conditions, the Alberta transmission system should be reinforced so that the BC Inter-tie is capable of transferring about 1,000 MW for exports subject to availability of generation RAS schemes and about 800 MW for imports subject to suitable load RAS schemes. Imports in excess of 800 MW on the BC Inter-tie require more careful consideration since they may place the Alberta system at considerable risk. The Saskatchewan Inter-tie should be capable of transferring 150 MW for import and export.
Inter-ties are an essential part of a competitive market both as a means to import power when needed, and to export surplus energy and to support effective functioning of the wholesale market. Without such capabilities, market signals and wholesale prices are distorted and unreflective of true market conditions. Since the ability of inter-ties to exchange electricity in both directions (i.e. import and exports) is essential to a robust wholesale market and a reliable electric system, the cost for internal reinforcements and RAS arrangements to allow the inter-ties to function as designed will be allocated to load.

It is recognized that a combination of market design and exercise of market power have constrained the use of inter-ties through BC. Alberta will continue with its efforts to ensure compatibility with its neighbouring jurisdictions and to address access issues with BC Hydro transmission and the Pacific Northwest. Alberta Energy will also continue to participate in RTO and related discussions to ensure Alberta's interests are represented appropriately. However, due to the length of time needed for transmission upgrades, required upgrades to the internal transmission network must not be held in abeyance awaiting resolution of access issues with BC/US markets.

**Inter-tie Pricing**

The current practice of charging exporters who use non-firm transmission service (i.e. opportunity service) is appropriate. The opportunity export tariff will continue to recover a portion of the embedded costs of transmission wires, losses and ancillary services, while respecting the established practices for inter-regional electricity trade. Such non-firm transmission service should be priced at a discount from the firm transmission service rate. Firm export service may also be developed, with the expectation that this service will be priced at the same level as firm service in Alberta.

Alberta Energy also confirms that import variable charges will be removed coincident with discontinuation of the STS variable energy charge for generators. Loss charges will continue to apply to exporters and importers.

9. Projects primarily intended for export should be considered on a case-by-case basis. Pricing for such projects would normally be paid by the project beneficiaries (i.e. the exporters). Where residual benefits to the internal grid are demonstrated, consumers may fund system upgrades, in a manner consistent with the benefits.

The ISO will be responsible for bringing forward such applications to the EUB in conjunction with project proponents. For dedicated export projects, it is expected that project proponents will be responsible for the costs. The project proponents will be responsible to demonstrate any residual benefits to the Alberta market. Upon demonstration of these benefits, commensurate sharing of costs may occur with load customers in Alberta.

The regulated framework for transmission should also allow development of “merchant” transmission lines, involving Direct Current (DC) lines to export power over long distances and across borders on a fee-for-service basis. Open access to merchant transmission lines should be available to market participants subject to an auction or other transparent process.
1. Executive Summary

Short Term Adequacy:… (page 3)
After extensive consultation with stakeholders during one-on-one meetings and STA working group discussions, the common stakeholder view was that enhancing existing market designs and rules would address STA concerns and that implementation of a day-ahead market (DAM) design was not necessary at this time. The Department agrees with this conclusion. As such, the Department recommends refinements to the wholesale market structure that will improve supply visibility and stability for the ISO and thereby enhance system reliability and price fidelity. Specific recommended refinements address:…

- Treatment of imports in the same manner as intra-Alberta generators

Other Market Issues:… (page 4)
Interties: To the extent possible, industry suppliers with import capacity should be treated the same as intra-Alberta generators. The Department, therefore, recommends that all imports be required to offer energy and allowed to set Pool price if they are able to respond to an intra-hour energy market dispatch.

4.3.3. LTA [Long Term Adequacy] Options

Other Adequacy Tools (page 32)
Transmission interconnections with neighbouring jurisdictions are essential to a well-functioning power market as they support reliability, price stability, generation development and continued economic growth in Alberta. Albertans benefit from these interconnections by having the ability to import or export power as needed.

The Transmission Policy and Regulation provides certain direction regarding interties. The ISO is required to create long term plans including consideration of interties and is also provided with direction to reinforce the transmission system internal to Alberta so that existing intertie capacity is restored to its design path rating. The Transmission Policy and Regulation also provides a framework for the development of privately funded merchant transmission lines for import and export of electric energy. This approach is starting to generate significant interest in the industry.

Additional intertie capacity may provide an alternative to address long term adequacy. For example, a transmission adequacy criteria could specify that sufficient intertie capacity be available to allow transfers of up to 20 per cent of system peak load (i.e. ~ 2000 MW). This could allow greater exports from Alberta which could stimulate generation development in the province and also enhance system adequacy. Such exports could be recallable in times of system supply shortages.

4.3.4. Recommendations (page 34-35)

Recommendation: The Department considers that strong interconnection capacity with neighbouring jurisdictions may, in the long term, contribute to address or significantly mitigate long term adequacy concerns for Alberta. The Department recommends that the ISO, as part of its obligation to assess and ensure reliability, consider and evaluate the merits of additional intertie capacity, including new interconnections, in its long term plans. Additional intertie
capacity and interconnections may allow greater exports from Alberta which could stimulate
generation development in the province and also enhance system adequacy. Such exports
could be recallable in times of system supply shortages.

4.4.3. Interties (pages 38-39)

Export Capacity

Transmission interconnections with neighbouring jurisdictions are essential to a well-functioning
power market as they support reliability, price stability, generation development and continued
economic growth in Alberta. Albertans benefit from these interconnections by having the ability
to import or export power as needed.

As noted previously, the Transmission Policy and Regulation provide certain direction regarding
interties. The ISO is required to create long term plans including consideration of interties and is
also provided with direction to reinforce the transmission system internal to Alberta so that
existing intertie capacity is restored to its design path rating. The Transmission Policy and
Regulation also provides a framework for the development of privately funded merchant
transmission lines for import and export of electric energy.

Recommendations

The Department recommends that the ISO evaluate additional tie-line capacity with
neighbouring systems in its 20-year Transmission Outlook documents and plans. Supporting
export capability of surplus energy could stimulate generation development in the province
which would directly enhance system adequacy and reliability. Exports would be recallable in
times of system supply shortages.

Seams Issues

There are a number of seams issues with neighbouring jurisdictions that have been and
continue to be examined, the most pressing of which for several stakeholders is the impact
imports have on Pool price.

Currently, import bids are required to be offered in at $0/MW·h and do not set Pool prices. This
requirement was imposed because imports are unable to respond within the hour to the SMP,
due to inter regional scheduling practices. Allowing imports to set price would better reflect the
true cost of energy. This issue could be addressed by simply allowing imports to set price when
they are the marginal unit, and to be price-takers when not the marginal unit. One potential
concern for this option is that it could give importers greater pricing flexibility and an unfair
advantage over in-province generation. A second concern is the system operator’s ability to
forecast, for scheduling and dispatch purposes, whether imports or exports would be in merit.

Recommendations

To the extent possible, imports are to be treated the same as intra Alberta generators:

- Owners of “firm transmission” must offer energy on a day ahead basis – this energy will be
taken into account in the AESO’s reliability assessment and must be delivered if issued an
energy dispatch
- Energy to be delivered on “non-firm transmission” may be offered up to T-2 and must be
delivered if issued an energy dispatch
• Imports will be allowed to set Pool price if they are able to respond to an intra hour energy market dispatch – in the near term this will mean that importers wishing to set Pool price will have to make arrangements for intra Alberta generation to accept an energy market dispatch during the delivery hour
• Imports are subject to the T-2 “lockdown” for price restatements
• Imports with firm transmission must respond to a commitment dispatch.
6.5 Supply Transmission Service (STS) Rate Design

The STS rate is the portion of the AESO tariff used to recover certain costs from generators. The costs recovered from generators are line losses (which are based on location specific loss factors and pool price), and an interconnection charge (known as the Regulated Generating Unit Connection Charge, or RGUCC).

The AESO did not include an explicit section addressing the STS rate in the Application. Rather, the AESO stated that its STS was being reduced by 6.0%\(^2\), and included an updated STS rate schedule in its proposed rate schedules.\(^3\)

The rate schedule updates included a revised RGUCC charge of $303.88/MW/month, and precise wording which defined that location specific loss factors would be defined in accordance with ISO Rule 9.2.\(^4\)

The AESO argued that it had provided the derivation of the RGUCC value in response to BR.AESO-18 (a), and that other than the ADC proposal that some wires costs, related to system optimization to reduce losses, be included in the STS tariff, no parties had raised any concerns or brought forth an alternate STS rate design.\(^5\)

The AESO STS rate design has changed very little over the rate approved in Decision 2005-096. Further, the AESO provided the derivation of the RGUCC in BR.AESO-18(a).

The Board has reviewed this calculation and considers the AESO RGUCC appears to be reasonable. Further, the Board agrees with the AESO that the location specific loss factors used to calculate line losses are to be determined in accordance with the ISO Rule 9.2. The Board considers RGUCC related matters in section 8.7 of this Decision.

The Board has provided its reasons for rejecting the ADC proposal to add wires related system optimization costs to the STS rate in section 2 (Legislative Requirements) of this Decision.

The Board therefore approves the AESO STS rate contained in the STS rate schedule included in section 7 of the Application.

7 PHASE 2 MATTERS - EXPORT AND IMPORT RATES

7.1 XTS Rate

The AESO proposed a “non-recallable” rate (rate XTS) that would apply to customers exporting electric energy from the AIES over the Alberta-British Columbia or Alberta-Saskatchewan interties.\(^6\) In Decision 2005-096, the Board encouraged the AESO to continue stakeholder

---

\(^2\) Ex. 005, Application, Section 4, Table 4.0.1, p. 2
\(^3\) Ex. 008, Application, Section 7, p. 26
\(^4\) From the AESO website, www.aeso.ca: The Independent System Operator (ISO) Rules are designed to promote a fair, efficient and openly-competitive wholesale market for electricity in Alberta. The ISO is the term used in the Electric Utilities Act to refer to the operating company the Alberta Electric System Operator or AESO.
\(^5\) AESO Argument, p 47
\(^6\) Ex. 008, Section 7 of the Application, p. 12 of 129
discussions with interested parties towards the potential development of firm import and export rates.\textsuperscript{257}

The AESO based the proposed rate XTS on its proposed DTS rate. This meant that the proposed rate XTS reflected DTS rate components (except for exclusion of the POD charge from rate XTS) expressed on a usage basis.\textsuperscript{258} Minor revisions were subsequently made to the proposed XTS rate schedule in an AESO errata filing.\textsuperscript{259}

The proposed XTS rate would require a minimum contract term of 1 year. The AESO indicated that it would consider capacity contracted under the XTS rate in its transmission system planning decisions.\textsuperscript{260} The AESO also noted that while customers would be required to contract for XTS capacity for the full contract term, capacity would only be available in hours in which Available Transfer Capacity (ATC) exists to accommodate the capacity. The AESO indicated that it did not intend to charge customers under rate XTS for any hour in which the ATC was not available to accommodate scheduled transfers.

TCE submitted that the AESO’s proposed XTS rate should be rejected because it would not properly reflect cost causation and would not provide an appropriate level of firmness of service.

Depending on the definition used, TCE noted that during August to December of 2006, ATC was not available for 25% to 40% of on-peak hours. It further noted that during the January to July period, ATC unavailable for 90% of hours. TCE submitted that while exports booked under rate XTS would have a higher scheduling priority than Rate XOS, rate XTS effectively provided the same level of service as Rate XOS except during times of limited availability rather than complete unavailability of ATC. TCE argued that the 20-40% of hours when ATC tends not to be available may be the most profitable hours for exports, such that the AESO’s proposed XTS rate would not be appealing to either exporters or their counterparties in light of the opportunity service rate already available. TCE argued that if a so-called firm service is not always available, it is really only an opportunity service. As such, there would be no reason for an exporter to pay a premium beyond the cost of XOS rates except to obtain a higher priority than other opportunity exports.

TCE expressed concern with the AESO’s proposal that commitments for firm service would be used as a signal to provide additional capacity on the transmission system. TCE also expressed concern with the absence of a “use it or lose it” provision in the rate to avoid potential abuse of rate XTS for the purposes of blocking export transactions from Alberta.\textsuperscript{261}

TCE expressed concerns about issues of consistency with other jurisdictions (seams issues)\textsuperscript{262} and was not confident that these issues could be resolved to the satisfaction of the parties outside of the tariff. For this reason alone, TCE submitted that approval of rate XTS would be premature. Powerex and IPPSA expressed similar concerns.

\begin{footnotesize}
\begin{itemize}
\item \textsuperscript{257} Ex. 005, Section 4.8 of the Application, p. 44; Decision 2005-096, p. 35
\item \textsuperscript{258} Ex. 005, Section 4.8.1 of the Application, page 46, Ex 008, Section 7 of the Application, pp. 12-13 of 129
\item \textsuperscript{259} Ex. 382, AESO Errata Filing no. 2 dated May 10, 2007
\item \textsuperscript{260} Tr. Vol. 3, p. 601
\item \textsuperscript{261} Ex. 242, TCE Evidence, p. 46, cited in Powerex Argument at p. 26
\item \textsuperscript{262} Powerex-TCE 8 and Powerex-TCE 9; see also Exhibit 126, TCE.AESO-52(c), cited in Powerex argument at p. 26
\end{itemize}
\end{footnotesize}
TCE submitted rate XTS should be denied and the AESO should be directed to work with exporters to develop a firm export rate. TAU, Powerex and IPPSA made similar submissions.

Powerex noted that the design of rate XTS relied on the same cost basis as Rate DTS (except for the exclusion of the POD charge from rate XTS). However, Powerex noted that the level of ATC currently available is not sufficient to offer firm expert service on the British Columbia- Alberta intertie line.\textsuperscript{263} It also submitted that since rate DTS would remain a higher priority service than rate XTS, and since the AESO has not committed to dispatching out-of-merit generation to maintain rate XTS service (as it would for DTS service), the proposed rate XTS offered a lower quality service but at full firm service rates.

With regard to the AESO’s assertion of 80% availability of 100MW ATC, Powerex argued that 80% availability is poor even for an interruptible service, and much less so for a firm service. Powerex noted that the AESO had not guaranteed that it would dispatch Transmission Must Run (TMR) to meet the needs of XTS customers (as it would for DTS service). Powerex argued that instead, the AESO only indicated that using TMR for this purpose was still under discussion in its ATC working group. Absent such assurances, Powerex submitted that it would not be reasonable to set firm export rates at a level equivalent to domestic service rates.

IPPSA argued that the AESO’s proposed rate XTS was flawed for several reasons, including that the level of firmness was not acceptable, given the evidence of the limited availability of ATC. It also submitted that the market for XTS service was not fully developed and that the proposed cost of rate XTS would likely not justify its use. IPPSA also questioned the appropriateness of a one year commitment period in the absence of a developed market. IPPSA considered that the AESO was attempting to sell an interruptible service under a firm service rate.

TAU submitted that the AESO’s approach of aligning the XTS and DTS rates appeared to be flawed since the postage stamp requirements set out in subsection 30(3)(a) of the EUA do not apply to exporters.

In reply, the AESO argued that whereas several parties had opposed the approval of the proposed XTS rate, no party had offered an alternative proposal. The AESO noted that given the positions of interveners, parties would be unlikely to use the proposed XTS rate, and that elimination of the rate from the 2007 tariff would likely have little practical impact. However, the AESO submitted that its proposed XTS rate was reasonable and cost based and noted that participants in this proceeding would not represent all potential users of the service.

The AESO stated that it would expect to consult with stakeholders on modifications to the firm export rate, if required, as and when continuous availability of export capacity becomes more likely. Given that it is unknown when such export capacity may become available, the AESO submitted that it would be premature for the Board to provide specific direction regarding the development of a firm export tariff.

TAU argued that the availability of at least 100 MW of ATC for about 80% of the time during the last quarter of 2006 was significantly different from the availability and nature of DTS

\textsuperscript{263} Tr. Vol. 3, p. 599
service. TAU submitted that Rate DTS service levels should comply with the so-called “100% / 95% capability” set out in section 15(1)(e) of the Transmission Regulation. TAU noted that section 16 of the 2007 Transmission Regulation requires the restoration of intertie capacity, and that such restoration by 2009 is doubtful.

In light of these considerations, TAU submitted that the approval of a firm rate for export service premised on a cost allocation matching that of firm DTS service would not reflect the facts of the system and would therefore be inappropriate. TAU also expressed concern that, if adopted, the AESO’s proposed XTS rate would become the status quo for any further consideration of a firm export service rate. 264

The Board will assess the issues raised by parties in respect of the proposed XTS rate first by reviewing the legislative requirements, and second by considering whether the level of reliability of the export service might justify approval of the rate, in light of the seams and implementation issues raised by interveners.

7.1.1 Legislative Requirements

The Board considers that the proposed rate XTS must be assessed bearing in mind three possible situations: restoration of an existing export intertie path to its rated capacity, establishment of a new intertie, and expansion or upgrade of an existing intertie to a rating that exceeds its rated capacity.

With regard to restoration of an intertie to its rated capacity, the Board stated in Decision 2005-096 that:

The Board has reviewed Subsection 8(1)(g) of the Transmission Regulation, dealing with the restoration of the intertie to its rated capacity. The Board considers that the AESO has an obligation pursuant to the Transmission Regulation to make rules and to take measures to expand or enhance the transmission system in order to restore the path rating of the interconnections however, the regulation does not impose a time frame nor does it dictate the method in which this must be achieved. This provision is not a required matter to be included in the tariff under the regulation. Rather, it is part of the rule making authority conferred on the AESO. The Board therefore does not consider that the AESO is in breach of this section of the regulation should it choose not to pursue the development of import and export tariffs to the extent desired by parties in this proceeding. The Board notes, with encouragement, the fact that the AESO has invited significant stakeholder consultation in this process, as shown by the evidence in this proceeding. 265

Subsection 8(1)(g) of the 2004 Transmission Regulation, 266 which was in effect at that time, provided that:

8(1) In making rules under section 20 of the Act, and in exercising its duties under section 17 of the Act, the ISO must

…

264 TAU Reply Argument, p. 4
265 Decision 2005-096, p. 35.
266 Transmission Regulation, AR 174/2004
(g) make arrangements for the expansion or enhancement of the transmission system so that, under normal operating conditions, the transmission system interconnections with jurisdictions outside Alberta can import and export electricity on a continuous basis, at or near the transmission facility's path rating.

Section 16 of the 2007 Transmission Regulation sets out the obligation of the AESO to restore existing interties to their path ratings. This provision reads as follows:

16(1) In making rules under section 20 of the Act, and in exercising its duties under section 17 of the Act, the ISO must prepare a plan and make arrangements to restore each intertie that existed on August 12, 2004 to, or near to, its path rating.

(2) The plan to restore interties to their path ratings must specify how the ISO intends to restore and maintain each intertie to, or near to, its path rating without the mandatory operation of generating units.

(3) The plan to restore and maintain interties must be incorporated into and form part of the transmission system plan as soon as practicable.

While subsection 16(3) of the 2007 Transmission Regulation now specifies that the AESO must prepare a plan and make arrangements for existing intertie path rating restoration “as soon as practicable,” the Board finds that the regulation does not impose a specific time frame nor does it dictate the method in which this must be achieved. The Board finds that this provision is not a required matter to be included in the tariff under the regulation, but rather is part of the rule making authority conferred on the AESO. The Board considers that the AESO is not in breach of this section of the regulation should it choose not to pursue the development of import and export tariffs to the extent desired by parties in this proceeding.

With respect to the allocation of costs related to path restoration intertie projects, this matter was addressed in Decision 2005-096 on the basis of principles set out in the 2003 discussion paper entitled “Transmission Development: The Right Path for Alberta” (the Transmission Development Policy or TDP). The Board stated in Decision 2005-096, with reference to generator remedial action schemes (GRAS) that:

In light of the foregoing, therefore, the Board will not direct the AESO to implement a GRAS as part of this Decision. However, the Board does agree with TCE that the Transmission Development Policy clearly indicates that the costs of internal reinforcements and RAS arrangements necessary to allow the interties to operate at their design capacity are to be allocated to load, irrespective of whether the RAS arrangement is export or import related.

The Board finds that the rationale for allocating those costs to load applies beyond GRAS, and applies equally to restoration of an intertie within the meaning of section 16 of the 2007 Transmission Regulation. Allocating these costs to load is also consistent with the Transmission Development Policy, which indicated that the cost for internal reinforcements and RAS arrangements to allow the interties to function as designed are to be allocated to load.

---

267 Ex. H-008
268 Decision 2005-096, p. 37
269 Ex. H-008, p. 9
The Board finds that in the context of restoration of interties within the meaning of section 16 of the 2007 Transmission Regulation, both the cost of facilities and operational measures on the interties themselves as well as any internal reinforcements within the Alberta transmission system are to be included within the set of costs allocated to rate DTS rather than being specifically identified and allocated to rate XTS.

The Board further notes that while the AESO has indicated that it intends to use rate XTS contract sign-ups as a signal or trigger for transmission system planning purposes, this approach appears to be inconsistent with the legislative and regulatory framework in at least two major respects. In particular, section 16 of the 2007 Transmission Regulation places an obligation on the AESO to make arrangements to relieve any constraints on the transmission system that may be preventing full utilization of the existing interties to their designated path ratings. Accordingly, the Board finds that the AESO’s obligation to restore existing interties to their path ratings is not tied to contracting for firm export service by AESO customers.

In contrast, the Board is concerned that relying on contracting for rate XTS as an indicator of need could result in the construction of new system capacity for the primary benefit of importer or exporters that would not otherwise be built. In particular, the Board is concerned that if the aggregate firm export service capacity contracted for by customers exceeded the capacity required to restore existing interties to the path ratings, the costs of such additional system capacity could be borne by DTS customers without the regard to a benefits test discussed in both subsection 27(4) of the 2007 Transmission Regulation and the Transmission Development Policy.

With regard to new interties, or upgrades or enhancements to an intertie that proposes or would result in an increase to the path rating (each, “non-restoration” interties), section 27 of the Transmission Regulation is applicable. This provision reads (in part):

**Intertie projects**

27(1) This section applies to the following:

(a) an intertie proposed to be constructed;

(b) an upgrade or enhancement to an intertie that proposes, or would result in, an increase to the path rating of the intertie.

...

(4) The cost of planning, designing, constructing, operating and interconnecting an intertie to which this section applies must be paid by

(a) the person proposing the intertie, and

(b) other persons to the extent that they directly benefit from the intertie, based on the use described in the needs identification document approved by the Board, and then only to the extent permitted by the ISO tariff.

(5) A person proposing an intertie to which this section applies, in accordance with the ISO rules, must

---

270 Tr. Vol. 3, pp. 601-602
(a) provide open access to market participants by auction or other transparent process, and file the terms and conditions respecting open access with the Board for information, and

(b) provide that the intertie be available in an open and non-discriminatory manner, similar to the access available to other transmission facilities.

(6) The ISO must include in the ISO tariff, rates and terms and conditions that include costs for use of the interconnected electric system, appropriate for the class of service provided to persons who use the intertie referred to in this section for import or export of electric energy to or from Alberta.

Subsection 27(4)(a) provides that the costs of non-restoration intertie projects are to be borne by the person proposing the intertie. Subsection 27(4)(b) further provides that such costs may be shared with other persons only to the extent that they directly benefit from the intertie, and then only to the extent that the benefit is identified in a Board approved needs identification document, and only to the extent permitted by the AESO tariff. The Board considers that the burden of demonstrating residual direct benefits from a non-restoration intertie project within the meaning of section 27(4) of the 2007 Transmission Regulation generally lies with the person proposing the intertie.

Furthermore, while subsection 27(6) of the regulation requires the AESO to include rate and terms and conditions for the use of the Alberta interconnected system to access non-restoration intertie facilities for the import or export of electric energy to or from Alberta, those rates and terms and conditions must be “appropriate for the class of service.”

The Board considers that a rate appropriate for this class of service must be determined with regard for cost allocation principles set out in subsection 27(4). The Board finds that the proposed XTS rate does not comply with subsection 27(4) or subsection 27(6) criterion by virtue of the fact that the different cost sharing principles applicable to intertie path restoration costs and non-restoration intertie project costs are not appropriately reflected in the proposed rate. The Board finds that XTS rate must be denied on this basis.

7.1.2 Additional Issues Raised By Parties

Several of the concerns raised with the proposed Rate XTS give rise to additional concerns.

The Board agrees with the observations of several parties that the curtailment priority assigned to service under rate XTS and the anticipated availability of sufficient ATC during the term that the tariff is expected to be in effect is not consistent with the notion of a firm service. In general, the Board agrees with the view expressed by TAU in its reply argument that the availability of a firm service should reflect the standard set out in section 15(1)(e) of the 2007 Transmission Regulation. The Board does not agree with the AESO’s suggestion that even though export intertie ATC is not likely to be fully available during the anticipated term of the tariff, the level of service that would be available for potential users of rate XTS would justify establishment of a rate described as a firm service rate.
Although Powerex commented on the absence of an AESO commitment to dispatch generators out-of-merit to the extent necessary to provide a firm export service,\textsuperscript{271} the Board considers that this is a matter within the AESO’s rulemaking powers pursuant to section 17 of the \textit{Transmission Regulation.} Accordingly, the Board considers that it is not necessary or appropriate for the Board to direct the AESO to incur out-of-merit costs to ensure that truly firm export service rate is available during the expected effective period of the tariff.

The Board recognizes that the curtailment priorities stated in the XTS and XOS rate schedules attach a moderately higher degree of firmness of service to rate XTS than rate XOS,\textsuperscript{272} and that for this reason Rate XTS would tend to have a somewhat higher value to customers than Rate XOS. The Board does not consider that, absent legislative considerations, this would have been a sufficient basis upon which to have approved proposed rate XTS, given the seams issues and current administrative complexity of implementing such a rate.

A concern raised by TAU was that any firm export service rate that might be approved by the Board might be viewed as the “status quo” for the purposes of addressing seams issues and other export service business practices.\textsuperscript{273} The Board considers that withholding approval of proposed rate XTS would provide greater freedom to the AESO and parties to address any issues that may be raised in future stakeholder discussions and to best align the nature of export services offered with the costs allocated to the service within a proposed AESO tariff rate.

In reply argument, the AESO stressed the value of continuing to develop an Open Access Same Time Information System (OASIS) or other similar system, regardless of whether its proposed rate XTS is approved. Given that certain rates approved in this Decision may depend on completion of an OASIS or similar system, nothing in this Decision requires the AESO to offer rates approved in this Decision prior to implementation of the OASIS system. If for this reason the AESO does not intend to offer one or more rates approved in this Decision, the Board directs the AESO to identify those rates at the time of its refiling application.

As cost causation is strongly related to whether the service is curtailable or essentially firm, the Board encourages the AESO to resolve the anticipated level of firmness of the service to be provided, prior to proposing an export rate in future tariff applications.

\section*{7.2 Import Export Opportunity Service Rates}

In the Application, the AESO noted that in consultations, some stakeholders requested an extensive selection of export rates (hourly, daily, weekly, monthly, and annual versions, for both non-recallable and opportunity service). However, the AESO stated that it understands that in neighbouring jurisdictions, the majority of export transactions occur on hourly, monthly, and annual rates. Therefore in the Application, the AESO proposed hourly and monthly opportunity export rates (proposed rates XOS 1 Hour and XOS 1 Month). The proposed XOS rates would replace the current EOS rate and would be applicable to customers who export electricity from the AIES over the Alberta- British Columbia or Alberta-Saskatchewan inter-ties.\textsuperscript{274}

\begin{footnotesize}
\begin{itemize}
  \item Powerex Argument, p. 25
  \item Ex 008, Application, section 7, rate schedules at pages 12, 14, 16 of 129
  \item TAU Reply Argument, p. 4
  \item Ex. 008, Application, Section 7, pp. 14-17 of 129 (Rate XOS 1 Hour and Rate XOS 1 Month)
\end{itemize}
\end{footnotesize}
Export rate component charges are proposed to be based on similar components as for the DTS rate. Similar to the AESO’s DOS rate proposals, the AESO proposed that all export rate components will be charged on a usage ($/MWh or percentage of pool price) basis. The AESO therefore converted all components of its 2007 DTS revenue requirement into usage charges as if all were to be recovered on such a basis from all DTS customers. The fixed and variable component of each DTS rate component was then examined to determine which costs should be included in export rates.

### 7.2.1 Export Opportunity Service (XOS) Rates

The AESO proposed that export opportunity service Rates XOS 1 Hour and XOS 1 Month be recallable services similar to DOS rates (DOS 7 Minutes and DOS Term). The AESO noted that all scheduled export capacity must be confirmed at 20 minutes before the hour in accordance with AESO Operating Policies and Procedures (OPPs). The AESO stated that XOS capacity will be curtailed immediately prior to curtailment of opportunity domestic loads.

The XOS rates were designed to recover all variable costs and also a contribution to fixed costs, to reduce the average level of rates charged to other customers. The resulting costs attributable to Rate XOS 1 Hour and to Rate XOS 1 Month were presented in the Application.

TCE submitted extensive evidence on export rates. TCE considered that in its pricing of export rates, the AESO had incorrectly assigned fixed costs that are allocated on the basis of energy as if they were true variable costs that were properly allocated by energy. It also considered that the AESO allocated too many operating reserve costs to opportunity exports. TCE stated if cost of service was the main driver for pricing opportunity export rates, there would be a price reduction in the export opportunity rates. Based on its value of service criterion, TCE considered that an increase in export opportunity rates was required. TCE maintained the proper pricing of opportunity exports required an incremental or marginal cost analysis, combined with a value of service adjustment, to determine the appropriate contribution to fixed costs to be charged to the opportunity rate class. TCE proposed XOS 1 Hour and XOS 1 Month rates that are 10% and 20% respectively higher than the current EOS rate.

The AESO also noted TCE suggested black start services should not be attributed to XOS rates. The AESO considered that all services benefit from the ability to restore electrical supply in a timely manner on the transmission system in the unlikely event of a blackout. Black start services are considered a variable costs charged to DTS customers as a usage ($/MWh) charge. The AESO submitted it was reasonable to include that charge in the XOS rates. The Board agrees with, and approves, the allocation of blackstart services costs to the XOS rates on this basis.

---

275 Ex. 005, Application, Section 4, Table 4.8.2, p. 46
276 Ex. 005, Application, Section 4, Table 4.8.1, p. 45
277 Ex. 005, Application, Section 4, p. 48, lines 43-44
278 Ex. 005, Application, Section 4, Tables 4.8.4 and 4.8.5, pp. 48-49
279 Ex. 005, Application, Section 4, p. 49
280 TCE Evidence, pp. 33-46 & Appendix H
281 TCE Evidence, p. 36, Figure 4
282 Ex. 242, TCE Evidence, p. 46, lines 9-15
With respect to operating reserve costs, TCE maintained that the very nature of an opportunity service that it is only available when DTS customers are not otherwise using the bulk transmission system. TCE considered that the system planners do not plan for opportunity loads, and that opportunity loads have not created any embedded transmission system costs but that the AESO’s calculation of the reserve charge to opportunity service appears to involve embedded costs. TCE noted the AESO explained that significant reserves were required even if there are no opportunity sales.

TCE explained that it undertook an analysis of the 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, TCE maintained 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, TCE adopted this conservative assumption. Even with this assumption, TCE found that only 9% of the export energy will potentially be required for spinning reserves. TCE also assumed that 9% is also a reasonable estimate of the requirement for supplemental and regulating reserves. TCE recommended that exports should be allocated costs for 9% of the operating reserves that would be allocated to a firm load customer on a per KWh basis. This results in a reduction of the operating reserve charges from $2.29 per MWh to $0.21 per MWh.

The AESO maintained that in proposing that the XOS rates be allocated only 9% of the operating reserve costs that are allocated to rate DTS, TCE misunderstood the AESO’s operating reserve requirements. In an undertaking to TCE, the AESO confirmed that all export energy will require additional operating reserves, to a level similar to that required for firm load demand. The AESO explained that it regularly procured operating reserves as part of its ordinary requirement to support export services. The AESO submitted that simply because Part 2 of the XOS rates allows an incremental charge to be levied against export customers, at the discretion of the AESO, this should not preclude the inclusion of a standard charge for these services being built into Part 1 of the XOS rate.

Powerex, IPPSA and TAU generally supported the concerns of TCE. Powerex in particular submitted extensive argument on the proposed XOS 1 Hour rate, noting that the system was not planned to accommodate opportunity sales. Therefore opportunity sales should not be assigned any of the fixed costs incurred to expand the system. With respect to operating reserves, Powerex submitted that the AESO should charge only the incremental costs of reserves and maintained that the current wording in the tariff is appropriate. Powerex accepted the recommendations of TCE with respect to XOS 1 Month.

---

283 Ex. 242, TCE Evidence, Appendix F, p. 5, lines 31-33
284 Ex. 005, Application, Section 4, Table 4.7.1, p. 40 and TCE Evidence (Ex. 242) p. 42
285 Ex. H-022, where AESO’s Operating Policy and Procedure 402 is discussed.
286 TCE Argument, pp. 55-56, also Ex 242, TCE Evidence, p. 42
287 Ex. H-022, Undertaking No. 3
288 Powerex Argument, p. 33
289 Powerex Argument, p. 38
The Board considers that opportunity service should be priced at no less than incremental variable cost of providing the opportunity service, and that opportunity service rates should also reflect the value of the opportunity service to the customer.

The two primary areas of disagreement among parties with respect to pricing of opportunity service relate to the AESO’s determination of variable or energy related costs as a result of its proposed A&E methodology and the AESO’s determination of reserve costs.

With respect to the determination of the variable or energy related portion of wires costs allocated to opportunity service, the Board has in section 5.4.1 of this Decision rejected the use of the A&E methodology and directed a much lower energy related classification in the DTS rate. The finding regarding the lower energy classification must also be reflected in the pricing of export opportunity services to ensure that such opportunity service rates will, at minimum, be priced above variable cost. This acknowledges that a rate priced below variable cost would be subsidized by domestic customers, which is not in accordance with the principle of cost causation.

Incorporating the Board’s findings with respect to the A&E method results in a significant reduction in the minimum charge. By way of comparison, the figures presented by the AESO in the Application for the variable costs of connecting to the system are based upon the AESO’s proposed classification of costs using the A&E method. This resulted in approximately 50% of wires costs being classified as energy related. The energy classification directed by the Board, however, is to result only in 18% of wires costs being classified as energy. The Board therefore expects the $2.42/MWh shown by the AESO in Tables 4.8.4 and 4.8.5 of the Application as amount of variable cost to be allocated to opportunity service to drop to less than $1/MWh. The Board has also reviewed the revised Schedule 5.8 provided by TCE in its evidence and notes that TCE’s calculations may closely approximate what the Board’s cost of service based allocation might be, for the purposes of establishing a minimum charge.

With respect to the allocation of reserve costs to opportunity service, the AESO has performed a calculation that allocates an amount equal to the embedded cost of reserves to opportunity service. The Board considers this to be inappropriate as opportunity service should only be allocated incremental costs. Powerex has advocated that no direct costs for reserves be allocated to opportunity service. The Board does not consider this approach will reasonably recover the appropriate amount of cost. The Board considers the most credible evidence regarding the allocation of reserve costs for the purpose of determining the minimum charge to be that of TCE. TCE’s calculations were performed on an incremental basis, and the Board considers they most appropriately represent the costs incurred to provide opportunity service. The pricing of reserves as calculated by TCE, along with the discretion afforded to the AESO by the current wording in the existing tariff, will in the Board’s view result in recovery of the incremental costs incurred to provide opportunity service.

---

290 Ex. 005, Application, Section 4, p. 49, Tables 4.8.4 and 4.8.5
291 Ex. 005, Application, Section 4, p. 48, item (a) and p. 46, Table 4.8.2
292 AESO calculation based on 50% energy related, if reduce to 18% calculation is (.18/.50)*$2.42<$1
293 Ex. 005, Application, Section 4, Table 4.7.1, p. 40
294 TCE evidence, Figure 4, p. 36
Based upon the calculations provided by TCE, the incremental costs assigned to opportunity export services for the purpose of setting a minimum charge is below the current EOS Rate. However, as stated above, opportunity rates should also reflect value of service.

In its evidence, TCE proposed an XOS 1 Hour Rate with a price 10% higher than the current EOS Rate and an XOS 1 Month Rate 20% higher than the current EOS Rate. As it is evident that TCE’s proposed rates would exceed the incremental costs associated with opportunity export service, the Board considers that the rates proposed by TCE provide reasonable measure of the value of these services and would make a contribution to fixed transmission wires costs. The Board also notes that it has allowed the addition of black start costs to opportunity rate costs. The Board considers these costs to be minimal, however, and can be recovered within the rates proposed by TCE.

Therefore, in accordance with figure 4 on p. 36 of TCE’s evidence, the Board finds that the minimum charge in Rate XOS 1 Hour is to be set at $3.98 per MW/h and that Rate XOS 1 Month is to be set at $4.36 per MW/h. The AESO is directed to make all necessary adjustments to its export opportunity rate schedules and any associated T&Cs to reflect the above findings at the time of its refiling application.

### 7.2.2 Import Opportunity Service (IOS) Rate

The AESO stated that in stakeholder consultations, it had initially proposed to develop non-recallable and opportunity import rates. However, non-recallable and opportunity distinctions do not exist for the AESO’s domestic supply service. There likewise appeared to be no basis upon which to differentiate between non-recallable and opportunity import rates. Rate IOS recovers only the cost of losses and a transaction fee.

The AESO therefore proposed to continue the IOS rate as previously approved by the Board.

No party expressed any concern with respect to this rate. The Board finds the AESO proposal to be reasonable and it is approved as filed.

### 7.3 Merchant Service Rates

In the Application, the AESO noted that although it had initially proposed to develop rates for export and import service over merchant transmission lines using a point-to-point (rather than a network) service model, it ultimately decided to base its proposed rates for merchant services on a network service model. The proposed merchant service rates (Rates MTS, MOS 1 Hour, MOS 1 Month) would apply to customers exporting electric energy from the AIES over an intertie other than the Alberta-British Columbia and Alberta-Saskatchewan interties.

The proposed merchant service rates are similar in structure to the proposed DTS rate. However, the AESO noted that while the proposed XTS rates included a contribution to the costs of the

---

296 Ex. 242, TCE Evidence, Figure 4, p. 36
297 Ex. 242, TCE Evidence, Figure 4, p. 36
298 Application, Schedule 5.1, Black Start only $2.8 million of $644.9 million revenue requirement allocated to DTS
299 Ex. 005, Application, Section 4.9, p. 50
300 Ex. 008, Section 7 of the Application, pages 18, 20 and 22 of 129
Alberta-British Columbia and Alberta-Saskatchewan interties, these facilities would not be used for energy transfers over a merchant line. Accordingly, the AESO proposed to exclude both the fixed and variable wires costs attributable to the existing interties from rates applicable to service over the AIES for export using merchant interties. The AESO noted that it had not proposed to recover intertie costs through its proposed Rate IOS, and that Rate IOS would apply to imports over merchant transmission facilities without modification.

A description of the AESO’s conversion of fixed and variable intertie cost components into $/MWh amounts in Application Figure 4.9.1. A summary of the AESO’s derivation of its proposed merchant service rate schedules was provided in Application Schedule 5.8. Minor revisions to the AESO’s proposed merchant rate schedules as initially set out in section 7 of the Application were subsequently set forth in an AESO errata filing.

While the submissions of interveners did not generally focus on merchant service rates, the Board recognizes that many arguments provided in respect of XTS and XOS rates are also applicable to the design of merchant transmission service rates. Accordingly, the Board has taken parties’ views regarding other export and import service rates into account when considering its findings in respect of merchant service rates, as applicable.

The Board deals with the proposed MTS and MOS rates in separate sections below.

7.3.1.1 Merchant Transmission Service (Rate MTS)

The Board notes that the MATL project will not be completed within the anticipated effective period of the AESO’s 2007 tariff. As a result, the Board considers that the primary value in considering the proposed merchant transmission service rates in this Decision would be to provide an indication to future potential users of the prospective MATL intertie as to how they would be charged for using the Alberta transmission system to access the prospective MATL line.

As previously discussed in section 7.1.1 of this Decision, by virtue of subsection 27(1) of the 2007 Transmission Regulation, the remainder of section 27 applies to upgrades or enhancements resulting in increases to the path ratings of existing interties as well as to new interties proposed to be constructed. Subsection 1(1)(d) of the 2007 Transmission Regulation defines an intertie to mean “a transmission facility, including its associated components, that links one or more electric systems outside Alberta to the interconnected electric system.” Neither subsection 27(1) nor subsection 1(1)(d) differentiates between new interties proposed by the AESO and merchant interties. Accordingly, the Board’s findings regarding section 27 of the 2007 Transmission Regulation discussed in section 7.1.1 of this Decision are also generally applicable to the evaluation of the AESO’s proposed merchant transmission service rates.

In section 7.1.1, the Board found that a key principle arising from subsections 27(4) and 27(6) of the 2007 Transmission Regulation is that the costs arising from an intertie project are to be borne by the person proposing the intertie and should be shared with other persons only if, and to the extent that they directly benefit, section 27(4)(b) is otherwise satisfied. There is no guarantee that any merchant rate that may be approved in the future will approximate rate MTS as proposed by

---

301 Ex. 006
302 Ex. 382, AESO Errata Filing no. 2 dated May 10, 2007
the AESO in the Application, particularly if it is found that the incremental costs of providing the service are greater than the costs reflected in the proposed rate MTS.

During cross-examination by Board counsel, Mr. Martin on behalf of the AESO indicated that the AESO did not expect to invoice the developers of the MATL project for system impacts beyond the physical interconnection facilities for the MATL project itself. An exchange also took place between Board counsel and Mr. Martin regarding the AESO’s proposed treatment of potential incremental “deep system” costs that might be necessary to provide firm service to customers wishing to use the MATL intertie. If additional firm service MTS customers signed on to use the MATL intertie and the AESO determined that some incremental firm load from those additional customers resulted in a need for expenditures on additional facilities on the AIES, the AESO was asked if in those circumstances it intended to pass along those costs to either MATL or the MTS customers. The response was no, that additional facilities on the AIES that are deep-system facilities are shared by many customers. The AESO anticipated treating them in the same way as it does any other firm service, such that those costs would be shared by all users on the system and recovered through the rate itself as opposed to as an upfront contribution.

This exchange revealed that the AESO considers that it has discretion to assess incremental system costs against an individual customer contracting for firm merchant transmission service. However, the it expects that incremental system costs caused by providing a level of firm service to or from the MATL intertie would generally be shared by all users on the system and recovered through the DTS rate rather than through an upfront contribution to be paid by the merchant intertie developer or from users of the intertie through the inclusion of incremental deep system costs within rate MTS.

Noting the AESO’s intention that an approval of the proposed MTS rate should serve as an indication of what a potential MTS customer would expect to pay, the Board is concerned that an approval of the proposed MTS rate in light of the exchange referred to above could be misunderstood by potential MTS customers. In particular, consistent with the Board’s findings on proposed rate XTS, the Board considers that to the extent that incremental costs (including incremental deep system costs) may be caused by providing service to customers seeking rate MTS service, section 27 of the 2007 Transmission Regulation specifically requires such costs to be allocated among the person proposing the intertie and the customers that fall within the meaning of section 27(4) (rather than shared with other load customers such as DTS customers). Presently, however, the incremental cost arising from system reinforcements necessary to provide firm service from or to MATL is unknown. As such, there is no basis to conclude that incremental deep system costs arising from actions taken by the AESO to reinforce the Alberta transmission system to accommodate transmission service from or to MATL would reasonably correspond to any future merchant rate that may be proposed.

---

303 Tr. Vol. 3, p. 722, lines 11-20
304 Tr. Vol. 3, p. 725, lines 6-25, p. 726, and p. 727, lines 1-8
305 The observation that the incremental costs of firm service is unknown follows from the AESO’s latest 10 year transmission plan, which was filed as Ex. 107 as an attachment to the response to EnCana.AESO-004(a). On p. 56 of that document, the AESO notes that as long as intertie transactions are for opportunity services, it does not plan and reinforce the transmission system to provide a higher level of service. In addition, the AESO indicated that is not obligated to reinforce the transmission system for potential firm transfers in the absence of the users of the merchant facilities or the merchant developers contracting for firm service.
Another potential concern that the Board has with the proposed MTS rate, based on the exchange referred to above between Board counsel and Mr. Martin, is the potential that MTS contracts will be used by the AESO as a signal or catalyst for transmission system planning and reinforcement. While the following exchange between counsel for Powerex and the AESO panel occurred in the context of the proposed XTS rate, the Board is concerned that these comments also reflect the AESO’s approach to contract sign-ups for proposed rate MTS.

Q And is it correct to think that for transmission capacity planning purposes as you look out in the future that if the AESO enters into firm XTS contracts, then the capacity in respect of those contracts -- let's stay with the 200 megawatts for discussion purposes -- will be included in the transmission planning analyses so that you will be in a position to say, Yes, we build and plan our transmission capacity for the purpose of meeting firm export loads?

A MR. MARTIN: Yes, that would be the intent.

And I understand that was also part of the reason stakeholders wanted a firm rate proposed, so that they could start providing, I'll call it, real feedback to the AESO that there was a need for firm capacity that we would then build for.  

To the extent that this passage applies to merchant transmission service, it suggests that if a customer contracts for 200 MW of MTS service, the AESO would then begin to include an additional 200 MW above forecasted domestic load in load forecasts used for system planning purposes. Thus, if incremental system costs were to be generated by the consideration of the additional 200 MW of capacity, the Board understands that the incremental deep system costs would be borne by DTS customers.

The Board considers that using XTS or MTS contracts as a signal or catalyst for system planning purposes is not desirable for at least two reasons.

Firstly, noting that the minimum term for Rate MTS is 1 year (as distinct from the five year minimum term for Rate DTS), the Board is concerned that a customer seeking MTS service from or to a merchant intertie could induce additional system capacity to be created, simply by contracting for rate MTS. During cross-examination by Board counsel, both the AESO panel and the TCE panel were asked about the amounts that would be payable to the AESO by customers contracting for service under rate MTS. From these discussions, the Board is concerned that to the extent the AESO initiates the planning and development of additional capacity from or to a merchant intertie on the basis of the capacity of rate MTS contracts, the maximum cost incurred by an AESO customer as a result of entering into a rate MTS contract for a 1 year term could be considerably less than the costs of system reinforcements necessary to assure an essentially firm level of service.

---

307 Tr. Vol. 3 p. 723 lines 10-25 and p. 724
308 Tr. Vol. 6, p. 1198 lines 10-25 to p. 1204 lines 1-6
309 TCE indicated in discussions with Board counsel (Tr. Vol. 6, p. 1203) that assuming ATC availability in all hours, the annual cost of a Rate MTS contract would be $3.405 million. This estimated cost declined in direct proportion to reductions in percentage of hours that ATC was expected to be available in a given year.
Secondly, given that additional system costs incurred to accommodate service over a merchant intertie fall within section 27 of the 2007 Transmission Regulation, the Board finds that insufficient evidence was offered in this proceeding to allow the Board to determine whether the proposed MTS rate is in compliance with section 27. Accordingly, the Board is unable to approve this rate at this time.

The Board acknowledges that the TCE witness panel questioned the likelihood of customers entering contracts to induce additional firm capacity to or from an intertie since before an intertie is built, the benefits of firm import or export transactions cannot be used to offset the substantial cost of contracting for firm MTS service. However, the Board is concerned that the potential for customers to contract for firm MTS service to induce or advance additional deep system capacity may nevertheless exist. This potential is of sufficient concern that the Board is not prepared to approve the rate MTS at this time.

7.3.1.2 Merchant Opportunity Service Rates (MOS 1 Hour and MOS 1 Month)

The AESO proposed that its MOS 1 Hour and MOS 1 Month rates would generally reflect the cost allocation principles used by the AESO to develop its proposed XOS 1 Hour and XOS 1 Month rates. The main exception was that the AESO proposed that its MOS rates should not include an allocation of costs related to the existing interties, since the existing intertie facilities would not be used by exporters using a merchant line to access other markets.

For energy either generated or consumed in Alberta, the Board agrees that customers using a newly constructed merchant intertie would not require the use of the existing Alberta-British Columbia or Alberta-Saskatchewan interties. This indicates that the minimum charge component of the rate (based on the incremental variable cost associated with providing the service) would be equal to or lower than the corresponding XOS rate minimum charge. However, the Board finds that no evidence indicated that the value of the proposed merchant opportunity service (MOS) is less than the value of export opportunity service (XOS). Accordingly, the Board finds that the value of service based rate for MOS 1 Hour and MOS 1 Month is $3.98/MWh and $4.36/MWh respectively, consistent with the Boards findings in section 7.2.1.

8 TERMS AND CONDITIONS OF SERVICE

8.1 Customer Contribution Policy

8.1.1 Interconnection Project Cost Function

In Decision 2005-096, the AESO was directed to undertake further research to devise a more comprehensive investment function proposal which avoids the concerns expressed by the Board in that decision and which reflects the design principles described by the Board in that Decision. A proposal based on this research was to be presented in the AESO’s 2008 GTA.

In the Application, the AESO noted that following extensive debate during the 2005/2006 GTA, the Board in Decision 2005-096 amended the maximum local investment formula to provide a

---

310 Tr. Vol. 6, pp. 1209-1210
311 Ex. 005, Section 4 of the Application, p. 50 of 53, lines 13- 19
312 Decision 2005-96, pp. 57-58 (Direction 13A)
The Board notes that the largest single element in the proposed FDS rate is the allocation of TMR costs. The Board agrees with BCH that the AESO has not provided a sufficient basis for this charge. In particular, the Board does not consider that there is sufficient evidence that the AESO has considered the real value of Fort Nelson generation to Alberta customers.

The Board also notes the proposed $455,000 charge for contribution to fixed costs. The Board does not consider this charge has been justified on the basis of a reasonable allocation of actual costs.

The Board has determined that the following should form the basis for charges to BCH for Fort Nelson services. DTS service charges should include the following:

1. the postage stamp rate for bulk wires costs;
2. the greater of the postage stamp rate for local wires costs or the actual cost of the AE line providing service to Fort Nelson;
3. the postage stamp rate for the AESO’s own costs and other industry costs; and
4. the postage stamp rates for each of operating reserve charges, voltage control (TMR) and other system support charges.

The Board does not consider it necessary to charge a POD related cost as BCH provides its own facilities. Correspondingly, BCH should not be eligible for the PSC credit in the future as it will not be charged for POD services.

The STS service provided to Fort Nelson should continue to be charged at the full postage stamp rate plus a losses charge to be determined by the AESO, in the same manner as it would for an Alberta generator.

Both DTS and STS services provided to Fort Nelson should continue to be subject to the usual deferral account treatment, similar to that of any other customer.

The Board considers the above will result in just and reasonable charges for service to Fort Nelson. The Board also considers that this provides a reasonable template for the provision of other inter-provincial services as well. The AESO’s proposed tariff treatment of Fort Nelson is denied and the AESO is directed to continue to provide DTS and STS services to Fort Nelson on the basis set out above and the refiling should demonstrate this treatment.

5.8 Export Rates

5.8.1 Firm Export/Import Rates

In Decision 2002-099, the Transmission Administrator’s (TA) Congestion Management Decision, the Board directed the TA to “…further investigate whether a firm import/export service could be offered over the existing B.C. Tie with a level of “firmness” acceptable to prospective import/export customers”.

In response to this directive, the AESO submitted that it began contacting its customers active in importing and exporting in the spring and summer of 2004. On September 23, 2004, the AESO published an Alberta Import/Export Tariff discussion paper to broaden consultation with stakeholders. The paper was presented at a stakeholder conference on October 6, 2004 followed by written comments from six stakeholders. Discussion was also held at a December 3, 2004
stakeholder workshop, with a follow-up *Directions and Plans* discussion paper published on December 9, 2004.

The AESO submitted that the key considerations resulting from this examination of firm export and import services were:

- Firm export tariffs would add a new option for participants and may enhance investment opportunities for new supplies. However, at present there appears to be little demand for a firm export option and deferral of further detailed development until after the Wholesale Market Review appears appropriate.
- Deferring development of a firm export tariff will also allow careful examination of issues such that the introduction avoids or minimizes negative impacts on the market.
- Firm import tariffs appear inconsistent with the transmission cost allocation principles in the Transmission Regulation and would disadvantage imports compared to domestic supplies.

As a result of these considerations, the AESO proposed the following in its Application:

(a) Continued development of a firm export tariff with the objective of including such a tariff in the AESO’s 2007 General Tariff Application (expected to be filed in late 2005 or early 2006); and,

(b) No further action to be taken on establishing a firm import tariff at this time.

During the proceeding, a number of parties took the position that the AESO was not responding to the Board’s directives from Decision 2002-099 in a timely fashion, and requested that the Board order the AESO to implement firm import/export rates as part of its Decision in this proceeding. The parties further considered that the AESO was ignoring directives from the Transmission Regulation to implement firm import and export rates.

TCE presented and testified to evidence in the proceeding concerning a form of firm export service which it submitted that the AESO could implement in a timely fashion. By way of argument, the AESO submitted that TCE’s proposal provided for a different level of firm service than was normally accepted as firm in the utility industry. The AESO further noted that TCE agreed as well under cross examination that its proposal might be considered as a lower level of firm service.

The AESO further noted that TCE’s proposal for a deferral account mechanism in support of its proposed firm export service was lacking in detail, and thus TCE’s proposal should be set aside until a full stakeholder process could occur on this proposal.

Finally the AESO submitted that the position taken by a number of parties in the proceedings that the AESO was not responding to the urging of industry to develop firm import and export rates had taken it by surprise. The AESO further noted that both IPSAA and ATCO Power had failed to provide comments on its Import/Export discussion paper when given the opportunity. The AESO did submit in argument that, if further stakeholder consultation did identify the urgency suggested by parties in this proceeding, it would proceed to develop a new proposal for import and export tariffs prior to or in conjunction with its 2007 application.

---

55 See Argument in Chief and Reply Argument of TCE, IPSSA, TAU, ATCO Power.

56 T1919
TCE also took issue with the AESO’s calculation of Available Transfer Capacity (ATC). TCE suggested that the AESO should include all of the Calgary area generation in its calculations. The AESO responded that, while the export market required hourly commitments, the Alberta market required generator response on a minute by minute basis, and suggested that the reliability of the Alberta system could be jeopardized by deeming this generation to be available. The AESO further submitted, by way of exhibit\(^57\), that export ATC was to be governed as an AESO rule, per Subsection 20(1) of the EUA, and therefore was not subject to Board ruling.

FIRM submitted that WECC definitions of ATC unique to import and export services should be considered in the Alberta market calculation of ATC. FIRM further submitted that the application of a firm DTS rate to export without proper ratchet provisions and investment levels could result in preferential treatment inadvertently being part of an export tariff. FIRM supported the AESO position for further stakeholder consultation in the development of firm import and export tariffs, as well as agreeing with the AESO that its calculation of ATC not include all Calgary area generation.

IPCAA submitted that all TFO customers end up paying for TMR costs related to firm export tariffs, and as such, DTS customers would not be kept whole if a firm export tariff were developed. IPCAA further submitted that TCE had not established sufficient urgency that further stakeholder consultation on firm export service should be ignored. IPCAA noted\(^58\) TCE’s acknowledgement that not all stakeholders who will be impacted by the development of firm export tariffs had been contacted, and further noted\(^59\) TCE’s admission that its firm export tariff proposals were still maturing. IPCAA further considered that the Board should direct the AESO to consult with stakeholders prior to the end of 2005 concerning any changes to the definition of ATC in Southern Alberta.

The Board considers that the Transmission Regulation supercedes many of the principles it established in Decision 2002-099. As such, it is not clear to the Board that certain directives concerning import and export rates from that Decision can be still be considered to be in effect. The Board notes that even TCE acknowledged during cross\(^60\) that a number of principles from Decision 2002-099 would have to be modified because of the Transmission Regulation, including, for example, changes caused by the shifting of cost recovery from a 50/50 DTS/STS recovery to a 100% recovery from DTS customers.

The Board has reviewed Subsection 8(1)(g) of the Transmission Regulation, dealing with the restoration of the inter-tie to its rated capacity. The Board considers that the AESO has an obligation pursuant to the Transmission Regulation to make rules and to take measures to expand or enhance the transmission system in order to restore the path rating of the interconnections however, the regulation does not impose a time frame nor does it dictate the method in which this must be achieved. This provision is not a required matter to be included in the tariff under the regulation. Rather, it is part of the rule making authority conferred on the AESO. The Board therefore does not consider that the AESO is in breach of this section of the regulation should it choose not to pursue the development of import and export tariffs to the extent desired by parties in this proceeding. The Board notes, with encouragement, the fact that the AESO has invited significant stakeholder consultation in this process, as shown by the evidence in this proceeding.

\(^{57}\) Exhibit 30(13)
\(^{58}\) Page 28, IPCAA Argument in Chief
\(^{59}\) Page 29, IPCAA Argument in Chief
\(^{60}\) T1983, lines 14-20.
The Board further considers that TCE’s proposal for firm import and export rates is deficient at this point in time in that the Board considers there to be a potential for cross subsidization to occur due to the lack of detail currently available concerning TCE’s proposal for a TMR deferral account mechanism.

Therefore the Board will not require the AESO to include firm import or export rates as part of its 2006 tariff. The Board however, does encourage the AESO to continue the stakeholder discussions with interested parties on a go forward basis towards the potential development of firm import and export rates.

With respect to the calculation of ATC, the Board is in agreement with the AESO that this calculation does not fall under the Board’s jurisdiction, but is, instead, subject to AESO rules. The Board will therefore not provide any ruling concerning the AESO’s calculation of ATC, but again urges further consultation with stakeholders.

5.8.2 Generator Remedial Action Scheme (GRAS)

The AESO noted in its application that a GRAS is used to restore and maintain power system frequency at acceptable levels.

The AESO noted that it was approached by a group of stakeholders interested in increasing export capability during the fourth quarter of 2004. The AESO further noted that as part of these discussions, it and the stakeholder group had evaluated operating practices that might enable additional export opportunities consistent with the requirements of the Transmission Regulation.

The AESO noted that one potential action given prominent consideration in its discussions with the stakeholders interested in export capacity expansion was a proposal to re-establish a GRAS similar to the Keephills Remedial Action Scheme that was in place prior to 2000. The AESO submitted that a feasibility analysis of GRAS is currently underway and that the use of GRAS to increase export capability would be explored when this feasibility analysis was complete.

ATCO Power submitted that the AESO has an obligation to pursue measures such as GRAS in order to enhance export capability. ATCO Power submitted that the AESO should not be permitted to "kink the hose" by withholding export tariffs and export capacity, thereby stranding surplus generation in Alberta. Further, ATCO Power noted that Subsection 8(1)(g) of the Transmission Regulation requires the AESO to make arrangements for the expansion or enhancement of the transmission system so that, under normal operating conditions, the transmission system interconnections with jurisdictions outside of Alberta can import and export electricity on a continuous basis, at or near the transmission facility's path rating.

IPPSA also suggested that a GRAS was required in order to reflect true market conditions. IPPSA submitted that the AESO had GRAS capability at the Keephills PPA, and that GRAS equipment could be installed in a matter of months. As such, IPPSA recommended that the Board should direct the AESO to implement a GRAS as soon as it had completed its technical studies. TCE also submitted that the Keephills GRAS capability should be restored as soon as possible. In its evidence, TCE noted that the Alberta Government Transmission Development Policy paper indicated that the cost of RAS arrangements required to allow the interties to function as designed should be allocated to load.61

---

61 TCE Evidence (Exhibit 23-010) page 12 of 42, Citing Alberta Government Transmission Development Policy Paper (Exhibit 30-027), page 9
FIRM noted that as GRAS is associated with exports rather than imports, the costs of GRAS should be recovered completely from firm export loads as well as export opportunity loads to the extent that such loads are responsible for GRAS costs.

The Board agrees with parties that GRAS may be pursued by the AESO as part of its strategy to ensure that interconnections with jurisdictions outside Alberta can import and export electricity on a continuous basis at or near the path rating of the interconnections. The Board does not agree, however, that Subsection 8(1)(g) of the Transmission Regulation may be interpreted in a manner that should cause the Board to direct the AESO to re-implement a generator remedial action scheme. The Board considers that direction to the AESO in the Transmission Regulation to restore the capacity of the intertie does not supersede the AESO’s duty to ensure a safe, reliable system. As such, the Board considers that the AESO must be satisfied that system safety and reliability is not compromised by a decision to implement a program such as GRAS. The Board is comforted by the ongoing efforts of the AESO to ensure that GRAS may be implemented reliably before any steps are taken to implement it.

In any event, the Board is reluctant within the context of a tariff application proceeding to, in effect, over-ride the AESO’s technical judgement on the measures that the AESO needs to take to fulfill its mandate to ensure the reliable operation of the transmission system. In this regard, the Board expects that the implementation of GRAS would generally be affected through the development of an operating policy and, as such, would fall under the ambit of an AESO rule pursuant to Section 20 of the EUA. Accordingly, the Board notes that concerns about the appropriateness of an AESO operating policy should generally be brought before the Board through the complaint mechanism described in Section 25 of the EUA.

In light of the foregoing, therefore, the Board will not direct the AESO to implement a GRAS as part of this Decision. However, the Board does agree with TCE that the Transmission Development Policy clearly indicates that the costs of internal reinforcements and RAS arrangements necessary to allow the interties to operate at their design capacity are to be allocated to load, irrespective of whether the RAS arrangement is export or import related.

Accordingly, if the AESO were to enter into a RAS arrangement during the term of the Tariff, the Board would expect that the costs of this arrangement would be allocated to DTS customers. The Board may consider other cost allocation arrangements only after the rated design capability of the existing intertie facilities has been restored.

5.8.3 Opportunity Import and Export Rates

The Board notes that the AESO has proposed minor changes to its opportunity import and export rates to accommodate the provisions of the Transmission Regulation that requires DTS customers to pay for 100% of load.

The Board notes that no parties commented against the AESO’s proposed modification to these two rates. The Board has reviewed the proposed modifications and considers them to be in compliance with the changes required by the Transmission Regulation as noted above and therefore approves the AESO’s proposed modifications to these rates. The Board directs the AESO to update its proposals accordingly in its refiling, using the values which result from the Board’s recommended rate design, as discussed in section 5.5 of this Decision.
Fortis also disputed AltaLink’s assertion that the AESO did not object to AltaLink’s proposal, noting the following comments of Mr. Millar:113

The entire structure of contributions in aid of construction is really set up, first and foremost, to ensure overall proper cost accountability among the customers. And from the AESO’s perspective, a distribution company is another customer, and we would expect the same tariff provisions to apply and, in fact, are required by this Board to treat a distribution point of delivery the same as an industrial point of delivery for investment and contribution purposes.

So we see that as being the primary issue. Distribution companies generally have fairly large held contributions in aid of construction that are reducing their net rate base. The fact that they may be obliged to pay a contribution that increases the rate base I don’t think is necessarily a conceptual problem we have.

The contribution then may go on to reduce the transmission facility owner’s net rate base. They obviously still own the asset, and it’s sitting in the transmission facility owner’s fixed capital records, but the calculation of net base rate would be reduced.

And if that is causing some perceived loss to the transmission facility owner, I think there are other ways of addressing that issue, and that should be an issue the transmission facility owner should bring before the Board in their own rate application.

I don’t think it would be appropriate to adjust the contribution policy to achieve, I’ll say, a bad outcome on the signal it’s sending customers for the sake of addressing the issue in the transmission facility owner’s, in their books, and that it issue -- if to the extent it is an issue -- can properly and probably be better addressed head on than by trying to ensure that contributions aren’t paid in the first place.

The Board has considered the comments of AltaLink and finds that the AltaLink proposal would create unnecessary changes to current practice and administrative complexity, largely to effect an increase in TFO rate base. The AltaLink proposal is denied.

7.4  Merchant Transmission Interconnections

This issue was first raised by TCE in its intervener evidence. TCE noted that Section 15(6) of the Transmission Regulation stated:

The ISO must include in the ISO tariff, rates and terms and conditions that include costs for use of the interconnected electric system, appropriate for the class of service provided to persons who use the facilities referred to in this section for import or export of electricity to or from Alberta.

TCE maintained the Application does not provide the rates and T&Cs contemplated by Section 15(6). These rates and terms and conditions were needed by transmission developers, including merchant transmission developers, to determine the cost of service for use of an interconnection with the AIES.114

TCE recommended the following principles in respect of transmission facilities seeking to export or import electricity:

---

113 Transcript Volume 1, pages 184-186
114 TCE.AEso-229(c)
1. An interconnection tariff will only be based on the use of that portion of the AIES that is reasonably attributed to the merchant transmission line (i.e. on a point to point basis).

2. An interconnection tariff respecting the use of the AIES will be based on the AIES transmission lines actually used to provide the service. Such a tariff will not be based on theoretical transmission lines that could be built to provide a direct connection to the merchant transmission line from the generators supplying energy over the lines.

3. Costs of the transmission facilities involved in providing service to the merchant transmission line, including facility specific losses, will be shared with other users of the same facilities based on a pro rata sharing of those lines using peak loads for each user.

4. Costs recovered from merchant transmission developers will be based on the actual cost of service of the transmission facilities being shared by other AIES Customers using the same transmission facilities.

5. All costs of a transmission line built solely to interconnect a generator with the merchant transmission line, and that provides no benefit to the AIES, would be charged to the merchant transmission developer.

In argument, the AESO stated that, other than that provided by TCE, there was limited evidence or discussion on merchant transmission issues or principles. The issue of tariffs for merchant transactions was closely linked to tariffs for exports and imports over existing interconnections. The AESO stated a broad consultation with stakeholders on the combined issues had not occurred.

The AESO supported the continued examination of merchant transmission interconnection issues, such as those raised by TCE, through consultation. The AESO further requested that the Board refrain from taking a view on principles at this time. The AESO believed that principles, tariffs, and terms and conditions could be provided as part of the AESO 2007 GTA.

In reply, TCE maintained that the AESO had not complied with Subsection 31(1) of the Transmission Regulation which required the tariff to include all matters required by the regulation and included those provisions contemplated in Subsection 15(6). TCE submitted that, if the Board agreed with TCE’s interpretation of these sections in the Transmission Regulation, then the Board should not accept the proposal that the principles, tariffs, and terms and conditions be delayed until the AESO 2007 GTA. The more compliant approach would be to adopt or modify TCE’s recommended principles\textsuperscript{115} and then direct the AESO to prepare a set of tariffs, terms and conditions that reflect those principles as soon as reasonably practical.

The Board has considered the provisions referenced and, while it agrees with TCE that the AESO proposed tariff must contain provisions that include costs for use of the interconnected electric system for import or export, the Board finds that this provision does not require the development of tariff rate terms and conditions for merchant use.

As the proposed tariff includes provisions for the use of the AEIS for import and export services, the Board considers the provision in Subsection 15(6) to be satisfied. The Board appreciates the

\textsuperscript{115} Exhibit 23-010, TransCanada Written Direct Evidence, page 29, line 20 to page 30, line 11
concern of TCE but notes the evidence of the AESO that TCE is the only party to comment to any extent on this matter and that broad consultation with stakeholders had not occurred yet.

The Board is prepared to grant the request of the AESO that no further action be taken on principles as a result of this proceeding. However, the Board directs the AESO to consult with stakeholders in the interim and address merchant interconnection principles in the 2007 GTA.

7.5 Contract Term, Reductions, and Termination

In the Application, the AESO explained that Article 14 had been expanded to include the provision that, in reducing contract capacity, the customer will be required to sign a revised System Access Service Agreement and may be required to pay a customer contribution. The potential for an additional contribution recognizes that the proposed local investment is based on a specific contract capacity over a contract term. The maximum local investment would therefore be reduced, in proportion to a reduction in contract capacity, to a level potentially below the customer-related costs and therefore require a customer contribution. A reduction or termination notice period of 5 years was proposed as part of the revised article.

Article 14.3 has been added to provide to customers who request early contract termination the option of making a lump sum payment to the AESO, as an alternative to ongoing monthly billing.

Alpac noted that the AESO had provided three reasons for requiring a 5 year notice:

1. Transmission planning (the primary reason);
2. Contribution policy provisions; and,
3. Tariff design and system cost recovery.

Alpac took issue with all three reasons cited by the AESO in support of their proposal. Alpac acknowledged the AESO’s responsibilities under the Transmission Regulation to forecast load but questioned what effect a reduction in load of 10 MW would have when AESO was forecasting 250 MW of load growth per year over the next ten years. During cross-examination Alpac asked the AESO to consider the addition or loss of a 10 MW POD, which is about the average size in Alberta. The AESO advised changes would need to be “…tens of megawatts before there's material impact in an area.”

Alpac noted that the five year notice provision may be justified under the current contribution policy where TFO investment in customer-related costs is partially made under the “roll-in ceiling”. The premise is that an amount of investment, up to $6 million, can be made without a corresponding level of revenue certainty. Under the proposed “revenue based” contribution policy, DTS revenue, via the DTS Contract Capacity, will always be proportional to the amount of TFO investment in customer-related facilities. Under the AESO’s proposed 2006 contribution

---

116 Section 6, page 39
117 T. 105/5-19
118 T. 105/11-14
119 T. 142/17 – 143/11
120 Exhibit 02-029-003 A - Attachment IPCAA-AESO-025 A (Attachment to IPCAA-AESO-025(a)(b)) (Feb 25, 05), Median POD Contract Capacity size is 11.5 MW
121 T. 115/15-19 & T. 144/15-23
122 Exhibit 030-004