February 6, 2011

Wayne MacKenzie
Application Officer
Alberta Utilities Commission
Utilities Division, Calgary Office
Fifth Avenue Place
400, 425 – 1st Street SW
Calgary, Alberta  T2P 3L8

Dear Wayne:

Re:  **AESO 2010 ISO Tariff Compliance Filing Pursuant to Decision 2010-606**

1 Attached please find the AESO’s refiling of its 2010 ISO tariff to reflect the findings, conclusions, and directions in Decision 2010-606 of the Alberta Utilities Commission (Commission). The compliance filing addresses all matters to be included in the refiling, including rates and terms and conditions of service. Compliance with the specific directions in Decision 2010-606 is discussed in section 2 of the application.

2 In addition, in accordance with the Commission’s approval in its letter of January 26, 2011, the AESO has incorporated into the compliance filing the annual tariff update for 2011. The 2011 tariff update is discussed in section 3 of the application.

3 The AESO notes that the application refers to Appendices H and I which contain blackline versions of the refiled tariff and the refiled tariff definitions, respectively. Those appendices are not yet available, and will be filed as soon as possible when complete.

4 This application is a straightforward compliance filing in respect of directions in Decision 2010-606, as well as a tariff update in accordance with the methodology for such updates approved in Decision 2010-606. As such, the AESO suggests the application be dealt with through a written proceeding.

5 The AESO has requested that the 2011 tariff be approved to be effective April 1, 2011, with 2010 versions of section 8 and 9 of the tariff approved to be effective January 1, 2010 to March 31, 2011. In the event the tariff cannot be approved to be effective on those dates, the AESO would appreciate being advised of the likely effective date as soon as practical to allow it to adjust its implementation plans accordingly.
Please direct all correspondence relating to this application to:

John Martin  Raj Sharma  Morag MacLachlan  
Director, Tariff Applications  Senior Tariff Analyst  Manager, Regulatory Support Services
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Calgary, Alberta T2P 0L4  Calgary, Alberta T2P 0L4  Calgary, Alberta T2P 0L4
Phone: 403-539-2465  Phone: 403-539-2632  Phone: 403-539-918
Fax: 403-539-2524  Fax: 403-539-2524  Fax: 403-539-2524
Email: john.martin@aeso.ca  Email: raj.sharma@aeso.ca  Email: morag.maclachlan@aeso.ca

If you have any questions on this application or need additional information, please contact me at 403-539-2465 or by email to john.martin@aeso.ca.

Yours truly,

[original signed by]

John Martin  
Director, Tariff Applications

attachments

cc: Heidi Kirmaier, Vice-President, Regulatory, AESO  
   Raj Sharma, Senior Tariff Analyst, AESO
Alberta Electric System Operator
2010 ISO Tariff Compliance Filing
Pursuant to Decision 2010-606

Date: February 6, 2011
Prepared by: Alberta Electric System Operator
Prepared for: Alberta Utilities Commission
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C 2011 Escalation Factor and Investment Levels
D 2010 Refiled Sections 8 and 9
E 2011 Refiled Tariff
F Refiled Tariff Definitions
G AESO 2011 Updated Business Plan and Budget Proposal
H Blackline Version of 2011 Refiled Tariff
I Blackline Version of Refiled Tariff Definitions
1 Application

On December 22, 2010, the Alberta Utilities Commission (Commission) issued Decision 2010-606 with respect to the 2010 ISO Tariff Application (Application) of the Alberta Electric System Operator (AESO). The AESO had filed the Application with the Commission on March 5, 2010. The Application requested approval of the rates to be charged for, and the terms and conditions that apply to, each class of system access service provided by the AESO.

Decision 2010-606 provided various directions to the AESO with respect to the Application, and concluded on page 102 as follows:

IT IS HEREBY ORDERED THAT the AESO shall refile its 2010 General Tariff Application to reflect the findings, conclusions and directions in this Decision on or before February 1, 2011.

On January 31, 2011, the AESO requested a three-day extension to the filing deadline, which the Commission approved in its letter dated February 1, 2011.

This compliance filing is submitted in response to the order of the Commission in Decision 2010-606 as quoted above, and complies with all directions in that decision which were to be addressed in the refiling. The AESO notes that some directions in the decision are to be addressed in the AESO’s next comprehensive tariff application or in other future applications, and these accordingly are not addressed in this refiling.

On January 19, 2011, the AESO proposed to incorporate a 2011 tariff update as part of this compliance filing. The Commission approved the AESO’s proposal in its letter of January 26, 2011. The 2011 tariff update is discussed in more detail in section 4 of this application.

This compliance filing is organized into the following sections.

1 Application — Provides background on the application and specifies the relief requested.

2 Compliance With Decision 2010-606 — Summarizes the AESO’s compliance with Decision 2010-606 and provides response to each direction in that decision.

3 2011 Tariff Update — Discusses the 2011 revenue requirement, rates update, forecast billing determinants, bill impacts, and maximum investment level which comprise the 2011 ISO tariff update.

4 Implementation — Discusses the effective dates of the refiled tariff and the AESO’s plans for implementation.

This application also includes the following appendices:

- A 2010 Rate Calculations
- B 2011 Rate Calculations
- C 2011 Escalation Factor and Investment Levels
1.1 Relief Requested

Accordingly, in respect of:

- the AESO’s tariff and rates approved by the Commission pursuant to sections 30 and 119 of the Electric Utilities Act, and
- Commission Decision 2010-606 and orders and directions made thereto,

the AESO requests the following:

(a) confirmation that the Commission’s directions in Decision 2010-606 have been satisfactorily responded to, for those directions which require responses at this time;

(b) approval of the 2011 ISO tariff provided as Appendix E of this compliance filing, to be effective April 1, 2011, including rates, riders, terms and conditions, and appendices, all as refiled;

(c) approval of the definitions provided as Appendix F of this compliance filing, also to be effective April 1, 2011, as refiled;

(d) approval of the 2010 construction contribution provisions in section 8 and 9 of the ISO tariff provided as Appendix D of this compliance filing, to be effective from January 1, 2010 to March 31, 2011, as refiled; and

(e) such other relief as the Commission deems appropriate.

All of which is respectfully submitted this 6th day of February, 2011.

Alberta Electric System Operator

Per: _______________________________

Heidi Kirrmaier
Vice-President Regulatory
2 Compliance With Decision 2010-606

This refiling comprehensively addresses all matters in Decision 2010-606 which required responses at this time.

2.1 Compliance Matters Addressed

Responses to the directions to the AESO in Decision 2010-606 are discussed in sections 2.2 and 2.3 below. This compliance filing also includes other minor changes, as discussed below.

The 2010 forecast cost for wires has been updated to reflect more recent approvals of transmission facility owner tariffs for 2010. These changes have been highlighted in Table A2-2 in Appendix A of this application, and reflect the following:

(a) approval of ENMAX’s transmission facility owner tariffs in Commission Decision 2010-593, at amounts of $37.2 million for the 12 months ending June 30, 2010 and $39.1 million for the 12 months ending June 30, 2011, for an aggregate tariff of $38.1 million for the calendar year 2010;

(b) approval of the City of Lethbridge’s 2010 transmission facility owner tariff of $5.4 million in Commission Decision 2010-411;

(c) approval of the City of Red Deer’s 2010 transmission facility owner tariff of $2.1 million in Commission Decision 2010-352; and

(d) approval of FortisAlberta’s 2010 farm transmission costs of $4.1 million in Commission Decision 2010-560.

The refiled tariff provided in Appendix E of this compliance filing includes the 2011 Balancing Pool Consumer Allocation Rider F, as approved by the Commission in Decision 2010-564 released on December 7, 2010, to be effective January 1, 2011.

Certain definitions of terms used in the tariff have been updated for consistency with definitions that have become effective for use in ISO rules and Alberta reliability standards. The definition changes are minor in nature, do not affect the intent, interpretation, or applicability of those definitions, and are discussed in more detail in response to Direction 15.

Finally, typographical errors, formatting inconsistencies, and similar minor errors have been corrected in the refiled tariff provided in Appendix E of this compliance filing.

2.2 Summary of Directions

The following table provides a summary of the directions provided in Decision 2010-606 and indicates whether each direction has been responded to in this compliance filing or will be responded to in a future AESO tariff or other application.
<table>
<thead>
<tr>
<th>No</th>
<th>Direction</th>
<th>Sec</th>
<th>Page</th>
<th>This Refiling</th>
<th>Future Application</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Remove energy classification of isolated generation costs in Rate DTS</td>
<td>6.1.4</td>
<td>20</td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>Continue existing classification of bulk system costs</td>
<td>6.2.1</td>
<td>22</td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>File updated cost study and comprehensive tariff application by March 31, 2013</td>
<td>6.3.1</td>
<td>26</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>4</td>
<td>Provide forecast multi-year rate design in next tariff application</td>
<td>6.3.2</td>
<td>28</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>5</td>
<td>Use long-term plan, with adjustments, for &quot;prospective component&quot; of next cost study</td>
<td>6.3.2</td>
<td>28</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>6</td>
<td>Remove energy classification of isolated generation costs in Rate PSC</td>
<td>7</td>
<td>35</td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>7</td>
<td>Use 38.5 MW as baseline for Rate FTS future voltage control charge</td>
<td>8.6</td>
<td>49</td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>8</td>
<td>Delete Interim Refundable Fort Nelson Rider H</td>
<td>8.6</td>
<td>49</td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>9</td>
<td>Continue existing local system charge in Rate FTS</td>
<td>8.6</td>
<td>50</td>
<td></td>
<td>✓</td>
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<tr>
<td>10</td>
<td>Include termination charge for only original ATCO Electric line in Rate FTS at this time</td>
<td>8.6</td>
<td>51</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>11</td>
<td>Update Rate FTS to reflect directed changes</td>
<td>8.6</td>
<td>51</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>12</td>
<td>Continue to investigate firm export rates</td>
<td>9.2.2</td>
<td>52-53</td>
<td></td>
<td></td>
</tr>
<tr>
<td>13</td>
<td>Remove Rider I and related provisions</td>
<td>9.3.1</td>
<td>58</td>
<td></td>
<td>✓</td>
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<tr>
<td>14</td>
<td>Discuss proposed changes to Rider C in future tariff or other application</td>
<td>9.4.2</td>
<td>60</td>
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<td>✓</td>
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<tr>
<td>15</td>
<td>Apply for approval of material amendments or revisions affecting the tariff</td>
<td>10.1</td>
<td>62</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>16</td>
<td>Indicate AESO has final oversight of good electric industry practice</td>
<td>10.2.3</td>
<td>72</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>17</td>
<td>Clarify AESO responsibility for deeming facilities in excess of good electric industry practice</td>
<td>10.2.3</td>
<td>72</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>18</td>
<td>Revise operations and maintenance charge provision in section 8 of tariff</td>
<td>10.4.3</td>
<td>89-90</td>
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<td>✓</td>
</tr>
<tr>
<td>19</td>
<td>Report on impact and feasibility of waiving notice provisions for energy efficiency projects</td>
<td>10.5</td>
<td>92</td>
<td></td>
<td>✓</td>
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<tr>
<td>20</td>
<td>Provide the present value of investment for incremental changes to contract capacity</td>
<td>10.6.1</td>
<td>95</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>21</td>
<td>Address cost recovery for PSS or AVR additions to</td>
<td>10.6.2</td>
<td>96</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>No</td>
<td>Direction</td>
<td>Sec</td>
<td>Page</td>
<td>This Refiling</td>
<td>Future Application</td>
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<td>-------------------</td>
</tr>
<tr>
<td>22</td>
<td>Revert to current tariff description of system-related costs</td>
<td>10.6.3</td>
<td>96</td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>23</td>
<td>File next comprehensive tariff application no later than March 31, 2013</td>
<td>11.1</td>
<td>100</td>
<td></td>
<td>✓</td>
</tr>
</tbody>
</table>

### 2.3 Responses to Directions

The following pages provide additional detail on the AESO’s responses to the directions in Decision 2010-606.
Remove Energy Classification of Isolated Generation Costs in Rate DTS

**Direction**

The Commission found in section 6.1.2 of this Decision that the functionalization and classification of transmission wires costs should not incorporate the results of the Transmission O&M Cost Study. In light of this finding, it would be inconsistent to utilize a portion of the Transmission O&M Cost Study as the basis to change the classification of isolated generation costs to be on an energy basis. The AESO is directed to reflect this finding in its Refiling Application. [page 20, paragraph 89]

**Response**

Isolated generation costs have been classified on the same (proportional) basis as used to classify all other local system and point of delivery costs in the rate calculations for Rate DTS in Appendices A and B of this compliance filing. This has been accomplished by including isolated generation costs in the wires costs classified in Tables A5-3 and B5-3 for 2010 and 2011, respectively, without the adjustment originally proposed in the 2010 ISO tariff application.
2 Continue Existing Classification of Bulk System Costs

Direction

The Commission has concerns, which are discussed in detail in section 6.3.1 of this Decision, that the timetable proposed by the UCA for future cost studies is not logistically feasible. The Commission accordingly directs that the classification of bulk system costs remain unchanged for this tariff. The Commission anticipates this issue will be reviewed in the future. [page 22, paragraph 104]

Response

Bulk system costs are classified as 82.0% related to coincident demand ($/MW) and 18.0% related to flat usage ($/MWh) in Tables A5-3 and B5-3 for 2010 and 2011, respectively, in Appendices A and B of this compliance filing. This continues the classification used in the AESO’s current tariff.
3 File Updated Cost Study and Comprehensive Tariff Application by March 31, 2013

Direction

26 The Commission considers that the recommendation for an updated Transmission Cost Causation Study to be filed no later than July 1, 2011 is not reasonable. As discussed in section 11.1 of the Decision, the Commission has approved an AESO proposal to file comprehensive tariff applications every three years. In accordance with this approval, the Commission anticipates that the AESO’s next GTA will cover a test period commencing no earlier than 2014 and continuing in effect until 2016 or 2017. Given this anticipated timeframe, the Commission considers that the AESO’s next major cost causation study should reflect more meaningful TFO cost data that would be obtained as close as possible to the expected tariff term. The Commission has reviewed the process schedule prepared by the AESO as an undertaking to Commission counsel. The Commission finds that the process steps and timelines described therein can be undertaken in line with the AESO’s expected filing of its next GTA. The Commission directs the AESO to file an updated Transmission Cost Causation Study along with its next major tariff application, no later than March 31, 2013. [page 26, paragraph 128]

Response

27 The AESO will file its next comprehensive tariff application, including an updated transmission cost causation study, no later than March 31, 2013.
4 Provide Forecast Multi-Year Rate Design in Next Tariff Application

**Direction**

28 The Commission does not consider it sufficient for the AESO to provide a model to permit interested parties to evaluate potential rate impacts under various assumptions, without incorporating forecast capital additions into the cost causation study. Accordingly, the AESO is directed to provide a forecast of anticipated transmission system additions and take this forecast into account in the AESO functionalization, classification, and rate design for each test year of the expected term of the AESO’s GTA which the Commission has directed be filed no later than March 31, 2013. [page 28, paragraph 140]

**Response**

29 The AESO will provide a forecast of anticipated transmission system additions in its next comprehensive tariff application, and will take this forecast into account in the functionalization, classification, and rate design for each test year of the expected term of the tariff application.
5 Use Long-Term Plan, With Adjustments, for “Prospective Component” of Next Cost Study

**Direction**

30 The Commission acknowledges the AESO’s observation that forecasts of major transmission system additions may be subject to significant uncertainty with respect to the actual cost and timing of transmission capital projects. However, in consideration of the major impact that assumptions may have on the reasonableness of the AESO’s ultimate rate design, the Commission expects that the AESO will make its best effort to ensure that information related to the forecast capital build is as accurate as possible at the date of filing of the AESO’s next GTA. To this end, the Commission directs the AESO to utilize the most recent AESO long term transmission plan at the time of the AESO’s next major GTA as the baseline for the “prospective component” of the transmission cost causation study. However, to the extent that the AESO is aware of any significant differences as to the expected composition, cost, or timing of transmission system additions described in the most recent long term transmission plan, the AESO is directed to make required adjustments within the transmission cost causation study filed with the GTA. [page 28, paragraph 141]

**Response**

31 The AESO will utilize the most-recently published AESO long-term system plan, with adjustments to reflect expected significant differences from the plan as published, for the “prospective component” of the transmission cost causation study to be filed with its next comprehensive tariff application.
6 Remove Energy Classification of Isolated Generation Costs in Rate PSC

**Direction**
In section 6.1.4 of this Decision, the Commission directed the AESO to remove the effect of its proposed classification of isolated generation costs on an energy basis from its Rate DTS design. As this treatment of isolated generation costs has also been reflected in the AESO’s proposed PSC, the AESO is directed to adjust the PSC to remove the parallel treatment of isolated generation costs at the time of its Refiling Application. [page 35, paragraph 182]

**Response**
The energy classification of isolated generation costs has been removed from Rate PSC, in parallel with its removal from Rate DTS discussed in response to Direction 1 in this compliance filing.

Rate PSC, as included in the refiled tariff in Appendix E of this compliance filing, includes the following components calculated from the point of delivery charge in Rate DTS:

<table>
<thead>
<tr>
<th>Rate Component</th>
<th>Rate DTS Charge</th>
<th>PSC Factor</th>
<th>Rate PSC Credit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Substation fraction</td>
<td>$8,544.00/month</td>
<td>79%</td>
<td>$6,750.00/month</td>
</tr>
<tr>
<td>First (7.5 × substation fraction) MW of billing capacity</td>
<td>$5,788.00/MW</td>
<td>79%</td>
<td>$4,573.00/MW</td>
</tr>
<tr>
<td>Next (9.5 × substation fraction) MW of billing capacity</td>
<td>$2,136.00/MW</td>
<td>79%</td>
<td>$1,687.00/MW</td>
</tr>
<tr>
<td>Next (23 × substation fraction) MW of billing capacity</td>
<td>$1,294.00/MW</td>
<td>79%</td>
<td>$1,022.00/MW</td>
</tr>
<tr>
<td>All remaining MW of billing capacity</td>
<td>$709.00/MW</td>
<td>100%</td>
<td>$709.00/MW</td>
</tr>
</tbody>
</table>
Use 38.5 MW as Baseline for Rate FTS Future Voltage Control Charge

Direction

The Commission directs the AESO to revise subsection 5(3) of the voltage control charge in Rate FTS to reflect the following wording in its Refiling Application:

After completion of phase 1 of the northwest Alberta transmission development as approved in Approvals U2006-205, U2006-275, U2007-348, U2008-318 and others if applicable, the voltage control charge will also include the sum, over all hours in the settlement period in which Rainbow area load exceeds 145 MW and transmission must-run generation is required in the Rainbow area, of the cost associated with transmission must-run generation in the Rainbow area in an hour multiplied by the ratio in the hour of:

(a) Fort Nelson load in excess of 38.5 MW; to

(b) the sum of Fort Nelson load in excess of 38.5 MW and Alberta Rainbow area load (excluding Fort Nelson load) in excess of 106.5 MW.

Response

The directed wording has been used in subsection 5(3) of Rate FTS in the refiled tariff in Appendix E of this compliance filing.
8. **Delete Interim Refundable Fort Nelson Rider H**

**Direction**

The Commission finds that adopting the proposed change to how TMR costs are allocated under Rate FTS eliminates any future need for Rider H. The Commission directs the elimination of the interim refundable Fort Nelson Rider H and finds that there are no costs that need to be reviewed and reassessed for a final determination of costs under Rider H. [page 49, paragraph 255]

**Response**

Interim Refundable Fort Nelson Rider H has been deleted from the refiled tariff in Appendix E of this compliance filing.
9  Continue Existing Local System Charge in Rate FTS

**Direction**

The Commission directs the AESO to continue the existing local system charge and to revisit the charge either in its next GTA, or, if necessary, file a separate Rate FTS amendment application should BC Hydro’s requested service level, or the results of the coordinated planning effort between BC Hydro and the AESO, require a capital solution rather than a short-term TMR solution. [page 50, paragraph 260]

**Response**

The local system charge in Rate FTS in the AESO’s current tariff has been continued in subsection 3 of Rate FTS in the refiled tariff in Appendix E of this compliance filing.
10. Include Termination Charge for Only Original ATCO Electric Line in Rate FTS at This Time

**Direction**

41 The Commission directs the AESO to incorporate the proposed term 7(1)(a) as it relates to the levelized cost of the original ATCO Electric line providing service to Fort Nelson. The Commission recognizes that the proposed terms 7(1)(b) and (c) may no longer be required for this tariff given its direction with respect to the local system charge, but directs that a similar provision should be included for any levelized cost allocated to Fort Nelson for any future northwest Alberta transmission development. [page 51, paragraph 263]

**Response**

42 The AESO has incorporated only subsection 7(1)(a) of the originally-proposed Rate FTS in subsection 7(1) of Rate FTS in the refiled tariff in Appendix E of this compliance filing.
11 Update Rate FTS to Reflect Directed Changes

**Direction**
43 The Commission directs that the AESO’s Refiling should reflect an updated Fort Nelson Demand Transmission Service, Rate FTS that incorporates the changes directed by the Commission. [page 51, paragraph 264]

**Response**
44 An updated Fort Nelson Demand Transmission Service Rate FTS that incorporates the directed changes is included in the refiled tariff in Appendix E of this compliance filing.
12 Continue to Investigate Firm Export Rates

**Direction**

The Commission accepts that the AESO’s rationale for not proposing a firm service export within the current Application is reasonable. The Commission directs the AESO to continue to investigate firm export rates in consultation with stakeholders. In the event that transmission reinforcements pertinent to the export ATC are expected to be completed in advance of the GTA that the Commission expects to be filed on or before March 31, 2013, the AESO is directed to file a stand alone application for a proposed firm export rate on a timely basis. [pages 52-53, paragraph 276]

**Response**

The AESO continues to investigate firm export rates in consultation with stakeholders and will apply for approval of such a rate when it is developed. The AESO expects such application will be made before the AESO’s next comprehensive tariff application.
13 Remove Rider I and Related Provisions

**Direction**

In consideration of the above, the Commission makes no findings in respect of the merits of Rider I at this time. The AESO is directed to revise its proposed T&Cs to remove provisions related to Rider I in its Refiling. Rider I will be considered in association with the management fee in the upcoming 2011 Generic Cost of Capital proceeding (Proceeding ID. 833). [page 58, paragraph 302]

**Response**

The AESO has removed Amortized Construction Contribution Rider I, as well as references to Rider I in Demand Transmission Service Rate DTS, from the refiled tariff in Appendix E of this compliance filing.
14 Discuss Proposed Changes to Rider C in Future Tariff or Other Application

**Direction**

In consideration of the above, the Commission remains interested in understanding whether potential changes in the design of Rider C could contribute to a reduction in the frequency of tariff update applications and/or deferral account reconciliations. Accordingly, the Commission directs the AESO to discuss proposed changes to the design of Rider C no later than its next GTA unless already addressed in another context such as in relation to a future AESO deferral account reconciliation application. [page 60, paragraph 315]

**Response**

The AESO will discuss proposed changes to the design of Deferral Account Adjustment Rider C in either its next comprehensive tariff application or in another context such as a future AESO deferral account reconciliation application.
Apply for Approval of Material Amendments or Revisions Affecting the Tariff

Direction

Accordingly, the Commission directs the AESO to apply for approval of amendments which would materially change the tariff. Given this direction, Commission approves the AESO’s proposed reorganization of its T&Cs, subject to findings made in relation to specific provisions of the T&Cs below. [page 62, paragraph 332]

Response

The AESO will apply for approval of any proposed substantial amendments or revisions to definitions or other provisions of the terms and conditions in the event such proposed changes could materially change the tariff.

With respect to definitions, the AESO notes that some of the definitions originally proposed in its tariff application have since become effective for use in ISO rule and Alberta reliability standards, and contain minor differences in wording or structure from the definitions filed in the 2010 ISO Tariff Application. The AESO has provided updated tariff definitions in Appendix F of this compliance filing which incorporates those minor changes for the following terms:

- Act,
- affiliate,
- contract capacity,
- generating unit, and
- pool price.

As well, a new definition of “apparent power” became effective on July 23, 2010 for use in ISO rules and Alberta reliability standards, following a filing and notice process pursuant to subsection 20.2(1) of the Electric Utilities Act. The AESO accordingly has included the new definition of “apparent power” in Appendix F of this compliance filing, and has removed the definition that had been provided in subsection 6(2) of Rate DTS and Rate FTS in the 2010 ISO Tariff Application. The definitions do not differ in meaning or intent, and are provided for comparison below.

<table>
<thead>
<tr>
<th>Consolidated Glossary Definition (New)</th>
<th>Rate DTS and Rate FTS Definition (Old)</th>
</tr>
</thead>
<tbody>
<tr>
<td>“apparent power” means the total power, in MVA, in an alternating current power system and is calculated as the vector sum of real power and reactive power.</td>
<td>Metered apparent power, in MVA, comprises both real power and reactive power and is the product of metered voltage and metered current.</td>
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</table>

Finally, in its written argument (section 1.1, pages 3-5), the AESO proposed that the definition of “good electric industry practice” be updated in response to comments received during consultation on definitions used in the ISO rules. The definition of “good electric industry practice” became effective on December 1,
2010 for use in ISO rules and Alberta reliability standards, following a filing and notice process pursuant to subsection 20.2(1) of the *Electric Utilities Act*. The definition approved for ISO rules and Alberta reliability standards has slightly different wording from the definition included in the AESO’s argument, but retains the same meaning and intent. The AESO accordingly has included the definition of “good electric industry practice” that was approved for ISO rules and Alberta reliability standards in Appendix F of this compliance filing. That definition and the version included in the AESO’s argument are provided for comparison below.

<table>
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<tr>
<th>Consolidated Glossary Definition (New)</th>
<th>Definition Proposed in AESO Written Argument (Old)</th>
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<tr>
<td>“good electric industry practice” means the standard of practice attained by exercising that degree of knowledge, skill, diligence, prudence and foresight which would reasonably and ordinarily be expected from a skilled and experienced person engaged in the same type of undertaking in the same or similar circumstances, including determining what is reasonable in the circumstances having regard for safety, reliability and economic considerations but is not intended to be limited to the optimum practice, method or act, to the exclusion of all others, and rather is intended to include practices, methods and acts generally accepted in Alberta.</td>
<td>“good electric industry practice” means the standard of practice attained by exercising that degree of knowledge, skill, diligence, prudence and foresight which would reasonably and ordinarily be expected from a skilled and experienced person engaged in the same type of undertaking in the same or similar circumstances, and:</td>
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<tr>
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<td>(i) includes determining what is reasonable in the circumstances having regard for safety, reliability and economic considerations; and</td>
</tr>
<tr>
<td></td>
<td>(ii) is not intended to be limited to the optimum practice, method or act, to the exclusion of all others, but rather is intended to include practices, methods and acts generally accepted in Alberta and neighbouring jurisdictions.</td>
</tr>
</tbody>
</table>

The AESO considers that all of the changes to the definitions discussed above are minor in nature and do not affect the intent, interpretation, or applicability of those definitions. The changes are included in this compliance filing simply to achieve full consistency of definitions throughout the AESO’s authoritative documents. A blackline comparison of the definitions included in Appendix F definitions and those originally-filed is provided as Appendix I to this compliance filing and identify the specific changes summarized above.
16 Indicate AESO Has Final Oversight of Good Electric Industry Practice

**Direction**

Nonetheless, given the concerns of parties and the practical implications that could arise, the Commission directs that the determination of facilities in excess of GEIP take a similar approach as the framework provided in section 13 of the Transmission Regulation. Specifically, the Commission finds that the AESO can delegate the determination of facilities in excess of GEIP to TFOs; however, the AESO should review and approve any determination prepared under the delegation. Given the legislative framework and practical implications, the Commission considers that the AESO should retain final oversight over GEIP and the connection process including preparation of connection proposals by market participants, to ensure that there is non-discriminatory access to the system for all market participants. [page 72, paragraph 390]

**Response**

The refiled tariff in Appendix E of this compliance filing includes final oversight by the AESO over good electric industry practice and preparation of connection proposals.

As discussed in response to Direction 17 on the next page, subsection 4 of section 8 of the refiled tariff has been revised to indicate that the AESO is responsible for deeming facilities to be in excess of those required by good electric industry practice.

Subsection 5(4) of section 4 of the refiled tariff continues to indicate that a connection proposal prepared by a market participant will be reviewed by the AESO, have deficiencies identified by the AESO, and will be accepted by the AESO only after deficiencies, if any, have been addressed. The AESO considers that these provisions demonstrate that the AESO has final oversight of connection proposals prepared by market participants.
17 Clarify AESO Responsibility for Deeming Facilities in Excess of Good Electric Industry Practice

**Direction**
61 The Commission directs the AESO to revise section 8, subsection 4 of the T&Cs to clarify that a market participant must pay any participant-related costs of facilities which are deemed, in the opinion of the ISO, to be in excess of those required by GEIP. [page 72, paragraph 391]

**Response**
62 The AESO has revised subsection 4 of section 8 of the refiled tariff in Appendix E of this compliance filing to indicate that a market participant must pay any participant-related costs of facilities which the AESO deems to be in excess of those required by good electric industry practice.
18 Revise Operations and Maintenance Charge Provision in Section 8 of Tariff

**Direction**

For these reasons, the Commission directs the AESO to eliminate the proposed Prepaid O&M charge in its T&Cs. The AESO is directed to add to its T&Cs a provision that will charge customers requesting optional facilities deemed to be in excess of GEIP the full incremental maintenance cost, incremental operations cost, and overheads associated with the operation and maintenance of those facilities. The charge should be customer specific and recovered as it is currently, as a construction contribution. It is anticipated that the customer making the request for optional facilities deemed to be in excess of GEIP will be required to estimate the incremental operations and maintenance costs and that the estimate must be agreed to by the AESO. The testimony of the AESO and other parties suggests that this will only be required in exceptional cases. [pages 89-90, paragraph 486]

**Response**

The AESO has revised subsection 9 of section 8 of the refiled tariff in Appendix E of this compliance filing to indicate that:

- a market participant must pay, as part of the construction contribution, an operations and maintenance charge added to the cost of facilities which are deemed to be in excess of those required by good electric industry practice,
- the charge will be estimated by the market participant and agreed to by the AESO, and
- the charge will include the full incremental maintenance cost, incremental operations cost, and overheads associated with the operations and maintenance of the facilities which are deemed to be in excess of those required by good electric industry practice.

Direction

Consequently, the Commission wishes to better understand the impact that the ADC’s proposal may have on the AESO and on other market participants. Therefore the Commission directs the AESO to provide a report to the Commission on this proposal at the time of its Refiling which will indicate specifically:

(a) the number of market participants that would reasonably be expected to take advantage of the notice relief sought by the ADC;
(b) the revenue impact if all market participants identified in part (a) were to exercise this option and reduce their DTS demand; and
(c) an assessment of whether it is feasible to apply incentives in specific regions and at a specific time in order to realize benefits such as capital deferral, or reductions in TMR or isolated generation fuel costs.

Upon receipt of this information, the Commission will make a further determination on the ADC’s proposal.

Response

The AESO has examined the potential impact of ADC’s proposal and provides the following report of its findings.

The proposal as summarized in Decision 2010-606 (page 92, paragraph 500) was “that it may be desirable to augment incentives for market participants to pursue energy reduction initiatives in circumstances where it is clear that there is no risk of stranded investment and where there may be other benefits such as capital deferral or reductions in TMR or isolated generation costs.” The AESO therefore investigated the provision of notice relief contingent on three conditions:

(1) implementation of energy reduction initiatives,
(2) no risk of stranded investment, and
(3) other benefits such as capital deferral or reductions in TMR or isolated generation costs.

When examining those conditions, the AESO notes that both its current and proposed tariffs allow a 10% reduction in metered demand without limiting bill reductions due to the 90% ratchet and 90% of contract capacity components of billing capacity. Transmission revenue would therefore generally not be impacted by the provision of notice relief if metered demand would be reduced by less than 10%, as there would be no amounts which would need to be waived associated with a reduction of less than 10%.

Number of Market Participants That Would Take Advantage of Notice Relief

Having consideration for the point just discussed, it is difficult to estimate the number of market participants that would implement energy reduction initiatives that would reduce metered demand by more than 10%.

The AESO considers it unlikely that a demand reduction of more than 10% at a transmission point of delivery could be reasonably achieved by a distribution system owner serving multiple distribution-connected end-use customers from that point of delivery. It seems more probable that demand reductions
of more than 10% would occur where transmission service is provided to a single end-use customer. However, that customer could be either

- a “direct-connected” end-user who has arranged directly with the AESO for system access service under section 101(2) of the *Electric Utilities Act*, or
- a transmission-connected end-user served by a distribution system owner as its single customer at a transmission point of delivery.

72 About 36%, or 182, of the AESO’s current transmission points of delivery provide system access service to such end-users.

73 The AESO does not know the specific technical or economic feasibility of implementing energy reduction initiatives for those market participants, or the likelihood that such initiatives would achieve more than a 10% reduction in metered demand. However, based on general familiarity with demand response and energy reduction initiatives in other jurisdictions, the AESO considers that potentially 20% of direct-connected and transmission-connected end-use customers might implement energy reduction initiatives with more than 10% reduction in metered demand. Therefore, the AESO estimates that 36 market participants (20% × 182) might take advantage of notice relief for implementation of energy reduction initiatives.

74 The AESO has discussed this estimate with ADC, and understands that ADC does not consider it unreasonable.

75 The provision of notice relief would also be contingent on no risk of stranded investment. As discussed by the AESO during the 2010 ISO tariff proceeding and summarized in the AESO’s written argument (section 5.5.2, page 56, paragraph 311), “It is not practical to allocate the costs of such [local system] facilities to individual market participants to determine [if] ‘unrecovered investment’ existed.” However, for the purpose of qualifying for notice relief, the AESO suggests that risk of stranded investment could be considered low if a market participant had not increased contract capacity in the ten years prior to the energy reduction initiative. Such a consideration would suggest that the market participant has not been a direct factor causing a need for local system expansion over the prior decade.

76 The AESO has not been able to review all contract capacity changes related to the end-use customers discussed above. However, based on the frequency of requests for contract capacity increases over the past few years, the AESO estimates that contract capacity increases might be requested by about one-third of large end-use customers over a ten-year period.

77 Therefore, if notice relief would not be available where contract capacity had increased within the past ten years, the AESO estimates that 24 market participants (two-thirds of 36) might be eligible for and take advantage of notice relief for implementation of energy reduction initiatives.

78 The proposal summarized in Decision 2010-606 also suggested the provision of notice relief could additionally reflect other benefits such as capital deferral or reductions in TMR or isolated generation costs. The AESO considers that subsection 5(6)(b) of section 9 of the refiled tariff in Appendix E of this compliance filing already provides for the waiver of payments in lieu of notice where transmission system benefits arise from reductions of contract capacity. In other words, the tariff already allows for notice relief
where transmission system benefits result from a demand reduction, whether that demand reduction is associated with an energy reduction initiative or due to some other cause. The AESO concludes there would be no additional impact from further consideration of transmission system benefits in the context of energy reduction initiatives.

In conclusion, the AESO estimates that 24 market participants, representing about 5% of the total number of Rate DTS points of delivery, would reasonably be expected to take advantage of notice relief for energy reduction initiatives.

Revenue Impact If Eligible Market Participants Took Advantage of Notice Relief

The revenue impact would generally vary in proportion to the reductions expected from the market participants’ energy reduction initiatives. As discussed above, demand would need to be reduced by more than 10% before ratchets and contract capacities would begin to impact bills for system access service. Based on general familiarity with demand response and energy reduction initiatives in other jurisdictions, the AESO considers that demand reductions potentially as great as 20% could be achieved by the small number of direct-connected and transmission-connected end-use customers discussed above.

The AESO has discussed this estimate with ADC as well, and understands that ADC does not consider it unreasonable.

There are potentially two different revenue impacts that could result if market participants elected to take advantage of notice relief and implement energy reduction initiatives.

The larger revenue impact would result if the notice provisions in the AESO's current tariff are a real and material barrier to the implementation of energy reduction initiatives. If the notice provisions are a barrier and that barrier is removed, then the total transmission revenue at a point of delivery would be expected to decrease more-or-less in proportion to the resulting demand reduction, assuming that other aspects of the service (such as load factor) remain generally the same.

The AESO has estimated the total transmission revenue reduction that would occur at 24 randomly-chosen points of delivery out of the 182 direct-connected and transmission-connected end-use customers discussed above. If the demand and energy at those sites were permanently reduced by 20%, the AESO estimates a total permanent transmission revenue reduction of about $3.9 million per year over those points of delivery. This estimate is based on Rate DTS of the refiled tariff in Appendix E of this compliance filing, and excludes any associated reductions in energy market commodity charges.

As discussed above, this revenue reduction assumes the notice provisions in the AESO's current tariff are a real and material barrier to the implementation of energy reduction initiatives. The AESO considers this to generally be unlikely, as energy market commodity savings are usually significantly larger than the impact of the tariff’s notice provisions, as discussed during the 2010 ISO tariff proceeding and summarized in the AESO’s reply argument (section 5.5, page 38, paragraph 182).

If the notice provisions are generally not a barrier to the implementation of energy reduction initiatives, then a different and smaller revenue impact would result if the notice provisions were waived. This different impact arises if the notice provisions are considered to represent an unnecessary or inappropriate “penalty”
against an energy reduction initiative that is implemented to achieve energy market commodity savings and savings in the variable and coincident demand components of Rate DTS.

Under such a view, the revenue impact is limited to the foregone payments in lieu of notice that would otherwise be required under subsection 5(3) of section 9 of the refiled tariff. The AESO has estimated the payments in lieu of notice that would be required at the same 24 randomly-chosen points of delivery discussed above. If the contract capacities at those sites were permanently reduced by 20% without notice, the AESO estimates the one-time payments in lieu of notice would total about $2.5 million. This amount represents the present value of the differences in local system charges only, with and without the contract capacity reductions over the five-year notice period.

The AESO considers the second, smaller one-time revenue impact of $2.5 million to be more reasonably attributable to notice waivers for energy reduction initiatives. The AESO also expects that such an impact would be spread over two or three years, as it generally takes time for market participants to plan and implement energy reduction initiatives.

The impacts discussed above were based on 24 randomly-chosen points of delivery out of the AESO’s 182 direct-connected and transmission-connected end-use customers. The AESO has examined the sensitivity of the results to that assumption, by creating similar estimates assuming that 80% of the end-use customers who implement energy efficiency initiatives have higher-than-average load factor. With greater participation from high load factor market participants:

- the total transmission revenue reduction is estimated to increase to $5.6 million per year based on a permanent 20% demand and energy reduction (compared to $3.9 million per year from the random sample), and
- the foregone payment in lieu of notice one-time impact is estimated to increase to $3.3 million (compared to $2.5 million from the random sample).

In conclusion, the AESO estimates a potential one-time revenue reduction of $2 million to $4 million arising from market participants reasonably taking advantage of notice relief for energy reduction projects, where those amounts represent the range of foregone payments in lieu of notice that would occur over two to three years.

Feasibility of Incentives to Realize Transmission System Benefits

As already discussed above, the AESO considers that subsection 5(6)(b) of section 9 of the refiled tariff already provides for the waiver of payments in lieu of notice where transmission system benefits arise from reductions of contract capacity. At this time the AESO considers such a waiver to represent a reasonable and appropriate “incentive” for energy reduction initiatives in specific transmission system regions. The determination of transmission system benefits is specific to individual circumstances and is accordingly evaluated on a case-by-case basis.

The AESO is interested in how energy reduction initiatives and other market participant responses can assist in managing transmission system reliability and contribute to a fair, efficient, and openly competitive electricity market. The AESO continues to have ongoing discussions with stakeholders on these matters, and may pursue specific initiatives in the future.
Further Determination by the Commission

After reviewing the above information, if the Commission determines it would be appropriate to provide notice relief for energy reduction initiatives, the AESO suggests such a provision could be accommodated in subsection 5(6) of section 9 of the refiled tariff. Specifically, the AESO suggests the following alternate provisions could replace the refiled subsection 5(6):

(6) If the ISO considers that circumstances warrant, the ISO may waive or reduce the requirement for payment in lieu of notice where:

(a) contract capacity is transferred to a system access service of the same market participant at a nearby transmission substation;

(b) transmission system benefits arise from the reduction or termination of contract capacity, which benefits may include relief of regional transmission constraints, removal of capacity limitations which would restrict system access service to other market participants or avoidance of future upgrades to the transmission system; or

(c) the reduction of contract capacity results from an energy or demand reduction initiative of the market participant who:

(i) provides to the ISO a clear, thorough and convincing case, with supporting facts, that demonstrates the energy or demand reduction resulting from the initiative and

(ii) during the ten (10) years prior to the reduction in contract capacity becoming effective, has not increased contract capacity at the point of delivery at which the reduction in contract capacity will occur.

The AESO considers that, given the limited nature of the notice relief discussed above, there should no onerous monitoring or reporting requirements beyond the provision of a clear business case as described in part (c)(i) of the above alternate provisions of subsection 5(6):
20 Provide the Present Value of Investment for Incremental Changes to Contract Capacity

**Direction**

The Commission directs the AESO to amend its proposed T&Cs to ensure that the intention of Article 9.7(a)(i) of the AESO’s current T&Cs is restored. The AESO should provide its proposed amendment and any associated rationale at the time of its Refiling Application. [page 95, paragraph 512]

**Response**

Article 9.7(a)(i) of the current terms and conditions states:

9.7 Staged Load & Contract Capacity Increases

(a) Where material increases or decreases in Contract Capacity are contemplated at a POC and contracted for in the original System Access Service Agreement then:

(i) Local investment for projects with expected material increases or decreases in contract load will be determined at the start of the project by taking the present value of the local investment in the incremental load for the remaining contract term ....

The AESO has revised subsection 8(6) of section 8 of the refiled tariff in Appendix E of this compliance filing to restore the intent of Article 9.7(a)(i), as follows:

8(6) If a market participant includes increases or decreases to contract capacity over the investment term for a connection project, the local investment will be the sum of the investment for each incremental amount of contract capacity, which will be:

(a) calculated in accordance with subsections 8(4) and 8(5) above, based on each increment of contract capacity and the years for which each increment is contracted, and

(b) discounted from the beginning of the first month in which the increment of contract capacity exists back to the date of commercial operation of the connection project, using the discount rate provided in subsection 11 below.

The AESO considers that the revised subsection 8(6) provides investment for incremental contract capacity in part (a) and takes the present value of that investment in part (b), consistent with Article 9.7(a)(i) of the current terms and conditions.

The AESO notes that investment for contract capacity that exists on the date of commercial operation will not be discounted, as that date will also represent the beginning of the first month in which the contract capacity exists. The AESO considers this is also consistent with Article 9.7(a)(i) of the current terms and conditions.
21 Address Cost Recovery for PSS or AVR Additions to Regulated Generating Units

**Direction**
Specifically, the Commission considers that the cost implications were not adequately addressed in this proceeding and therefore declines to approve the deletion of Article 4.4 from the T&Cs at this time. The Commission directs the AESO in its Refiling Application to explain how the AESO intends to address cost recovery for directions to regulated generators to install or upgrade PSS/AVR equipment in other authoritative documents. The Commission will make a further determination on the AESO’s proposal to eliminate Article 4.4 of the T&Cs following its consideration of the Refiling Application. [page 96, paragraph 520]

**Response**

Article 4.4 of the current terms and conditions includes the following provisions for cost recovery when a regulated generator is required to install or upgrade a power system stabilizer (PSS) or automatic voltage regulator (AVR):

If the AESO requires PSS or AVR to be added to a currently regulated generator in the future, the AESO will pay any costs prudently incurred in the installation of the PSS or AVR and will recover prudently incurred costs from tariff(s) approved by the AUC. In the event the AUC determines that costs incurred by the currently regulated generators in the installation of the PSS or AVR cannot be recovered in rates charged by the AESO, then the Customer who has received the benefit of such amounts shall reimburse the AESO for such amounts. If the excitation system of an existing regulated or unregulated generator to which Article 4.4 does not apply is rebuilt or replaced, the new excitation system must be suitable for PSS, and a PSS/AVR must be installed.

Subsection 3(2) of section 3 of the originally-proposed ISO tariff stated, “A market participant is responsible for any costs arising from changes to its facilities required as a result of … changes to requirements, obligations and guidelines that apply to the connection ….” The AESO has incorporated the cost recovery provisions of current Article 4.4 by making the market participant’s cost responsibility in proposed section 3 subject to the following exception:

(3) When the ISO requires the installation of an automatic voltage regulator or power system stabilizer on a regulated generating unit listed in Appendix A of the ISO tariff, the ISO will pay to the owner of the generating unit all costs prudently incurred in the installation of the automatic voltage regulator or power system stabilizer, subject to the approval of the Commission for the recovery of such costs through the ISO tariff.

The AESO notes that the final sentence of current Article 4.4 discusses circumstances where Article 4.4 does not apply. The AESO considers such circumstances to already be addressed in the originally-proposed subsection 3(2) of section 3.

The above revision is included in subsection 3 of section 3 of the refiled tariff in Appendix E of this compliance filing.
Revert to Current Tariff Description of System-Related Costs

**Direction**

105 The AESO is directed to revise subsection 3(3) of section 8 of its proposed T&Cs to reflect the principles and criteria for classifying costs as system costs set out in Article 9.3(c) of the AESO’s current T&Cs in its Refiling Application. [page 96, paragraph 522]

**Response**

106 Article 9.3(c) of the current terms and conditions includes the following provisions for classifying costs as system costs:

9.3(c) System-related costs are those project costs associated with:

(i) Looped transmission facilities;

(ii) Radial transmission extensions if the transmission development plan (as that plan exists on the date the project is Commissioned) proposes that the Radial transmission extension becomes Looped within five years. The Customer will pay the cost of advancing that part of the project from the date established in the transmission development plan, calculated as the difference between the present values of the capital costs of the advanced and as-planned projects using the discount rate as determined under Article 9.14; and

(iii) Where, in the sole opinion of the AESO, economics or system planning dictate that a facility larger than that required to serve the Customer is to be installed, then the AESO will classify that portion of the project deemed to be in excess of the Customer’s needs as system-related costs. As the need to serve additional POCs arises, these system-related costs may be reclassified as Customer-related costs and allocated to the new Customers. The capacity between the Customer’s requirements and the minimum size of facilities required to serve the Customer is not considered to be in excess of the Customer’s requirements.

107 The system-related classification of looped transmission facilities in Article 9.2(c)(i) is addressed in subsection 3(3)(a) of section 8 of the originally-proposed ISO tariff.

108 The system-related classification of radial transmission lines that are planned to be looped in Article 9.2(c)(ii) was generally addressed in subsection 3(3)(f) of section 8 in the originally-proposed ISO tariff. That subsection has been revised to include the conditions that the lines must be planned to be looped within five years, in the refiled tariff in Appendix E of this compliance filing. The participant-related classification of the cost of advancement is addressed in subsection 3(2)(l) of section 8 of the originally-proposed ISO tariff.
The system-related classification of facilities the AESO plans in excess of those required to serve the market participant is addressed in subsection 3(3)(g) of section 8 of the originally-proposed ISO tariff. The reclassification of those costs as participant-related when the facilities are used to meet the requirements of another market participant’s connection project is addressed in subsection 3(2)(m) of section 8 of the originally-proposed ISO tariff.

The remaining provisions of subsection 3(3) of section 8 of the originally-proposed ISO tariff (namely, subsection 3(3)(b) through 3(3)(e)) have been deleted in the refiled tariff in Appendix E of this compliance filing, with the remaining subsections renumbered accordingly.
Consistent with the Commission's prior findings in respect of Future Cost Causation Studies in section 6.3 of this Decision, the Commission directs the AESO to file its next major tariff application no later than March 31, 2013. [page 100, paragraph 548]

The AESO will file its next comprehensive tariff application no later than March 31, 2013.
3   2011 Tariff Update

In Decision 2010-606 (page 99, paragraph 537), the AESO’s proposed annual tariff update was summarized as follows:

In conjunction with its proposal for major updates, the AESO proposed to make annual tariff update filings involving the following three principal components:

- an annual revenue requirement update using the approach to the wires cost forecast as described in section 2.2 of the Application, plus forecasts for ancillary services costs, losses costs and administration costs approved by the AESO Board for the forecast year;
- revised rate levels for each AESO rate calculated from the forecast revenue requirement and forecast billing determinants using rate calculations and rate design approved in the most recent comprehensive tariff application; and
- annual updates to investment amounts approved in the most recent comprehensive tariff reflecting an escalation factor based on the most recent Conference Board of Canada Alberta consumer price index (CPI).

The Commission approved the proposal (pages 100-101, paragraphs 547-551) in its findings, as follows.

The Commission finds that the AESO’s request in section 8.1 of the Application to have major tariff applications at intervals and much simpler update applications on an annual basis effectively formalizes the AESO’s existing practice as approved in Decision 2009-141 [on the AESO’s 2009 Rates Update Application]. The Commission considers that an annual revenue requirement and rate update may benefit customers by limiting potential misallocations that might occur if the AESO were to rely exclusively on Rider C to allocate periodic revenue/cost imbalances to its customers.

Consistent with the Commission’s prior findings in respect of Future Cost Causation Studies in section 6.3 of this Decision, the Commission directs the AESO to file its next major tariff application no later than March 31, 2013.

In the AESO’s 2009 tariff update, the AESO did not request nor did the Commission approve the concept that investment levels should be updated between major tariff updates. In this tariff proposal, the Commission accepts the AESO’s proposal to incorporate a formulaic update into its annual tariff updates. The Commission’s approval of an annual update to investment levels represents a significant benefit to prospective connecting customers as compared to the status quo. The Commission notes that this benefit was, in part, taken into account in the Commission’s findings respecting the investment allowance multiplier approved in section 10.4.2.1 of this Decision.

The Commission is satisfied that the composite price index developed by the AESO to escalate projects costs is reflective of transmission costs in Alberta.
The Commission finds that it is reasonable to use the composite price index to determine maximum investment levels in a tariff application and annually between full tariff applications and this provides a mechanism to adjust the contribution formula on an ongoing basis to recognize escalation in transmission costs. The Commission approves this proposal as filed.

The AESO’s 2010 ISO Tariff Application was prepared using its forecast 2010 revenue requirement and forecast 2010 billing determinants, and both represented the best information available at the time of filing. Since the filing, the AESO Board has approved costs for 2011 related to ancillary services, transmission line losses, and the AESO’s own administration, and transmission facility owner costs for 2011 are in various stages of application and review. The AESO also notes that the effective date of the applied-for tariff will be in 2011.

The AESO accordingly considers it reasonable to incorporate the 2011 tariff update into this Decision 2010-606 compliance filing, and proposed to the Commission to do so by letter dated January 14, 2011. After a process allowing interested parties to comment and the AESO to reply, the Commission approved the AESO’s proposal by letter dated January 26, 2011.

The following sections and related appendices provide the details of the 2011 ISO tariff update included in this compliance filing.

3.1 AESO 2011 Revenue Requirement

The AESO’s revenue requirement consists of costs related to wires, ancillary services, transmission line losses, and the AESO’s own administration (which includes other industry costs and general and administrative costs). For 2011, those costs are forecast to total $1,086.2 million. The AESO’s forecast costs for 2011 are detailed in column A of Table 3-2, which for comparison also includes refiled costs for 2010 in Column C and recorded costs for 2009 and 2008 (as provided in the AESO’s 2009 deferral account reconciliation) in columns D and E, respectively.

The 2011 forecast costs represent an increase of $43.5 million (4.2%) over the $1,042.7 million of total costs for 2010 as provided in the Decision 2010-606 compliance filing discussed in section 2 of this application. As summarized in Table 3-1 below, the increase results from a forecast 21.8% increase in wires cost reflecting recent approvals and applications for transmission facility owner tariffs, offset by forecast 33.5% and 30.3% decreases in ancillary services costs and losses costs, respectively, reflecting primarily a forecast 28% decrease in pool price.

Although deferral account riders and later reconciliations allow the AESO to recover variances between base rate revenue and actual costs, use of deferral accounts generally provides imprecise and delayed allocation of costs. It is therefore preferable to update rates to reflect significant changes in costs, as included in this tariff update.
### 3.1.1 AESO Board Approval of Costs

The AESO is not seeking approval in this application of its 2011 forecast revenue requirement. The AESO’s forecast costs are approved through other processes, which are provided for in relevant legislation. These costs, as provided in column B of Table 3-2, were addressed in the AESO 2011 Updated Business Plan and Budget Proposal dated October 29, 2010 which is provided as Appendix G to this application.

The AESO’s 2011 forecast costs, including their approval processes, are discussed below.

(a) Wires-related costs reflect the amounts paid by the AESO to owners of transmission facilities (TFOs) in the TFO tariffs approved by the Commission under section 37 of the Act. (The wires costs forecast included in the AESO 2011 Updated Business Plan and Budget Proposal reflects TFO tariffs applied for or approved by the Commission at the time the AESO budget was prepared in late 2010, as discussed in more detail in section 3.1.2 below.)

(b) Ancillary services costs reflect recovery of the prudent costs incurred by the AESO related to the provision of ancillary services acquired from market participants under subsection 30(4) of the Act.

(c) Losses costs reflect recovery of the prudent costs of transmission line losses under subsection 30(4) of the Act.

(d) Administrative costs reflect the transmission-related costs and expenses incurred by the AESO in accordance with subsection 1(1)(g) of the Transmission Regulation.

The ancillary services costs, losses costs, and administrative costs described above are approved by the AESO Board (acting as the “ISO members” described in section 8 of the Act) in accordance with the Transmission Regulation. Section 3 of the Transmission Regulation addresses consultation and approval of those costs and requires that the AESO consult with market participants with respect to proposed costs to be approved by the AESO Board. Subsections 46(1), 48(1), and 48(2) of the Transmission Regulation also provide that these costs, once approved by the AESO Board, must be considered as “prudent” by the Commission unless an interested person satisfies the Commission otherwise.

The practice established by the AESO to carry out consultation on ancillary services, losses, and administrative costs is the Budget Review Process. The Budget Review Process is a transparent stakeholder process which provides a prudence review with input from stakeholders. At the conclusion of
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<td>AltaLink</td>
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<td>321.0</td>
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<td>3</td>
<td>Isolated Generation</td>
<td>(3.0)</td>
<td>(3.2)</td>
<td>(4.4)</td>
<td>(3.3)</td>
</tr>
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<td>317.9</td>
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<td>Subtotal IBOC/LBC SO Costs</td>
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<td>6.7</td>
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<td>TOTAL WIRES COSTS</td>
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<td>17</td>
<td>Active</td>
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<td>18</td>
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<td>24.4</td>
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<tr>
<td>19</td>
<td>Spinning</td>
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<td>17.0</td>
<td>38.1</td>
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<td>100.6</td>
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<td>22</td>
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</tr>
<tr>
<td>23</td>
<td>Regulating</td>
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<td>25</td>
<td>Spinning</td>
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### Table 3-2  AESO 2011 Forecast Revenue Requirement, $ 000 000 (continued)

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<th>Line No.</th>
<th>Description</th>
<th>2011 AESO Forecast</th>
<th>2010</th>
<th>2009</th>
<th>2008</th>
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<td>Refiled TFO Costs</td>
<td>Budget Proposal</td>
<td>Refiled</td>
<td>Recorded</td>
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<td>Brazeau Fast Ramp (Previously GRAS)</td>
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<td>28</td>
<td>Black Start</td>
<td>28.1</td>
<td>28.1</td>
<td>22.3</td>
<td>24.3</td>
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<td>29</td>
<td>Transmission Must Run (TMR)</td>
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<td>3.8</td>
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<td>30</td>
<td>Under Frequency Mitigation</td>
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<tr>
<td>31</td>
<td><strong>Subtotal Other Ancillary Services</strong></td>
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<td>33.8</td>
<td>29.7</td>
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<td>32</td>
<td>Poplar Hill</td>
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<td>2.1</td>
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<td>Interruptible Load Remedial Action Sch (ILRAS)</td>
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<td>Generator Remedial Action Schemes (RAS)</td>
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<td>-</td>
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<td>35</td>
<td><strong>Subtotal Poplar Hill/ILRAS</strong></td>
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<td>2.2</td>
<td>2.1</td>
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<td><strong>TOTAL ANCILLARY SERVICES</strong></td>
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<td><strong>TOTAL LOSSES COSTS</strong></td>
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<td>121.0</td>
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<td>Western Electricity Coordination Council (WECC)</td>
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<td>Share of EUB Overhead</td>
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<td><strong>TOTAL OTHER INDUSTRY COSTS</strong></td>
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<td>14.3</td>
<td>14.7</td>
<td>14.2</td>
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<td>43</td>
<td>Staff and Benefits</td>
<td>33.9</td>
<td>33.9</td>
<td>32.5</td>
<td>30.4</td>
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<td>44</td>
<td>Contract Services and Consultants</td>
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<td>9.5</td>
<td>9.8</td>
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<td>Rent</td>
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<td>3.3</td>
<td>2.7</td>
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<td>Administration</td>
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<td>5.0</td>
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<tr>
<td>47</td>
<td>Computer and Telecom Services and Maint</td>
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<td>5.3</td>
<td>5.3</td>
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<td>48</td>
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<tr>
<td>49</td>
<td><strong>Subtotal Administrative Costs</strong></td>
<td>58.4</td>
<td>58.4</td>
<td>53.5</td>
<td>52.3</td>
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Table 3-2  AESO 2011 Forecast Revenue Requirement, $ 000 000 (continued)

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<tr>
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<td>1.1</td>
<td>0.9</td>
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<td>51</td>
<td>Amortization and Depreciation</td>
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<td>5.0</td>
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<td>Subtotal General Costs</td>
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<td>TOTAL G&amp;A COSTS</td>
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<td>TOTAL G&amp;A AND OTHER INDUSTRY COSTS</td>
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<tr>
<td>55</td>
<td>TOTAL REVENUE REQUIREMENT</td>
<td>1,086.2</td>
<td>1,028.0</td>
<td>1,042.7</td>
<td>897.5</td>
<td>1,116.3</td>
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<td>CAPITAL</td>
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<td></td>
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<td></td>
</tr>
<tr>
<td>56</td>
<td>General Capital</td>
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<td>5.3</td>
<td>6.0</td>
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<td>Calgary Place Office Renovations</td>
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<td>58</td>
<td>Energy Management System (EMS) Upgrade</td>
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<td>Dispatch Tool Architecture Improvements</td>
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<td>60</td>
<td>TOTAL CAPITAL</td>
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<td>NA¹</td>
<td>5.3</td>
<td>14.3</td>
<td>14.1</td>
</tr>
</tbody>
</table>

Notes: ¹ The AESO’s actual capital expenditures (budgeted at $27.0 million for 2011) will be allocated to business functions on a project-by-project basis at year-end.
Numbers may not add due to rounding.

As part of the AESO Budget Review Process for its 2010 and 2011 budgets, AESO management consulted with stakeholders in a multi-year planning process that had been first established with stakeholders in 2009. Prior to the start of the 2011 fiscal year, the AESO accordingly reviewed the business initiatives that had been established the prior year and prepared a forecast to assess any budget changes required to deliver those business initiatives. Following the consultation with stakeholders and incorporating appropriate amendments arising from it, AESO management submitted the 2011 Updated Business Plan and Budget Proposal to the AESO Board on October 29, 2010. The document (provided as Appendix G of this application) includes details on the consultation process and on the proposal for the AESO’s business plan and budget as it relates to forecasted ancillary services costs, forecasted losses costs, and the AESO’s business priorities and budget for 2011. The 2011 Updated Business Plan and Budget Proposal was also provided to stakeholders and posted on the AESO website.
The AESO’s 2011 forecast costs were subsequently approved by the AESO Board on December 7, 2010. A Board Decision Document is in the process of being prepared and will be posted on the AESO website when available.

Additional information on the AESO’s business priorities and budget for 2011 is available on the AESO website at www.aeso.ca by following the path About AESO ► Our Business ► Business Plan and Budget ► 2011 Budget Review.

3.1.2 2011 Wires Costs

The 2011 forecast cost for wires is $786.2 million and represents about 72% of the AESO’s transmission revenue requirement. Wires costs include primarily wires-related costs of owners of transmission facilities as well as two small non-wires costs.

The 2011 Updated Business Plan and Budget Proposal discussed in section 3.1.1 above included wires-related costs based on the transmission facility owner tariffs approved by the Commission or applied for by the transmission facility owners at the time the AESO budget was prepared in late 2010. Those costs are included in column B, lines 1 through 10, of Table 3-2. Most of the transmission facility owner costs in column B reflect Commission approvals for 2010, that being the most recent year for which several tariff approvals had been issued or tariff applications had been filed at the time.

The Commission has subsequently issued decisions on, and applications have been filed for, additional 2011 tariffs of transmission facility owners. The AESO has therefore updated the 2011 wires costs in Table 3-2 to reflect these more recent approvals and applications.

The AESO has determined the 2011 wires costs for transmission facility owners using the approach described in section 2.2 of the AESO’s 2010 ISO Tariff Application (pages 14-15, paragraphs 48-56) and referred to in the extract from Decision 2010-606 at the beginning of section 3 in this application. Specifically, the AESO has included costs that reflect the status of each transmission facility owner’s application for its 2011 tariff.

(a) If a transmission facility owner has received final Commission approval for its 2011 tariff, the AESO has included the approved cost for that 2011 transmission facility owner tariff.

(b) If a transmission facility owner has applied for its 2011 tariff, the Commission has issued an initial decision on the application, and the transmission facility owner has submitted a refiling in compliance with the decision, the AESO has included the 2011 transmission facility owner tariff costs included in the refiling.

(c) If a transmission facility owner has applied for its 2011 tariff but the Commission has not yet issued an initial decision on the application or an initial decision has been issued but the TFO has not yet submitted its compliance refiling, the AESO has included the tariff costs most recently approved by the Commission on a final basis for the transmission facility owner plus 72% of any increase or decrease included in the transmission facility owner’s 2011 tariff application above or below the prior approved costs.
If a transmission facility owner has not yet applied for its 2011 tariff, the AESO has included the transmission facility owner tariff costs most recently approved by the Commission on either a final or interim basis.

As noted in the AESO’s 2010 ISO Tariff Application, the inclusion of 72% of applied-for increases or decreases in (c) above was determined from the percentages of applied-for changes which had received final approvals in recent transmission facility owner tariff applications, and is not meant to indicate any predetermination of the result of a transmission facility owner tariff proceeding, nor be interpreted as AESO support for any specific components of a transmission facility owner tariff application.

Rather than representing detailed or specific estimates, the approach used by the AESO is a simple, practical, and transparent means of addressing, to a reasonable extent, transmission facility owner tariff increases that are probable but have not yet been approved. It is recognized as an average and imprecise estimate that is used with the objective of reducing amounts that would otherwise be recovered through AESO deferral account riders and reconciliations. The AESO notes that actual transmission facility owner tariff costs as paid by the AESO will be recovered through the AESO’s tariff, and will include costs approved through transmission facility owner deferral accounts and other adjustments approved by the Commission.

The transmission facility owner tariff costs included in this application have been determined using the approach discussed above and are provided in Table 2-3 in Appendix B of this compliance filing. These costs are also included in column A of Table 3-2 above.

The wires costs included in this application are based on the following Commission decisions and transmission facility owner tariff applications.

**Line 1 AltaLink**

AltaLink has applied for 2011 transmission facility owner tariff costs of $368.0 million, which represents a $80.4 million increase over AltaLink’s 2010 tariff costs of $287.6 million (which is the transmission facility owner tariff costs most recently approved on a final basis for AltaLink, in Commission Decision 2010-409). The AESO has included $57.9 million (72%) of the applied-for increase in this application, for a forecast of $345.5 million of transmission facility owner tariff costs for AltaLink for 2011.

**Lines 2-4 ATCO Electric**

ATCO Electric has applied for 2011 transmission facility owner tariff costs of $350.1 million, which represents a $103.8 million increase over ATCO Electric’s 2010 tariff costs of $246.3 million (which is the transmission facility owner tariff costs most recently approved on a final basis for ATCO Electric, in Commission Decision 2010-056). The AESO has included $74.7 million (72%) of the applied-for increase in this application, for a forecast of $321.0 million of transmission facility owner tariff costs for ATCO Electric for 2011.

ATCO Electric’s transmission facility owner tariff costs are offset by payments to the AESO in respect of pool price for electric energy provided to isolated communities in accordance with the Isolated Generating Units and Customer Choice Regulation. The isolated generation cost offset was estimated at $3.0 million based on 2010 recorded volumes for isolated communities and the 2011 forecast pool price.

The 2011 net forecast cost for ATCO Electric is $318.0 million.
**Line 5 ENMAX Power Corporation**

ENMAX received approval for its 2010 transmission facility owner tariff in Commission Decision 2010-593, at a rate of $39.1 million for the period January 1, 2011 to June 30, 2011. ENMAX has not yet applied for its 2011 tariff. The AESO has accordingly used the transmission facility owner tariff costs most recently approved for ENMAX by the Commission (namely, the $39.1 million approved for 2010) as the forecast transmission facility owner tariff costs for ENMAX for 2011.

**Line 6 EPCOR Distribution & Transmission**

EPCOR has applied for 2011 transmission facility owner tariff costs, Decision 2010-591 was issued on the application, and EPCOR has submitted a refiling in compliance with that decision. The AESO has therefore included the refiling’s 2011 transmission facility owner tariff costs of $60.3 million for EPCOR in this application.

**Line 7 City of Lethbridge**

The 2011 forecast cost for Lethbridge transmission facility owner is $5.8 million as approved in Commission Decision 2010-411 released on August 24, 2010 on the City of Lethbridge 2009-2011 Transmission Facility Owner General Tariff Application Compliance Filing.

**Line 8 TransAlta Utilities Corporation**

TransAlta has not yet applied for its 2011 transmission facility owner tariff, so the AESO has used the transmission facility owner tariff costs most recently approved for TransAlta by the Commission. TransAlta tariff costs of $4.1 million (a continuation of TransAlta’s 2010 tariff costs) were approved on an interim basis in Decision 2010-486 for 2011, and the AESO has accordingly included that amount in this application.

**Line 9 City of Red Deer**


**Line 10 FortisAlberta (Farm Transmission)**

Section 32 of the Act requires the AESO to pay owners of electric distribution systems for “farm transmission costs” as defined in the Act. The 2011 forecast farm transmission cost for FortisAlberta is $4.5 million as approved in Commission Decision 2010-560 released on December 6, 2010 on the FortisAlberta 2010-2011 Phase I Compliance Filing.

**Lines 12-14 Non-Wires Costs**

The AESO includes as wires costs two cost components which are not related to transmission facility owners: Invitation to Bid on Credit (IBOC) costs and Location Based Credit Standing Offer (LBC SO) costs. These two programs were initiated to provide a non-wires solution to transmission wires issues in Alberta and their costs are included as wires costs for rate-setting purposes. The $6.7 million cost for the two programs was forecast by the AESO in conjunction with ancillary services costs and is approved by the AESO Board.
3.1.3 2011 Ancillary Services Cost

The 2011 forecast cost for ancillary services is $96.0 million and represents about 9% of the AESO’s transmission revenue requirement. Ancillary services, as defined in the Act, are services required to ensure that the interconnected electric system is operated in a manner that provides a satisfactory level of service with acceptable levels of voltage and frequency. The largest component of ancillary services costs is operating reserves, which are unloaded generating capacity that is available to respond to temporary shortfalls in supply caused by loss of a generating unit, loss of intertie capacity, or fluctuations in load.

Ancillary services cost is a function of volume forecasts and market-based commodity pricing forecasts. The 2011 forecast cost for ancillary services was based on a forecast average pool price of $46.74/MWh.

3.1.4 2011 Losses Cost

The 2011 forecast cost for transmission line losses is $121.0 million and represents about 11% of the AESO’s transmission revenue requirement as provided in Table 3-2. Losses are the energy lost on the transmission system when power is transmitted from suppliers to loads. Losses are the residual of the metered generation plus scheduled imports less scheduled exports and less metered loads.

Losses cost is a function of volume forecasts and market-based commodity pricing forecasts. The 2011 forecast cost for losses was based on a forecast average pool price of $46.74/MWh.

3.1.5 2011 Administrative Costs

The 2011 forecast cost for administration is $83.0 million and represents about 8% of the AESO’s transmission revenue requirement.

Administrative costs are defined in paragraph 1(1)(g) of the Transmission Regulation:

1(1)(g) “ISO’s own administrative costs” means

(i) the transmission-related costs and expenses of the ISO respecting the administration, operation and management of the ISO,

(ii) the transmission-related costs and expenses of the ISO respecting reliability standards and reliability management systems, and

(iii) the transmission-related costs and expenses required to be paid, or otherwise appropriately paid, by the ISO, except for the following:

(A) costs for the provision of ancillary services;
(B) costs of transmission line losses;
(C) amounts payable under TFO transmission tariffs;

The AESO Board approves the AESO’s administration costs in their entirety. However, the amounts recovered through the AESO’s tariff includes only the transmission-related portions of those costs, in accordance with paragraph 1(1)(g) of the Transmission Regulation. The AESO Board approval therefore includes the allocation of administrative costs between the three functions of the AESO, namely, transmission, energy market, and load settlement.
The allocation of the AESO’s administrative costs between the three AESO functions is provided in the 2011 Updated Business Plan and Budget Proposal (page 3) provided as Appendix G of this application. The transmission-related portions are included in the AESO’s transmission revenue requirement detailed in Table 3-2.

3.2 2011 Rates Update

The AESO’s 2010 rate calculations were revised in compliance with directions in Decision 2010-606, as discussed in section 2 of this application, and are provided in Appendix A.

For the 2011 tariff update, the AESO has utilized the same functionalization, classification, and allocation of the AESO’s revenue requirement as directed in Decision 2010-606. The AESO has similarly maintained the same design and structure of the AESO’s rates as directed in that decision.

The AESO has simply calculated the rate levels for each rate based on the 2011 forecast revenue requirement discussed above in section 3.1 of this application, using the rate calculations prepared in compliance with Decision 2010-606. More specifically, the AESO has used the 2010 rate calculations provided in Appendix A of this application as the template for the 2011 rate calculation. The 2011 rate calculations are in turn provided as Appendix B of this application, in Tables B5-1 through B5-13.

3.2.1 Specific Rate Changes

In addition to the overall updating of rates to reflect the AESO’s 2011 revenue requirement, the AESO provides the following comments on updates to some aspects of certain specific rates.

Fort Nelson Demand Transmission Service Rate FTS

Direction 7 of Decision 2005-096 incorporated in Rate FTS “a local system charge that represents the greater of the actual cost of the ATCO Electric line providing service to Fort Nelson or the charges that would accrue to BC Hydro using the DTS local system charge”. Since then, the actual cost of the ATCO Electric line has exceeded the charges that would accrue to BC Hydro under the Rate DTS local system charge. The actual cost of the ATCO Electric line has therefore established the Rate FTS local system charge beginning in 2006.

In 2011, however, the charges that would accrue to BC Hydro under the Rate DTS local system charge are greater than the actual cost of the ATCO Electric line. The Rate FTS local system charge has therefore been set to equal to the Rate DTS local system charge, consistent with the original direction regarding Rate FTS.

Primary Service Credit Rate PSC

Consistent with the calculation of the 2010 primary service credit, the 2011 primary service credit is calculated as:

- 79% of the first three capacity tiers (up to 40 MW) of the Rate DTS point of delivery charge;
- 100% of the fourth capacity tier (incremental capacity above 40 MW) of the Rate DTS point of delivery charge; and
- 79% of the fixed ($/month) component of the Rate DTS point of delivery charge.
As the Rate DTS point of delivery charge has been updated in this application, the AESO has corresponding updated the primary service credit as provided in Table 3-3 below. The primary service credit amounts determined in Table 3-3 are reflected in Rate PSC in the refiled tariff in Appendix E of this application.

<table>
<thead>
<tr>
<th>Rate Component</th>
<th>Rate DTS Charge</th>
<th>PSC Factor</th>
<th>Rate PSC Credit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Substation fraction</td>
<td>$8,544.00/month</td>
<td>79%</td>
<td>$6,750.00/month</td>
</tr>
<tr>
<td>First (7.5 × substation fraction) MW of billing capacity</td>
<td>$5,788.00/MW</td>
<td>79%</td>
<td>$4,573.00/MW</td>
</tr>
<tr>
<td>Next (9.5 × substation fraction) MW of billing capacity</td>
<td>$2,136.00/MW</td>
<td>79%</td>
<td>$1,687.00/MW</td>
</tr>
<tr>
<td>Next (23 × substation fraction) MW of billing capacity</td>
<td>$1,294.00/MW</td>
<td>79%</td>
<td>$1,022.00/MW</td>
</tr>
<tr>
<td>All remaining MW of billing capacity</td>
<td>$709.00/MW</td>
<td>100%</td>
<td>$709.00/MW</td>
</tr>
</tbody>
</table>

**Regulated Generating Unit Connection Costs in Rate STS**

The AESO most recently provided the derivation of the regulated generating unit connection costs (RGUCC) charge in an attachment to the AESO’s response to Information Request BR.AESO-018 (a) in its 2007 GTA proceeding. That attachment included a calculation of the RGUCC charge for each calendar year to 2020, based on the original determinations of the Alberta Energy and Utilities Board which established the RGUCC. In general, RGUCC charges decrease every year reflecting the on-going amortization of connection costs over the lives of the previously-regulated generating units.

In Decision 2007-106 on the AESO’s 2007 GTA, the Alberta Energy and Utilities Board commented (page 76), “The Board has reviewed this calculation and considers the AESO RGUCC appears to be reasonable.” The 2011 RGUCC value included in the attachment to Information Response BR.AESO-018 (a) is $236.76/MW compared to the 2010 RGUCC value of $236.35/MW. The slight increase in the RGUCC value from 2010 to 2011 reflects the original base lives of the EPCOR Clover Bar generating units expiring in 2010 (although the units were actually retired in 2005).

The regulated generating unit connection cost charge has accordingly been updated to $237.00/MW in Rate STS in the refiled tariff in Appendix D of this application, being the 2011 value included in the attachment to Information Response BR.AESO-018 (a) rounded to the nearest dollar.
As well, the EPCOR Clover Bar generating units have been deleted from the list of regulated generating units in Appendix A to the ISO tariff. As mentioned above, the base lives of those units expired in 2010 and the RGUCC charge in the 2011 ISO tariff would no longer apply to those units, even if they had continued to operate beyond 2010.

**Wind Forecasting Service Cost Recovery Rider J**

As indicated in subsection 2(4) of Wind Forecasting Service Cost Recovery Rider J, the AESO will adjust Rider J charges to reflect variances from the forecasts of cost and energy initially used to determine the values of the rider, and incorporate the adjustments in the rider in the following year. As Rider J will not be in effect until April 1, 2011, the energy and revenue amounts for 2010 have been updated to zero. As well, the energy and revenue amounts for 2011 have been updated to include forecasts for April to December rather than for January to December.

The effects of those changes are shown in subsection 2(2) of Rider J, and result in an increase in the charge for 2011 to $0.12/MWh from the original forecast of $0.11/MWh included in the 2010 ISO tariff application.

### 3.3 2011 Forecast Billing Determinants

The rate calculations in the 2011 tariff update are based on the AESO’s forecast of rate billing determinants for 2011. Those billing determinants were in turn based on the 2011 load forecast in the AESO’s *Future Demand and Energy Outlook (2009-2029)*, which is the AESO’s long-term load forecast prepared in accordance with the AESO’s duties under the Act and the *Transmission Regulation*.

The *Future Demand and Energy Outlook* includes a 20-year peak load and electricity consumption forecast for Alberta. The load forecast is generated from economic growth (gross domestic product or GDP) information, oilsands production forecasts, and population projections by select customer sectors, with regional adjustments based on historical results and customer-driven growth expectations. The AESO’s *Future Demand and Energy Outlook (2009-2029)* is available on the AESO website at www.aeso.ca by following the path Transmission ▶ Load Forecasting.

To develop the *Future Demand and Energy Outlook*, the AESO produces hourly load forecasts by metering point, including adjustments for load supplied through on-site generation. Metering points are then correlated to service accounts to develop annual profiles for forecast hourly load at each point of delivery. Billing determinants are calculated directly from the per-point-of-delivery forecast hourly load profiles. In addition, the billing determinant for billing capacity also incorporates:

- current contract capacity and known contract capacity changes during the forecast year for each service account; and
- ratchets based on historical peak demand information in the AESO’s billing system as well as new forecast peak demands during the forecast year for each service account.

Substation fractions are applied to billing capacities to develop billing determinants for each of the point of delivery charge capacity tiers. Substation fractions are also applied to develop the billing determinant for “equivalent” market participants, used in the calculation of the fixed ($/month) component of the Rate DTS point of delivery charge.
Although the 2011 billing determinants are based on the 2011 load forecast in the AESO’s *Future Demand and Energy Outlook* (2009-2029), the billing determinants were reviewed and adjusted to reflect known delays to the expected magnitude and timing of contract capacity changes and on-site generation additions since the *Demand and Energy Outlook* was prepared. In addition, some delayed and cancelled projects have been removed from the forecast number of market participants in 2011. Offsetting those reductions were recent increases to metered demand peaks for some large services, which resulted in ratchet-based increases to the third and fourth billing capacity tiers which apply to incremental billing capacity above 23 MW and 40 MW, respectively.

The AESO notes that the per-point-of-delivery annual profiles for forecast hourly load as well as the per-point-of-delivery billing determinants are considered confidential information which should not be made publicly available. Forecast hourly load data for individual points of delivery and future contract capacity changes are clearly of a commercial and financial nature that is consistently treated as confidential by the AESO. The AESO further considers that the provision of such detailed information could result in harm to a market participant’s competitive position by disclosing patterns and trends that could be used to advantage by a competitor.

As has been the traditional practice in AESO rate calculations, the billing determinants used in the 2011 rate calculations are provided in aggregate, in Table B5-10 in Appendix B of this application.

<table>
<thead>
<tr>
<th>DTS Billing Determinant</th>
<th>Units</th>
<th>2011 Forecast</th>
<th>2010 Forecast</th>
<th>Increase (Decrease) Amount</th>
<th>%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coincident Metered Demand</td>
<td>MW-months</td>
<td>89,069.9</td>
<td>89,552.2</td>
<td>(482.3)</td>
<td>(0.5%)</td>
</tr>
<tr>
<td>Billing Capacity</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Total Billing Capacity</td>
<td>MW-months</td>
<td>126,637.7</td>
<td>124,997.0</td>
<td>1,640.7</td>
<td>1.3%</td>
</tr>
<tr>
<td>• First (7.5×SF) MW</td>
<td>MW-months</td>
<td>32,152.6</td>
<td>32,838.7</td>
<td>(686.2)</td>
<td>(2.1%)</td>
</tr>
<tr>
<td>• Next (9.5×SF) MW</td>
<td>MW-months</td>
<td>28,072.3</td>
<td>28,140.4</td>
<td>(68.0)</td>
<td>(0.2%)</td>
</tr>
<tr>
<td>• Next (23×SF) MW</td>
<td>MW-months</td>
<td>33,039.5</td>
<td>32,193.2</td>
<td>846.3</td>
<td>2.6%</td>
</tr>
<tr>
<td>• All Remaining MW</td>
<td>MW-months</td>
<td>33,373.3</td>
<td>31,824.7</td>
<td>1,548.6</td>
<td>4.9%</td>
</tr>
<tr>
<td>Highest Metered Demand</td>
<td>MW-months</td>
<td>108,195.1</td>
<td>105,817.0</td>
<td>2,378.1</td>
<td>2.2%</td>
</tr>
<tr>
<td>Metered Energy (All Hours)</td>
<td>GWh</td>
<td>55,471.0</td>
<td>55,865.5</td>
<td>(394.6)</td>
<td>(0.7%)</td>
</tr>
<tr>
<td>DTS Market Participants</td>
<td>customer-months</td>
<td>4,784.0</td>
<td>4,908.6</td>
<td>(124.6)</td>
<td>(2.5%)</td>
</tr>
<tr>
<td>Pool Price (Weighted by Volume)</td>
<td>$/MWh</td>
<td>$47.56</td>
<td>$66.38</td>
<td>($18.82)</td>
<td>(28.4%)</td>
</tr>
</tbody>
</table>

**Average Increase (Decrease) (Weighted by Revenue)**

(2.2%)
Additionally, Table 3-4 above provides a comparison of the forecast billing determinants in this tariff update to those in the AESO’s 2010 ISO tariff application. Coincident metered demand and energy billing determinants have decreased overall by less than 1% compared to the 2010 forecast, while number of DTS market participants has decreased by about 2.5%. Billing capacity (which incorporates non-coincident metered demand, demand ratchets, and contract minimums) has increased by about 1.3%, with decreases of up to 2% in the lower demand tiers and increases of up to 5% in the higher demand tiers. The AESO attributes the reduction in DTS market participants and the shift to higher tiers of billing capacity to the adjustments to the billing determinants forecast to reflect recent information on expected changes to specific individual services, as already discussed.

Overall, the AESO considers that the 2011 forecast provides an accurate estimation of billing determinants for the rate calculations in this application.

3.4 Bill Impacts

As noted in section 3.1 of this application, the AESO’s 2011 forecast costs represent an increase of 4.2% over the total costs for 2010 included in Appendix A of this application. From a bill impact perspective, however, it is more relevant to compare the 2011 forecast costs to the 2009 approved costs on which the AESO’s current rates are based. Table 3-5 below provides such a comparison.

<table>
<thead>
<tr>
<th>Cost Component</th>
<th>2011 Forecast $000,000</th>
<th>2009 Approved $000,000</th>
<th>Increase (Decrease) $000,000</th>
<th>%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wires</td>
<td>$786.2</td>
<td>$523.7</td>
<td>$262.5</td>
<td>50.1%</td>
</tr>
<tr>
<td>Ancillary Services</td>
<td>96.0</td>
<td>282.2</td>
<td>(186.3)</td>
<td>(66.0%)</td>
</tr>
<tr>
<td>Losses</td>
<td>121.0</td>
<td>238.0</td>
<td>(117.0)</td>
<td>(49.2%)</td>
</tr>
<tr>
<td>Administrative</td>
<td>83.0</td>
<td>80.0</td>
<td>3.1</td>
<td>3.8%</td>
</tr>
<tr>
<td>Revenue Requirement</td>
<td>$1,086.2</td>
<td>$1,123.9</td>
<td>($37.7)</td>
<td>(3.4%)</td>
</tr>
</tbody>
</table>

Note: Numbers may not add due to rounding.

The 2011 forecast costs represent a decrease of $37.7 million (4.0%) below the $1,213.9 million of total costs for 2009 as provided in the AESO’s 2009 rates update application. As summarized in Table 3-5 above, the net decrease results from markedly different changes to the different cost components that comprise the AESO’s revenue requirement:

- wires costs are forecast to increase by 50.1% reflecting recent approvals and applications for transmission facility owner tariffs,
- ancillary services costs are forecast to decrease by 66.0% reflecting primarily a forecast 45.3% decrease in pool price,
- losses costs are forecast to decrease by 49.2% also reflecting primarily a forecast 45.3% decrease in pool price, and
- administrative costs are forecast to increase slightly by 3.8%.
At the same time, billing determinants have also changed from the 2009 forecast on which currently-approved rates are based. As a result, the AESO’s 2011 tariff update represents an overall increase of 22.3% over the 2009 rates currently in place, including an increase of 27.6% to Demand Transmission Service Rate DTS and a decrease of 4.9% to Supply Transmission Service Rate STS.

As mentioned in section 3.1 of this application, deferral accounts provide certainty that the AESO’s costs will be exactly recovered by revenue, either through base rates or through deferral accounts. Increases in costs paid by the AESO will therefore flow to and impact customers through deferral accounts if rates are not increased. The changes in rates summarized above simply improve the timeliness and accompanying accuracy of the recovery of costs from customers.

The increases to the different components of Rate DTS are provided in Table 3-6 below. The Rate DTS increase of 27.6% represents an average increase over all components of Rate DTS. Individual increases experienced by market participants will vary, depending on the specific characteristics of a market participant’s service including peak demand coincidence, billing capacity, load factor, and hourly pool price at the time of usage.

<table>
<thead>
<tr>
<th>Rate DTS Charge</th>
<th>Proposed (1 Apr 2011)</th>
<th>Current (1 Oct 2009)</th>
<th>Increase (Decrease)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bulk System</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Coincident Demand</td>
<td>$3,313.00</td>
<td>$2,229.00</td>
<td>48.6%</td>
</tr>
<tr>
<td>• Energy</td>
<td>$1.17</td>
<td>$0.78</td>
<td>50.0%</td>
</tr>
<tr>
<td>Local System</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Billing Capacity</td>
<td>$972.00</td>
<td>$653.00</td>
<td>48.9%</td>
</tr>
<tr>
<td>• Energy</td>
<td>$0.49</td>
<td>$0.32</td>
<td>53.1%</td>
</tr>
<tr>
<td>Point of Delivery</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Participant × SF</td>
<td>$8,544.00</td>
<td>$7,030.00</td>
<td>21.5%</td>
</tr>
<tr>
<td>• First (7.5 × SF) MW BC</td>
<td>$5,788.00</td>
<td>$3,955.00</td>
<td>46.3%</td>
</tr>
<tr>
<td>• Next (9.5 × SF) MW BC</td>
<td>$2,136.00</td>
<td>$1,368.00</td>
<td>56.1%</td>
</tr>
<tr>
<td>• Next (23 × SF) MW BC</td>
<td>$1,294.00</td>
<td>$802.00</td>
<td>61.3%</td>
</tr>
<tr>
<td>• Remaining MW BC</td>
<td>$709.00</td>
<td>$425.00</td>
<td>66.8%</td>
</tr>
<tr>
<td>Operating Reserve</td>
<td>2.35%</td>
<td>4.82%</td>
<td>(51.2%)</td>
</tr>
<tr>
<td>Voltage Control</td>
<td>$0.51</td>
<td>$0.65</td>
<td>(21.5%)</td>
</tr>
<tr>
<td>Other System Support</td>
<td>$55.00</td>
<td>$62.00</td>
<td>(11.3%)</td>
</tr>
<tr>
<td>Net Change</td>
<td></td>
<td>27.6%</td>
<td></td>
</tr>
</tbody>
</table>
To allow individual market participants to estimate the impact of the 2011 rates on their own Rate DTS bills, the AESO has included a bill impact estimator as Table B5-14 in the rate calculations in Appendix B of this application. The bill impact estimator calculates bills for a given set of billing inputs under both the current 2009 rate and the proposed 2011 rate, to allow the impact of the rates update on an individual service to be estimated.

The decreases to the different components of Rate STS are provided in Table 3-7 below. The Rate STS decrease of 4.9% represents an average decrease over all components of the rate. Individual decreases or increases experienced by market participants will vary, depending on the specific characteristics of a market participant’s system access service including whether it includes a previously-regulated generating unit subject to the regulated generating unit (RGU) connection costs charge.

<table>
<thead>
<tr>
<th>Rate STS Charge</th>
<th>Proposed (1 Apr 2011)</th>
<th>Current (1 Oct 2009)</th>
<th>Increase (Decrease)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Losses % of Pool Price</td>
<td>4.46%</td>
<td>4.66%</td>
<td>(4.3%)</td>
</tr>
<tr>
<td>RGU Connection Costs $/MW</td>
<td>$236.00</td>
<td>$259.00</td>
<td>(8.9%)</td>
</tr>
<tr>
<td><strong>Net Change</strong></td>
<td></td>
<td></td>
<td><strong>4.9%</strong></td>
</tr>
</tbody>
</table>

In particular, the AESO notes that the loss factors provided in Table 3-7 are representative average loss factors only. The actual losses charge applicable to an individual market participant will be based on a location-specific loss factor determined in accordance with ISO rule 9.2, as specified in Rate STS.

### 3.5 2011 Maximum Investment Levels

The tariff update approach referred to in the extract from Decision 2010-606 at the beginning of section 3 in this application included updating investment amounts approved in the most recent comprehensive tariff application using the composite inflation index updated with any additional cost index values now available.

The AESO has accordingly updated the composite inflation index to 2011 using additional Statistics Canada cost index values and the most recent Conference Board of Canada forecast of the Alberta consumer price index for 2011. The 2011 composite inflation index, as well as the 2010 composite inflation index that was filed as part of the AESO’s 2010 ISO tariff application, are provided in Appendix C of this application.

The resulting escalation factor for updating the 2011 maximum investment levels in section 8 of the ISO tariff is 0.981, a small decrease relative to the 2010 maximum investment levels. The decrease reflects decreases in the latest underlying Statistics Canada indices used for the composite index in 2009, including:

- a 2009 increase of 1.24% for substation equipment in the 2011 index compared to a 2009 increase of 4.18% for the same category in the 2011 index,
• a 2009 decrease of 3.83% for transmission line material in the 2011 index compared to a 2009 decrease of 2.54% for the same category in the 2011 index, and
• a 2009 decrease of 3.20% for Alberta industrial services in the 2011 index compared to a 2009 increase of 1.89% for the same category in the 2011 index.

The net effect of these decreases together with other less-significant changes is a 2009 decrease of 5.54% in the 2011 index compared to a 2009 decrease of 3.10% in the 2010 index.

The decrease in the escalation factor also reflects the use of Statistics Canada 2010 values for the 2011 composite inflation index rather than the forecast 2010 Alberta consumer price index value used for the 2010 composite inflation index. The Statistics Canada 2010 values result in a 2010 increase of 1.17% in the 2011 index compared to a 2010 increase of 2.26% based on the forecast Alberta consumer price index.

A comparison of the 2011 composite inflation index and the 2010 composite inflation index is provided in Figure 3-8 below. The detailed calculation of both indices is included in Appendix C of this application.

Figure 3-8 Comparison of 2011 and 2010 Composite Inflation Indices
The AESO has applied the resulting 0.981 escalation factor to the 2010 Rate DTS maximum investment levels to determine the 2011 Rate DTS maximum investment levels, as summarized in Table 3-9 below. Table 3-9 also includes the calculation of the corresponding Rate PSC maximum investment levels for each year.

### Table 3-9 Calculation of 2011 Maximum Investment Levels

<table>
<thead>
<tr>
<th>Tier</th>
<th>Rate DTS Investment</th>
<th>PSC Factor</th>
<th>Rate PSC Investment</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>2010 Maximum Investment Levels</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Substation fraction (for new points of delivery only)</td>
<td>$51 050/year</td>
<td>21%</td>
<td>$10 720/year</td>
</tr>
<tr>
<td>First (7.5 × substation fraction) MW of contract capacity</td>
<td>$34 650/MW/year</td>
<td>21%</td>
<td>$7 275/MW/year</td>
</tr>
<tr>
<td>Next (9.5 × substation fraction) MW of contract capacity</td>
<td>$12 800/MW/year</td>
<td>21%</td>
<td>$2 690/MW/year</td>
</tr>
<tr>
<td>Next (23 × substation fraction) MW of contract capacity</td>
<td>$7 750/MW/year</td>
<td>21%</td>
<td>$1 630/MW/year</td>
</tr>
<tr>
<td>All remaining MW of contract capacity</td>
<td>$4 200/MW/year</td>
<td>0%</td>
<td>$0/MW/year</td>
</tr>
<tr>
<td><strong>2011 Investment Level Escalation Factor</strong></td>
<td></td>
<td></td>
<td>0.981</td>
</tr>
<tr>
<td><strong>2011 Maximum Investment Levels</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Substation fraction (for new points of delivery only)</td>
<td>$50 050/year</td>
<td>21%</td>
<td>$10 510/year</td>
</tr>
<tr>
<td>First (7.5 × substation fraction) MW of contract capacity</td>
<td>$34 000/MW/year</td>
<td>21%</td>
<td>$7 140/MW/year</td>
</tr>
<tr>
<td>Next (9.5 × substation fraction) MW of contract capacity</td>
<td>$12 550/MW/year</td>
<td>21%</td>
<td>$2 635/MW/year</td>
</tr>
<tr>
<td>Next (23 × substation fraction) MW of contract capacity</td>
<td>$7 600/MW/year</td>
<td>21%</td>
<td>$1 595/MW/year</td>
</tr>
<tr>
<td>All remaining MW of contract capacity</td>
<td>$4 100/MW/year</td>
<td>0%</td>
<td>$0/MW/year</td>
</tr>
</tbody>
</table>
4 Implementation

The AESO requests that the 2011 ISO tariff, as provided in Appendix E of this application, be approved to be effective April 1, 2011.

The AESO considers it has fully complied with all applicable directions in Decision 2010-606 and is currently preparing modifications to its billing system to issue bills for April 2011 in accordance with the rates and other provisions of the refiled tariff.

In the event the 2011 ISO tariff cannot be approved to be effective April 1, 2011, the AESO would appreciate being advised of the likely effective date as soon as practical, and will then adjust its implementation plans accordingly.

The AESO also requests that sections 8 and 9 of the 2010 ISO tariff, which is the construction contribution provisions in Appendix D of this application, be approved to be effective January 1, 2010 to March 31, 2011, inclusive. The AESO will determine the contribution changes that will apply to individual services are a result of the retroactive application of these provisions, and will communicate the changes to affected market participants as soon as practical after the contribution policy is approved.