



April 15, 2010

*Submitted via Commission Digital Data Submission (DDS) System*

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

Dear Sir or Madam:

**Re: AESO 2009 Deferral Account Reconciliation Application**

Please find enclosed the 2009 Deferral Account Reconciliation Application of the Alberta Electric System Operator (“AESO”). This application is made pursuant to sections 30 and 119 of the *Electric Utilities Act* (“Act”) under which the AESO prepares, submits, and receives approval from the Alberta Utilities Commission (“Commission”) for a tariff, having regard to section 14 of the Act which prescribes that “on an annual basis, no profit or loss results from its [the AESO’s] operation.”

This application includes a request for approval to collect and refund the customer amounts included in the application as soon as practical on an interim refundable basis, with such amounts subject to adjustment in final approvals following a full regulatory review, as described in section 10.1 of the application. Section 1.2 of the application discusses how interim settlement will fulfill the objectives of prompt and accurate settlement of the outstanding deferral account balances with customers. The AESO requests interim approval be granted by the end of May to allow settlement on invoices issued in June 2010.

This is a comprehensive application, and includes the determination and allocation to customers of a \$1.8 million net deferral account surplus, in respect of the following deferral account amounts (net of Rider C charges and refunds and any prior deferral account reconciliation settlements):

- a surplus of \$2.0 million from a first reconciliation of the deferral account for 2009,
- a shortfall of \$4.8 million from a second reconciliation of the deferral account for 2008,
- a surplus of \$3.4 million from a third reconciliation of the deferral account for 2007,
- a surplus of \$1.5 million from a third reconciliation of the deferral account for 2006,
- a shortfall of \$0.1 million from a third reconciliation of the deferral account for 2005, and
- a shortfall of \$0.3 million from a third reconciliation of the deferral account for 2004.

The AESO responds to certain outstanding directions and instructions of the Commission in this application, namely:

- recovery of \$35 million of costs paid to AltaLink for the cancelled Genesee-Langdon 500 kV project, as instructed in Decision 2009-151;
- inclusion of the balance of costs for the Keephills-Elleslie-Genesee unit transformers conversion, as directed in Decision 2009-191; and
- response to the Commission's concern about repeated reconciliations of deferral account years, as expressed in Decision 2009-191.

The application also includes several appendices providing details of calculations supporting the deferral account reconciliations and allocations to customers. As discussed in section 9.2 of the application, additional settlement point detail will be provided on request to customers, but is too extensive and detailed to be included with the application.

Technical meetings were held on the AESO's previous 2008 and 2004-2007 applications, and the AESO considers that the meetings provided a valuable opportunity for participants to more fully understand the information included in the application. The AESO therefore recommends a technical meeting also be held on the 2009 application. The AESO suggests such a meeting could be scheduled early in the week of May 10-14.

Based on the written reviews provided for the 2008 and 2004-2007 applications, the AESO suggests this application also be reviewed through a written proceeding.

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Yours truly,

*[original signed by]*

Heidi Kirrmaier  
Vice-President, Regulatory

cc: John Martin, Director, Tariff Applications, AESO  
Carol Moline, Director, Accounting & Treasury, AESO  
April Walters, Executive Assistant, Regulatory, AESO

**IN THE MATTER OF** the Alberta Electric System Operator (“AESO”) tariff and rates approved by the Alberta Utilities Commission pursuant to sections 14, 30, and 119 of the *Electric Utilities Act*, S.A. 2003, c. E-5.1.

**IN THE MATTER OF** an application for Alberta Utilities Commission approval of the AESO’s deferral account balance reconciliations for the calendar years 2009, 2008, 2007, 2006, 2005, and 2004.

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**Alberta Electric System Operator  
2009 Deferral Account Reconciliation  
Application**

**April 15, 2010**

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## 1 APPLICATION

1 This application is made pursuant to sections 30 and 119 of the *Electric Utilities Act* (“Act”), S.A. 2003, c. E-5.1, under which the Alberta Electric System Operator (“AESO”) prepares, submits, and receives approval from the Alberta Utilities Commission (“Commission”) for a tariff, having regard to section 14 of the Act which prescribes that “on an annual basis, no profit or loss results from its [the AESO’s] operation.”

2 The application seeks approval of the AESO’s:

- first reconciliation of deferral accounts for 2009;
- second reconciliation of deferral accounts for 2008; and
- third reconciliations of deferral accounts for 2007, 2006, 2005, and 2004.

3 The reconciliations for which approval is requested include the allocation, refund, and collection of reconciled variances arising between the actual costs the AESO has incurred in providing system access service and the forecast amounts recovered in rates charged to customers for those years.

### 1.1 Background

4 The AESO is a statutory, non-profit corporation established by section 7 of the Act and provides system access service to customers pursuant to the Act. Rates charged for service provided by the AESO are specified in the AESO’s tariff and are subject to regulation by the Commission under sections 30 and 119 of the Act.

5 The AESO’s tariffs which were in place from 2004 through 2009 were approved in various decisions and orders of the Commission (or its predecessor, the Alberta Energy and Utilities Board) as follows:

- Decision 2003-099 released on December 16, 2003 (amendments effective January 1, 2004);
- Order U2004-476 released on December 24, 2004 (tariff effective January 1, 2005);
- Order U2005-464 released on December 20, 2005 (tariff effective January 1, 2006);
- Order U2008-217 released on June 25, 2008 (tariff effective August 1, 2008); and
- Decision 2009-141 released on September 18, 2009 (tariff effective October 1, 2009).

6 Since January 1, 1997, the AESO’s approved tariffs (and those of its predecessors, ESBI Alberta Ltd. and Grid Company of Alberta) have included the use of deferral accounts. Deferral accounts are necessary to ensure no annual profit or loss results from the AESO’s operation in accordance with section 14 of the Act. Deferral accounts allow the AESO to address differences between actual revenues and costs incurred in providing system access service to customers, and are specifically provided for in subsections 122(2) and 122(3) of the Act.

7 Each of the tariffs in effect during the years addressed in this application included both:

- a Working Capital Deficiency/Surplus Rider B “to recover unexpected increases in the AESO’s working capital deficiency or to refund unexpected surpluses of working capital”

and “restore the AESO’s working capital deficiency to the AESO’s annual average forecast,” and

- a Deferral Account Adjustment Rider C “to recover or refund all accumulated deferral account balances” and “restore the deferral account balances to zero over the following calendar quarter or such longer period as determined by the AESO to minimize rate impact.”

8 These riders allow the AESO to manage its deferral account balances throughout the year. However, the AESO’s deferral accounts are also subject to later reconciliation, including approval of such reconciliation by the Commission. Under the deferral account methodology most recently approved by the Commission, the AESO reconciles, on a retrospective basis, the actual costs it has incurred in providing system access service to the revenues recovered in rates relating to provision of that service. For each reconciliation, costs and revenues are attributed to the time period during which the service was provided, which is referred to as reconciliation on a “production month” (or “production year”) basis.

9 The reconciliation of deferral account balances and the associated allocation of those balances to customers have previously been addressed:

- by the Alberta Energy and Utilities Board in Decision 2003-099 for 2000, 2001, and 2002 and Decision 2005-034 for 2003; and
- by the Commission in Decision 2009-010 for 2004, 2005, 2006, and 2007 and Decision 2009-141 for 2008.

10 In addition, the AESO formed a small stakeholder working group during 2009 to examine deferral account matters in consultation on its 2010 tariff application and also consulted with stakeholders in March 2010 specifically on the 2009 deferral account reconciliation. Stakeholders generally supported the proposals for the 2009 deferral account reconciliation as described and reflected in this application. As well, stakeholders did not indicate any concerns arising from the 2008 application and proceeding which would have required changes to the 2009 deferral account reconciliation and allocation.

11 The AESO therefore provides in this application the first reconciliation of 2009 deferral account balances; a second reconciliation of 2008 deferral account balances, and third reconciliations of 2007, 2006, 2005, and 2004 deferral account balances. The deferral account reconciliations have been prepared on a retrospective, monthly, and production month basis, consistent with the method used in the 2004-2007 and 2008 reconciliations as reviewed and approved by the Commission. More detailed discussion of the deferral account balances are provided in sections 3 (for 2009), 4 (for 2008), 5 (for 2007), 6 (for 2006), 7 (for 2005), and 8 (for 2004) of this application.

12 During 2009 no transactions occurred that related, either in whole or in part, to any year prior to 2004. Accordingly, no deferral account reconciliations or adjustments are included in this application for years prior to 2004.

13 The reconciliations included in this application take into account directions and instructions to the AESO contained in Commission decisions on the AESO’s 2008 deferral account reconciliation and other applications. In particular, this application includes the AESO’s

compliance with the direction in Decision 2009-191 to include the balance of the KEG transformer conversion project costs in the AESO's next deferral account reconciliation application. This application also includes the recovery of \$35 million of costs incurred for the cancelled Genesee-Langdon 500 kV project, which were paid to AltaLink by the AESO in accordance with the Commission's direction to AltaLink in Decision 2009-151. As well, the AESO responds in this application to concerns about repeated reconciliations of deferral account years expressed by the Commission in Decision 2009-191, as the AESO had promised to do in the initial response provided in its 2010 tariff application. Information on the AESO's compliance with the Commission's directions and instructions is provided in section 11 of this application.

- 14 Details on the deferral account balances and their allocation to customers for 2009, 2008, 2007, 2006, 2005, and 2004 are provided in the included appendices.
- 15 The deferral account reconciliations and allocations to customers provided in the body and appendices of this application have been prepared using a software program developed by the AESO specifically for this purpose. The program had also been used to prepare the AESO's 2004-2007 and 2008 deferral account reconciliation applications, and this application follows the same methodology as the previous applications which has been reviewed and approved by the Commission.

## 1.2 Immediate Interim Settlement With Customers

- 16 When the AESO filed its 2008 deferral account reconciliation application on April 9, 2009, it also requested interim approval to immediately settle deferral account amounts with customers. The purpose of requesting the immediate settlement was to collect from customers the outstanding deferral account shortfall to the greatest extent possible without further delay. The Commission approved the interim settlement of deferral account balances in Decision 2009-074 released on June 3, 2009.
- 17 The AESO similarly requests interim approval to immediately settle the current deferral account amounts with customers. The AESO notes that such settlement would be interim and refundable, and subject to adjustment in the final decision on the 2009 application following a full regulatory review.
- 18 The deferral account balances in this application are of similar magnitude to those in the 2008 application, and represent a net surplus to be refunded to customers rather than a net shortfall to be collected as in the 2008 application. Stakeholders were supportive of interim approval to immediately settle the deferral accounts in the consultation process held by the AESO in March 2010 and discussed briefly in section 1.1 above.
- 19 The deferral account balances in this application have been determined based on recorded costs paid and recorded revenues received by the AESO, and have been reconciled to the AESO's financial statements in the appendices. The AESO considers that the \$1.8 million net surplus balance reconciled in this application represents a probable and material amount, and this is one reason it is appropriate to request interim approval.

- 20 The allocation of deferral account balances to customers has been prepared in this application using the same methodology, and the same software program, as in the 2008 deferral account reconciliation application. The allocation in that application was approved as filed, and the AESO expects that the allocation in this 2009 application will also be found to be reasonable. Settlement with customers through interim distribution of the deferral account balances should therefore result in rate stability and intergenerational equity, and this is another reason interim approval is appropriate.
- 21 Based on the above, immediate interim settlement will provide prompt and accurate settlement of the outstanding deferral account balances with customers, and, in the AESO's view, is likely to render reasonable results in the immediate and longer term. The AESO has accordingly included a request for approval of immediate interim settlement of deferral account balances with customers in the relief requested in section 1.4 below.
- 22 The AESO understands from prior deferral account reconciliation proceedings that it is customary to seek the views of participants on a request for interim approval. The AESO suggests such an opportunity could be provided when participants submit statements of intent to participate ("SIPs"). If no party opposes interim settlement in its SIP, settlement of the deferral account balances could potentially be approved on an interim, refundable basis earlier than with a separate submission process.
- 23 If interim approval is issued before the end of May 2010, the AESO could financially settle amounts with customers in late June 2010, which would further enhance rate stability and intergenerational equity as discussed above. Interim approval is further discussed in section 10.1 of this application.

### 1.3 Organization of This Application

- 24 This application is organized into the following sections:
- 25 **1 Application** — Provides background on the application and specifies the relief requested.
- 26 **2 Summary of Deferral Account Reconciliation Process** — Summarizes the process used to determine deferral account amounts and other considerations affecting the deferral account reconciliation process.
- 27 **3 2009 Financial Results and Deferral Account Balance** — Discusses cost and revenue variances for 2009 and provides the deferral account balances for 2009.
- 28 **4 2008 Financial Results and Deferral Account Balance** — Discusses adjustments to costs and revenues that occurred after the first 2008 deferral account reconciliation and provides the outstanding deferral account balances for 2008.
- 29 **5 2007 Financial Results and Deferral Account Balance** — Discusses adjustments to costs and revenues that occurred after the second 2007 deferral account reconciliation and provides the outstanding deferral account balances for 2007.

- 30 **6 2006 Financial Results and Deferral Account Balance** — Discusses adjustments to costs and revenues that occurred after the second 2006 deferral account reconciliation and provides the outstanding deferral account balances for 2006.
- 31 **7 2005 Financial Results and Deferral Account Balance** — Discusses adjustments to costs and revenues that occurred after the second 2005 deferral account reconciliation and provides the outstanding deferral account balances for 2005.
- 32 **8 2004 Financial Results and Deferral Account Balance** — Discusses adjustments to costs and revenues that occurred after the second 2004 deferral account reconciliation and provides the outstanding deferral account balances for 2004.
- 33 **9 Allocation to Customers** — Discusses the process by which deferral account balances are allocated to customers.
- 34 **10 Proposed Method of Refunding and Collecting** — Discusses the proposed method of refunding and collecting deferral account amounts.
- 35 **11 Responses to Directions** — Provides responses to outstanding directions and instructions from Decision 2009-151 on AltaLink's and TransAlta's 2009 and 2010 transmission facility owner tariffs and Decisions 2009-191 on the AESO's 2008 deferral account reconciliation.
- 36 Appendices A through K provide additional detail in support of the application, including customer level allocation of deferral account balances.

#### 1.4 Relief Requested

- 37 This application follows the methodology approved in the AESO's 2004-2007 and 2008 deferral account reconciliation applications for reconciling deferral account balances and allocating those balances to customers. Furthermore, this application was prepared using the same software program developed for and used in the preparation of the 2004-2007 and 2008 applications. This application also addresses directions received from the Commission related to the AESO's deferral account reconciliations. Finally, no concerns with the methodology used by the AESO were identified by stakeholders in consultation held in preparation for this application.
- 38 The AESO therefore suggests this application be subject to approval through a written proceeding.
- 39 Based on the entirety of this application, and for the foregoing reasons, the AESO requests:
- 40 (a) Approval of the deferral account balance reconciliation calculations for the period January 1 to December 31, 2009 as described in section 3 of this application;
- 41 (b) Approval of the deferral account balance reconciliation calculations for the period January 1 to December 31, 2008 as described in section 4 of this application;

- 42 (c) Approval of the deferral account balance reconciliation calculations for the period January 1 to December 31, 2007 as described in section 5 of this application;
- 43 (d) Approval of the deferral account balance reconciliation calculations for the period January 1 to December 31, 2006 as described in section 6 of this application;
- 44 (e) Approval of the deferral account balance reconciliation calculations for the period January 1 to December 31, 2005 as described in section 7 of this application;
- 45 (f) Approval of the deferral account balance reconciliation calculations for the period January 1 to December 31, 2004 as described in section 8 of this application;
- 46 (g) Approval of the customer allocation methodology as presented in section 9 and Appendices G through K of this application, for purposes of recovering and refunding outstanding variance amounts from and to the AESO's DTS, FTS, and STS rate classes;
- 47 (h) Approval to collect and refund amounts through the use of a one-time payment/collection option similar to that used for previous years' deferral account balances as more particularly described in section 10 of this application;
- 48 (i) Approval to collect and refund the customer amounts included in this application as soon as practical on an interim refundable basis, with such amounts subject to adjustment in final approvals following a full regulatory review, as described in section 10 of this application;
- 49 (j) Approval of the continuation of annual retrospective reconciliations of adjustments to losses relating to years prior to 2006 (notwithstanding the implementation of prospective Rider E for losses in 2006 and later years);
- 50 (k) Approval to provide compliance reviews of second and later deferral account reconciliations included in the AESO's 2010 deferral account reconciliation application, and to financially settle deferral account balances in that application with customers as soon as practical after the compliance review is filed, as described in section 2.8 of this application;
- 51 (l) Confirmation by the Commission of its acceptance of the AESO's responses to outstanding directions provided in section 11; and
- 52 (m) Such further and other relief as the Commission may prescribe.



53 All of which is respectfully submitted this 15th day of April, 2010.

Alberta Electric System Operator

Per: \_\_\_\_\_  
Heidi Kirrmaier  
Vice-President, Regulatory

## 2 SUMMARY OF DEFERRAL ACCOUNT RECONCILIATION PROCESS

54 The deferral account reconciliation process used for this application reflects prior Commission decisions, as well as conclusions reached during stakeholder consultation on the AESO's prior deferral account reconciliation applications and the continued use of a software program to automate deferral account reconciliation calculations. In particular, the deferral account reconciliation process used for this application, as described below, is the same as that used for the AESO's 2008 deferral account reconciliation application.

### 2.1 Data Included in This Application

55 In addition to amounts settled in prior deferral account reconciliations for 2004 through 2008, this application incorporates all costs paid and revenues collected by the AESO that:

- have not been settled in prior deferral account reconciliation filings;
- relate to 2009 or prior years for all costs except those related to losses; and
- were accounted for up to December 31, 2009.

56 As discussed in more detail in section 2.1.2 below, effective January 1, 2006, transmission system losses are no longer subject to retrospective deferral account reconciliation as was the case for 2005 or prior years. There were no costs paid nor revenues collected by the AESO in 2009 related to losses for 2005 and prior years, and there are accordingly no deferral account balances for losses settled in this application.

57 Specifically, the following data is included for the different components of this application:

58 (a) **2009 First Reconciliation** — This application reconciles all costs paid and revenues collected by the AESO with respect to 2009, excluding costs and revenues related to losses, from January 1 to December 31, 2009. The reconciliation therefore includes all 2009-related costs and revenues settled during calendar year 2009, which result in a 2009 deferral account balance surplus of \$2.0 million.

59 (b) **2008 Second Reconciliation** — This application reconciles all costs paid and revenues collected by the AESO with respect to 2008, excluding costs and revenues related to losses, from January 1, 2008 to December 31, 2009. The AESO notes that its previous 2008 deferral account reconciliation application included all 2008-related costs and revenue, excluding costs and revenues related to losses, settled from January 1, 2008 to December 31, 2008. This current application incorporates all later adjustments (other than those relating to losses) for 2008 which occurred on or after January 1, 2009 and up to December 31, 2009, which result in a 2008 deferral account balance shortfall of \$4.8 million.

60 (c) **2007 Third Reconciliation** — This application reconciles all costs paid and revenues collected by the AESO with respect to 2007, excluding costs and revenues related to losses, from January 1, 2007 to December 31, 2009. The AESO notes that its previous 2008 deferral account reconciliation application included all 2007-related costs and revenue, excluding costs and revenues related to losses, settled from January 1, 2007 to December 31, 2008. This current application incorporates all later

adjustments (other than those relating to losses) for 2007 which occurred on or after January 1, 2009 and up to December 31, 2009, which result in a 2007 deferral account balance surplus of \$3.4 million.

- 61 (d) **2006 Third Reconciliation** — This application reconciles all costs paid and revenues collected by the AESO with respect to 2006, excluding costs and revenues related to losses, from January 1, 2006 to December 31, 2009. The AESO notes that its previous 2008 deferral account reconciliation application included all 2006-related costs and revenue, excluding costs and revenues related to losses, settled from January 1, 2006 to December 31, 2008. This current application incorporates all later adjustments (other than those relating to losses) for 2006 which occurred on or after January 1, 2009 and up to December 31, 2009, which result in a 2006 deferral account balance surplus of \$1.5 million.
- 62 (e) **2005 Third Reconciliation** — This application reconciles all costs paid and revenues collected by the AESO with respect to 2005, including those related to losses, from January 1, 2005 to December 31, 2009. The AESO notes that its previous 2008 deferral account reconciliation application included all 2005-related costs and revenue, including losses, settled from January 1, 2005 to December 31, 2008. This current application incorporates all later adjustments for 2005 which occurred on or after January 1, 2009 and up to December 31, 2009, which result in a 2005 deferral account balance shortfall of \$0.1 million.
- 63 (e) **2004 Third Reconciliation** — This application reconciles all costs paid and revenues collected by the AESO with respect to 2004, including those related to losses, from January 1, 2004 to December 31, 2009. The AESO notes that its previous 2008 deferral account reconciliation application included all 2004-related costs and revenue, including losses, settled from January 1, 2004 to December 31, 2009. This current application incorporates all later adjustments for 2004 which occurred on or after January 1, 2009 and up to December 31, 2009, which result in a 2004 deferral account balance shortfall of \$0.3 million.

### 2.1.1 Significant Prior Period Adjustments

- 64 This application includes some significant amounts that were accounted for in 2009 and attributed to periods prior to 2009 under the production month presentation used in this application. Those significant prior period adjustments include the following.
- 65 (a) a \$1.4 million net refund attributed to 2006, 2005, and 2004 wires costs resulting from settlement of AltaLink's transmission deferral accounts pursuant to Commission Decision 2008-076;
- 66 (b) a \$2.8 million charge attributed to 2008 and 2007 wires costs resulting from Commission Decision 2009-032 on the review of Decision 2007-071 on ATCO Electric's 2007-2008 general tariff application;
- 67 (c) a \$3.8 million refund attributed to 2008 and 2007 wires costs reflecting disposal of ATCO Electric's transmission deferral accounts and annual filing for adjustment

balances included in Commission Decision 2009-087 on ATCO Electric's 2009-2010 general tariff application;

- 68 (d) a \$1.2 million refund attributed to 2008 and 2007 wires costs resulting from Commission Decision 2009-199 on ATCO Electric's transmission deferral accounts and annual filing for adjustment balances;
- 69 (e) a \$1.2 million refund attributed to 2008 and 2007 wires costs resulting from Commission Decision 2009-031 on EPCOR's transmission deferral accounts;
- 70 (f) a \$0.5 million net refund attributed to 2008, 2007, 2006, 2005, and 2004 wires costs resulting from settlement of TransAlta's transmission deferral accounts included in Commission Decision 2009-151 on AltaLink's and TransAlta's 2009-2010 transmission facility owner tariffs;
- 71 (g) a \$2.2 million charge attributed to 2008 wires costs resulting from finalization of costs for the Keephills-Ellerslie-Genesee ("KEG") conversion of unit transformers in accordance with Commission Decision 2008-101 regarding AESO recovery of those costs (as discussed in more detail in section 4.2.1 of this application);
- 72 (h) a \$1.4 million charge attributed to 2008 ancillary services costs resulting from finalization of costs for unforeseeable TMR services under Article 11 of the AESO's tariff; and
- 73 (i) a \$1.0 million charge attributed to 2007, 2006, 2005, and 2004 ancillary services costs resulting from finalization of a review of costs for unforeseeable TMR services paid on an interim basis as far back as December 17, 2004 and adjusted under the pricing provisions approved in Commission Decision 2008-014 on the AESO's Ancillary Services Article 11 Negotiated Settlement.

### 2.1.2 Transmission System Losses

74 Effective January 1, 2006, transmission system losses are no longer subject to retrospective deferral account reconciliation as was the case for 2005 and prior years. As part of its 2006 general tariff application, the AESO applied for and received approval of calibration factor Rider E, which adjusts loss factors for the recovery of the actual costs of losses on a prospective basis in accordance with section 33(1) of the *Transmission Regulation*, AR 86/2007. The AESO has therefore not included reconciliation of losses amounts for the 2009, 2008, 2007, and 2006 deferral account years in this application.

75 Although transmission system losses have been subject to prospective Rider E since January 1, 2006, adjustments relating to years prior to 2006 have occurred since that date. Revenue and cost adjustments related to losses continue to be attributed to production months, and when the production month is prior to January 2006, adjustments are addressed through inclusion in an annual retrospective reconciliation application for the relevant year. When the production month is January 2006 or later, the adjustments have been or will be addressed through prospective Rider E.

76 The 2009 deferral account year is the first since 2005 in which there were no costs paid nor revenues collected by the AESO related to losses for 2005 or prior years. Accordingly, there are no variances with respect to losses costs or losses revenues included in the deferral account balances in this reconciliation application.

### 2.1.3 Adjustments Not Included

77 Any adjustments relating to 2009 or prior years which occurred after December 31, 2009 are not included in this application, and will be addressed in a future deferral account reconciliation application.

78 For example, Commission Decision 2010-054, on AltaLink's 2010 interim TFO tariff application, included interim approval of a \$5.4 million charge to the AESO for the month of January 2010. The charge resulted from a \$12.6 million revenue shortfall for 2009 offset by a \$7.2 million surplus arising from settlement of deferral accounts for the years 2006 through 2008. Although the \$5.4 million charge is attributable to 2009 and prior years, it was paid by the AESO after this application's data cut-off date of December 31, 2009, and will therefore be included in the AESO's 2010 deferral account reconciliation application expected to be filed in the second quarter of 2011.

79 Similarly, the AESO paid \$2.0 million of charges in January 2010 for foreseeable TMR services attributable to 2009 in accordance with the terms of existing contracts for those services. The payment occurred after this application's data cut-off date of December 31, 2009, and will therefore also be included in the AESO's 2010 deferral account reconciliation application.

80 The AESO also confirms that it has not included any redistribution of interest (as was proposed and disallowed in the AESO's 2004-2007 deferral account reconciliation application) with respect to deferral account balances in this application.

## 2.2 Production Month Presentation

81 In Decision 2005-034 on the AESO's 2003 Deferral Account Reconciliation, the Alberta Energy and Utilities Board noted:

*The primary distinction between production month and accounting month data relates to the manner in which billing adjustments are related to the AESO revenues attributed to specific customers in respect of specific months. Under the accounting month approach, adjustments on customer invoices relating to a prior period are attributed to the month in which the adjustment is applied to the customer's invoice. Conversely, under the production month method, invoice adjustment transactions are allocated back to the original month to which an adjusting transaction relates. [page 9]*

82 In the 2003 Deferral Account Reconciliation proceeding, the Board also ruled "that the AESO be required to provide deferral account reconciliation data derived on the basis of the production month data. In making its determination, the Board noted that use of production

month data would be more in keeping with the spirit of the Board's directions...in Decision 2003-099." (Decision 2005-034, page 10)

- 83 Consistent with this ruling, all revenues and costs included in this application for 2004 through 2009 are presented on a production month basis. For those years, adjustments to revenues or costs arising after the month to which an initial invoice pertains are attributed back to that original month, with two exceptions.
- 84 The first exception to the production month presentation of costs for 2004 through 2009 concerns the AESO's "own costs", which comprise other industry costs and general and administrative costs of the AESO. These costs by their nature are not attributable to specific matters of "production" and have simply been attributed to the month in which they occur. In effect, for "own costs", an accounting month basis is considered to be equivalent to a production month basis. The AESO notes that "own costs" account for 4% to 9% of the AESO's annual revenue requirements, and attempts to analyze and attribute such costs to specific production months would be expected to have insignificant effects on the final allocations to customers.
- 85 The second exception to the production month presentation of revenues for 2004 through 2009 is Rider C amounts, which are treated on an accounting month basis. Rider C amounts charge or refund forecast deferral account balances relating to the quarter in which the rider applies as well as accumulated balances from prior quarters. They typically charge or refund amounts relating to two or three quarters. However, in deferral account reconciliation applications, deferral account balances for each production month are recalculated based on recorded costs and recorded "base rate" revenue. Shortfalls and surpluses are allocated to customers, and Rider C amounts are then netted against these shortfalls and surpluses to determine final amounts to be refunded to or collected from each customer. Because of this recalculation of deferral account allocations, Rider C amounts result in the same net refunds or charges whether treated on a production month or accounting month basis.
- 86 The AESO notes that revenues, costs, and adjustments for some deferral account years prior to those included in this application (that is, for some years prior to 2004) were reconciled on an accounting rather than production basis, attributed to periods on an annual rather than monthly basis, and allocated in a year other than the deferral account year. However, all revenues, costs, and adjustments included in this application, for all years from 2004 through 2009, have been reconciled on a production basis, attributed to monthly periods, and allocated in the deferral account year. Those characteristics are summarized in Table 2-1 below.
- 87 The method of allocating the deferral account balances for each of these years to customers is discussed in detail in section 9 of this application.

*Table 2-1 Summary of Deferral Account Attribution Characteristics, 2004-2009*

Deferral Year	Reconciliation Basis	Adjustments Basis	Attribution Period	Allocation Year
2009	production <sup>1</sup>	— <sup>4</sup>	month	2009
2008	production <sup>2</sup>	— <sup>5</sup>	month	2008
2007	production <sup>3</sup>	— <sup>5</sup>	month	2007
2006	production <sup>3</sup>	— <sup>5</sup>	month	2006
2005	production <sup>3</sup>	— <sup>5</sup>	month	2005
2004	production <sup>3</sup>	— <sup>5</sup>	month	2004

Notes:

<sup>1</sup> 2009 first reconciliation is included in this application.

<sup>2</sup> 2008 second reconciliation is included in this application; 2008 first reconciliation was included in the AESO's application of April 9, 2009.

<sup>3</sup> 2007, 2006, 2005, and 2004 third reconciliations are included in this application; second and first reconciliations for those years were included in the AESO's applications of April 9, 2009 and June 2, 2008, respectively.

<sup>4</sup> The December 31, 2009 data cut-off date used for this application results in no prior-period adjustments being included for 2009.

<sup>5</sup> 2008, 2007, 2006, 2005, and 2004 adjustments are included in the full reconciliations for those years in this application.

### **2.3 Deferral Account Balances for 2004 to 2009**

88 Table 2-2 summarizes the deferral account balances and adjustments addressed in this application for deferral account years from 2004 to 2009.

89 Variances between revenues and costs, before any collections or refunds through Rider C or prior deferral account reconciliations, were:

- a shortfall of \$94.8 million or 12% of costs for 2009,
- a shortfall of \$142.9 million or 16% of costs for 2008,
- a shortfall of \$54.2 million or 7% of costs for 2007,
- a shortfall of \$0.2 million or 0.03% of costs for 2006,
- a shortfall of \$18.3 million or 2% of costs for 2005, and
- a surplus of \$66.6 million or 10% of costs for 2004.

90 The 2009, 2008, 2007, 2006, 2005, and 2004 deferral account variances were forecast on a quarterly basis and charged or refunded through Rider C during the relevant year or in the first quarter of the following year. As well, all years except 2009 have been subject to first deferral account reconciliations, and all except 2009 and 2008 to both first and second reconciliations, previously filed with and reviewed by the Commission. The initial variances between revenues and costs summarized above have been in large part addressed through Rider C and prior deferral account reconciliations, such that the net deferral account balances remaining which have not been included in prior reconciliations are:

- a surplus of \$2.0 million or 0.3% of costs for 2009,
- a shortfall of \$4.8 million or 0.5% of costs for 2008,
- a surplus of \$3.4 million or 0.5% of costs for 2007,
- a surplus of \$1.5 million or 0.2% of costs for 2006,
- a shortfall of \$0.1 million or 0.01% of costs for 2005, and
- a shortfall of \$0.3 million or 0.04% of costs for 2004.



*Table 2-2 Summary of 2009 Deferral Account Reconciliation Application, \$ 000 000*

	Deferral Account Reconciliations						Totals
	2009	2008	2007	2006	2005	2004	2004-2009
<b>Revenues</b>							
Interconnection	\$528.6	\$493.5	\$478.4	\$467.0	\$431.5	\$381.0	
Losses	-	-	-	-	180.7	138.4	
Operating Reserve	98.4	183.4	145.9	173.4	217.3	236.3	
Voltage Control	45.4	52.0	52.8	52.3	-	-	
Other System Support	7.9	8.2	8.0	7.9	2.4	2.2	
<b>Total Revenues</b>	<b>\$680.3</b>	<b>\$737.2</b>	<b>\$685.2</b>	<b>\$700.6</b>	<b>\$831.9</b>	<b>\$757.9</b>	<b>\$4,393.1</b>
<b>Costs Paid</b>							
Wires	(\$569.9)	(\$503.7)	(\$453.0)	(\$432.9)	(\$428.7)	(\$390.5)	
Ancillary Services	(132.8)	(313.6)	(237.2)	(233.0)	(189.8)	(124.0)	
Losses	-	-	-	-	(196.1)	(145.6)	
Other Industry	(14.2)	(11.5)	(4.8)	(3.6)	(5.3)	(5.0)	
General & Administrative	(58.2)	(51.3)	(44.3)	(31.4)	(30.3)	(26.3)	
<b>Total Costs Paid</b>	<b>(\$775.1)</b>	<b>(\$880.2)</b>	<b>(\$739.3)</b>	<b>(\$700.9)</b>	<b>(\$850.2)</b>	<b>(\$691.3)</b>	<b>(\$4,636.9)</b>
<b>Deferral Account</b>							
Surplus (Shortfall)	(\$94.8)	(\$142.9)	(\$54.2)	(\$0.2)	(\$18.3)	\$66.6	(\$243.8)
Rider C Collection (Refund)	96.8	133.5	58.1	15.1	18.7	(72.1)	250.1
Prior DAR <sup>1</sup> Collection (Refund)	-	4.6	(0.5)	(13.4)	(0.4)	5.2	(4.4)
<b>Net Surplus (Shortfall)</b>	<b>\$2.0</b>	<b>(\$4.8)</b>	<b>\$3.4</b>	<b>\$1.5</b>	<b>(\$0.1)</b>	<b>(\$0.3)</b>	<b>\$1.8</b>

Note: Numbers may not add due to rounding.

<sup>1</sup> DAR means Deferral Account Reconciliation.

- 91 Adjustments to revenues and costs also occur several (and sometimes many) months after the end of the calendar year to which the revenues and costs relate. Such adjustments arise for a variety of reasons, including:
- metered data adjustments, corrections, or restatements,
  - finalization of loss volumes,
  - Commission decisions on transmission facility owner (“TFO”) costs and other matters,
  - PFAM (Post Final Adjustment Mechanism) data restatements,
  - vendor invoice corrections,
  - revisions to contract terms, and
  - revisions to rate calculations or application.
- 92 Where adjustments relate to a calendar year prior to the year being reconciled in a deferral account reconciliation application, those adjustments are considered “prior period adjustments”. The prior period adjustments are attributed to the appropriate production months, as discussed in section 2.2 of this application. Prior period adjustments which related to 2008, 2007, 2006, 2005, and 2004 are included in the reconciliations for those years discussed above.
- 93 The net impact of the 2004-2009 deferral account reconciliation and re-reconciliations provided in this application is a net surplus of \$1.8 million, as provided in Table 2-2.
- 94 For comparison with Table 2-2, Table 2-3 provides a summary of comparable amounts as included in the AESO’s 2008 deferral account reconciliation application. In addition, Table 2-4 summarizes the differences between Tables 2-2 and 2-3, which reflects the net impact on deferral account balances of all revenue and cost transactions that have not been included in a prior deferral account reconciliation application.
- 95 The variances between revenues and costs included in Table 2-2 affect the deferral account balances to be collected from or refunded to customers. Adjustments to revenues received from individual customers also affect the allocation of the deferral account balances to those customers, since deferral account balances are allocated based on a customer’s revenue (or, for losses, on production volumes times pool price) when a deferral account is subject to full reconciliation as for 2009, 2008, 2007, 2006, 2005, and 2004.
- 96 The final allocations to individual customers are therefore dependent on both deferral account balances and individual customer revenues. The allocations to individual customers for 2009, 2008, 2007, 2006, 2005, and 2004 are provided in Appendices G, I, J, and K of this application.

## **2.4 Cost Prudency Considerations**

- 97 As discussed by the AESO in previous deferral account reconciliation proceedings, the AESO considers this application and related proceeding to be the proper venue in which to consider the prudence of AESO costs incurred with respect to 2009.



*Table 2-3 Summary of 2008 Deferral Account Reconciliation Application, \$ 000 000*

	Deferral Account Reconciliations						Totals
	2009	2008	2007	2006	2005	2004	2004-2008
<b>Revenues</b>							
Interconnection		\$494.3	\$478.7	\$467.0	\$431.5	\$381.0	
Losses		-	-	-	180.7	138.4	
Operating Reserve		183.5	145.9	173.5	217.3	236.3	
Voltage Control		52.1	52.8	52.3	-	-	
Other System Support		8.3	8.0	7.9	2.4	2.2	
<b>Total Revenues</b>		<b>\$738.1</b>	<b>\$685.5</b>	<b>\$700.6</b>	<b>\$831.9</b>	<b>\$757.9</b>	<b>\$3,713.9</b>
<b>Costs Paid</b>							
Wires		(\$501.1)	(\$457.2)	(\$434.3)	(\$428.7)	(\$390.5)	
Ancillary Services		(312.4)	(236.7)	(233.0)	(189.7)	(123.7)	
Losses		-	-	-	(196.1)	(145.6)	
Other Industry		(11.5)	(4.8)	(3.6)	(5.3)	(5.0)	
General & Administrative		(51.3)	(44.3)	(31.4)	(30.3)	(26.3)	
<b>Total Costs Paid</b>		<b>(\$876.3)</b>	<b>(\$743.0)</b>	<b>(\$702.3)</b>	<b>(\$850.1)</b>	<b>(\$691.0)</b>	<b>(\$3,862.8)</b>
<b>Deferral Account</b>							
Surplus (Shortfall)		(138.2)	(57.6)	(1.7)	(18.2)	66.9	(148.8)
Rider C Collection (Refund)		133.5	58.1	15.1	18.7	(72.1)	153.3
Prior DAR <sup>1</sup> Collection (Refund)		-	(2.0)	(11.3)	0.9	5.3	(7.0)
<b>Net Surplus (Shortfall)</b>		<b>(\$4.6)</b>	<b>(\$1.4)</b>	<b>\$2.0</b>	<b>\$1.4</b>	<b>\$0.1</b>	<b>(\$2.6)</b>

Note: Numbers may not add due to rounding.

<sup>1</sup> DAR means Deferral Account Reconciliation.



*Table 2-4 Summary of 2009 Net Deferral Account Transactions Since 2008 Deferral Account Reconciliation, \$ 000 000*

	Deferral Account Reconciliations						Totals
	2009	2008	2007	2006	2005	2004	2004-2009
<b>Revenues</b>							
Interconnection	\$528.6	(\$0.8)	(\$0.3)	\$0.0	-	-	
Losses	-	-	-	-	-	-	
Operating Reserve	98.4	(0.0)	(0.0)	(0.0)	-	-	
Voltage Control	45.4	(0.0)	0.0	0.0	-	-	
Other System Support	7.9	(0.0)	(0.0)	(0.0)	-	-	
<b>Total Revenues</b>	<b>\$680.3</b>	<b>(\$0.9)</b>	<b>(\$0.3)</b>	<b>\$0.0</b>	<b>-</b>	<b>-</b>	<b>\$679.1</b>
<b>Costs Paid</b>							
Wires	(\$569.9)	(\$2.6)	\$4.2	\$1.4	\$0.0	(\$0.0)	
Ancillary Services	(132.8)	(1.3)	(0.5)	0.1	(0.1)	(0.3)	
Losses	-	-	-	-	-	-	
Other Industry	(14.2)	-	0.0	-	-	-	
General & Administrative	(58.2)	-	-	-	-	-	
<b>Total Costs Paid</b>	<b>(\$775.1)</b>	<b>(\$3.9)</b>	<b>\$3.7</b>	<b>\$1.5</b>	<b>(\$0.1)</b>	<b>(\$0.3)</b>	<b>(\$774.2)</b>
<b>Deferral Account</b>							
Surplus (Shortfall)	(94.8)	(4.8)	3.4	1.5	(0.1)	(0.3)	(95.0)
Rider C Collection (Refund)	96.8	-	-	-	-	-	96.8
Prior DAR <sup>1</sup> Collection (Refund)	-	-	-	-	-	-	-
<b>Net Surplus (Shortfall)</b>	<b>\$2.0</b>	<b>(\$4.8)</b>	<b>\$3.4</b>	<b>\$1.5</b>	<b>(\$0.1)</b>	<b>(\$0.3)</b>	<b>\$1.8</b>

Note: Numbers may not add due to rounding.

<sup>1</sup> DAR means Deferral Account Reconciliation.

- 98 The AESO further notes, however, that ancillary services costs, losses costs, and administrative costs 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) and 48(1) of the *Transmission Regulation* also provide that ancillary services costs, losses costs, and administrative costs, once approved by the AESO Board, must be considered as “prudent” by the Commission unless an interested person satisfies the Commission otherwise.
- 99 As discussed in section 2.1.2 of this application, effective January 1, 2006, transmission system losses are no longer subject to retrospective deferral account reconciliation as is the case for 2005 and prior years. The reasonable recovery of the cost of transmission system losses is instead provided for in accordance with ISO Rule 9.2 and the requirements of the *Transmission Regulation*. Forecast and actual losses costs and revenues for 2009 are reported in the *Rider E Calibration Factor Calculations* provided in advance of each calendar quarter on the AESO website, and are not further discussed in this deferral account reconciliation application. The *Rider E Calibration Factor Calculations* are available on the AESO’s website at [www.aeso.ca](http://www.aeso.ca) by following the path Transmission ► Loss Factors ► Calibration Factors.
- 100 Where significant adjustments to 2008 or prior year costs are included in this deferral account reconciliation, this application and related proceeding are also the proper venue for consideration of the prudence of those adjustments to such costs. The AESO notes, however, that the prudence of AESO costs incurred with respect to 2008 and prior years which were already included in the AESO’s 2008 deferral account reconciliation application was considered in the 2008 and prior proceedings, and should not be reviewed again.
- 101 The presentation of a second reconciliation of the AESO’s 2008 deferral accounts, and of third reconciliations of the AESO’s 2004-2007 deferral accounts, in this application does not imply that all costs relating to those years are again subject to review. Rather, the second and third reconciliations are provided to appropriately allocate all costs related to those years to customers, not to re-examine the prudence of costs which have already been approved.
- 102 The AESO has accordingly provided schedules and explanations of significant variances by line item for 2009 and of significant adjustments to costs for 2008 and prior years where such adjustments have not previously been included in a deferral account reconciliation application, in sections 3, 4, 5, 6, 7, and 8 of this application.

## 2.5 Reconciliation to Financial Statements

- 103 The AESO’s annual reports include audited financial statements which present revenues and costs on a financial or accounting year basis (including accruals as noted in those statements) rather than on a production month basis as discussed in section 2.2 of this application. For example, the audited financial statements include or accrue revenues and costs which were known as of the end of the year being reported, whereas the deferral

account reconciliations in this application include production month revenues and costs which occur several (and sometimes many) months after year-end.

104 Therefore, revenues, costs, and deferral account balances included in this application have been reconciled to the revenues and costs reported in the AESO's audited income statements and balance sheets for 2009, 2008, 2007, 2006, 2005, and 2004. The reconciliations are provided in Appendices B and C of this application.

105 The AESO's annual report for 2009 is not yet available, although financial statements for 2009 have been audited and are provided in Appendix D-1. The AESO's annual reports for 2008, 2007, 2006, 2005, and 2004 (which include audited financial statements) are provided in the balance of Appendix D.

## 2.6 Review of Deferral Account Reconciliation Process

106 The AESO's deferral account reconciliation process includes controls to ensure complete and accurate deferral account reconciliations. The controls include:

- input controls such as reconciling data transferred to the deferral reporting system with source data and ensuring all values are assigned to production months; and
- process controls such as reconciling individual report totals to summary reports, manually testing and verifying the calculations embedded in the deferral reporting system, and reconciling balances to audited financial statements as provided in appendices B and C.

107 The AESO considers that the controls ensure the reliability of the deferral reporting system. In addition, the AESO conducts periodic rotational operating audits, reviews, and procedures to determine the existence and effectiveness of the internal controls as they relate to the AESO's operations and compliance with laws and regulations. Accordingly, in 2009 the AESO contracted PricewaterhouseCoopers ("PwC") to complete specified procedures to assess the accuracy of the data sorting and calculations performed in the deferral reporting system to determine and allocate deferral account balances to individual customers.

108 During consultation sessions related to the AESO's deferral account reconciliations, stakeholders generally supported such a review of the deferral reporting process due to the volume of data involved in a reconciliation, the number of calculations performed on the data, and the limited ability of market participants to assess and verify any aspects of the reconciliation beyond the calculations applicable to their individual accounts. Some stakeholders encouraged the AESO to discuss the results on the PwC engagement in this application.

109 The AESO has therefore included as Appendix A to this application a redacted version of the final report prepared by PwC on the results of the specified procedures performed on the AESO's 2008 deferral account reconciliation application filed with the Commission on April 9, 2009.. The report describes the nature and results of the specified procedures that were performed by PwC and used by the AESO to assess the deferral account reconciliation process. The specified procedures required PwC to independently recalculate components

of the 2005 through 2008 production year deferral amounts, allocate the associated balances to individual customers, and compare the PwC calculations with the AESO-reported values. The report is provided as appendix A to this application.

- 110 The purpose of the specified procedures was to assist the AESO in assessing the accuracy of:
- data sorting (from general ledger to deferral rule reporting), and
  - calculations performed to determine and allocate deferral account balances to individual customers.
- 111 The report includes the following conclusions:
- PwC did not note any differences between the production year costs aggregated by PwC and the AESO-published production costs for deferral purposes.
  - PwC did not note any differences between the PwC-summarized production revenue by category from the general ledger detail and the AESO-published production revenue by category for deferral purposes.
  - PwC did not note any differences between the general ledger revenue expected to be within the AESO's billing system and the PwC summarized billing revenue by category.
  - PwC did not note any discrepancies between the rules used by the AESO for rate class allocations for the in-scope production years and the allocations within the appropriate Commission-approved tariff.
  - For the production periods of January 2005 to December 2008 inclusive, PwC did not note any differences between the PwC-calculated and AESO-reported monthly deferral account balances.
  - For the production years of 2005-2008, PwC did not note any differences between the PwC-calculated and AESO-reported monthly customer deferral account balances.
  - For the production years of 2005-2008, PwC did not note any differences between the AESO's annual customer deferral account balances and annual customer deferral account balances in the filed deferral account reconciliation application.
- 112 The AESO considers that the PwC report supports and validates the accuracy of the deferral reporting system and related AESO processes.

## **2.7 Allocation to and Settlement With Customers**

- 113 This application provides detail on the allocation of deferral account balances to individual AESO customers, which requires the disclosure of transmission revenue received from individual customers. The application also includes the applied-for refunds to and collections from those individual customers.
- 114 Regulated distribution utilities will normally include their deferral account refunds and collections in their own tariff applications to the Commission and thereby make the deferral account amounts public. Those utilities — namely, ATCO Electric, ENMAX Power, EPCOR Distribution & Transmission, FortisAlberta, the City of Lethbridge, and the City of Red Deer — are therefore identified by name in the allocation tables in appendices of this application.

115 For AESO direct-connect customers, individual customer confidentiality is protected by assigning a number to each AESO direct-connected customer as has been done in prior deferral account reconciliation applications. The numbers assigned to a specific customer are not necessarily the same for each deferral account year in this application, and are not necessarily the same as those used in prior applications.

116 After filing this application, the AESO will distribute to each customer their applicable numbers for the deferral account reconciliation years included, as discussed in more detail in section 9.2 of this application.

## **2.8 Future Deferral Account Reconciliations**

117 In its 2008 deferral account reconciliation application, the AESO commented on its expectations for future deferral account applications. The AESO expected to:

- continue to use its deferral account reconciliation software program for future deferral account reconciliation applications;
- prepare future deferral account reconciliation applications based on initial settlement volumes and a December 31 data cut-off date;
- exclude year-end balances from the calculation of first quarter Rider C amounts;
- begin preparation of future deferral account reconciliation applications in February of each year; and
- consult with stakeholders on Riders B and C and on deferral account reconciliations in conjunction with preparations for the AESO's 2010 tariff application, and to potentially propose changes in the tariff application.

118 These expectations have generally been met. The deferral account reconciliation software program was used in the preparation of this application, which has been based on initial settlement volumes and a December 31, 2009, data cut-off date. The calculation of the 2010 first quarter Rider C excluded 2009 year-end balances, which allowed preparation of this application to begin in February 2010. The AESO expects to utilize the same approach in future deferral account reconciliations, and is not seeking any approval or direction on these matters for future deferral account reconciliations at this time.

119 The AESO also formed a small working group to examine deferral account Riders B and C in consultation on its 2010 tariff application, and proposed to discontinue Rider B and to modify some aspects of Rider C in that application (submitted to the Commission on March 5, 2010, as application 1605961 in proceeding ID 530). The AESO has requested approval of those changes to Riders B and C as part of the 2010 tariff application.

120 The AESO consulted on changes to simplify and improve the efficiency of the preparation and review of deferral account reconciliation applications both in the small working group during November 2009 and in more general consultation with stakeholders during March 2010 in preparation for this deferral account reconciliation application. In particular, the AESO discussed with stakeholders potential approaches to respond to the Commission's comments included in Decision 2009-191 on the AESO's 2008 deferral account reconciliation. In that Decision, the Commission stated (section 7, page 11, paragraph 57):

*Notwithstanding this finding, the Commission wishes to highlight its concern about the number of times that additional reconciliation is required in respect of deferral account years that have already been considered by the Commission in the context of prior deferral account reconciliation applications. The Commission urges AESO to be mindful of this concern as it considers its redesign of deferral account reconciliation processes and associated rate riders for its forthcoming GTA.*

- 121 The AESO first suggests that changes to deferral account reconciliation processes should be examined in a deferral account reconciliation application rather than in a tariff application. The AESO notes that previous deferral account process changes have been addressed in deferral account reconciliation rather than tariff applications. As well, the impact of deferral account process changes can be more fully explored in a deferral account reconciliation application, and changes proposed in a deferral account reconciliation application may potentially be implemented earlier than if proposed in a tariff application. For these reasons the AESO provides the following discussion in this deferral account reconciliation application rather than in its 2010 tariff application.
- 122 In considering the Commission's concern, the AESO first investigated changes to simplify and improve the efficiency of the deferral account reconciliation process. Based on its recent deferral account reconciliations, the AESO considered that it could be practical to provide full reconciliations for only the most recent three years in future deferral account reconciliation applications. For all earlier production years to which transactions apply, those transactions would be "rolled up" into the oldest year for which a full reconciliation was being completed. However, after further examination the AESO concluded that the "termination and roll-up" approach had several disadvantages, including:
- (a) reduction in the precision of the allocation of deferral account balances, especially for STS-related amounts;
  - (b) lack of transparency of the resulting allocation, especially if a terminated year had to be later re-reconciled;
  - (c) minimal reduction to AESO time and resource requirements, and possible increase if a terminated year had to be later re-reconciled; and
  - (d) significant risk that impacts on deferral account amounts allocated to customers would be materially affected and thus require re-reconciliation of a terminated year.
- 123 In light of these disadvantages, the AESO decided to continue to provide annual deferral account reconciliation applications that include full reconciliations of all production years to which transactions in the application year relate, since the methodology is well-established, the allocation is precise and transparent, and the regulatory review has generated little controversy in the AESO's most recent applications.
- 124 The AESO also considered other processes as alternatives to multiple full reconciliations, but concluded the implementation of an alternative process would be impractical while the

balances in the AESO's deferral accounts remain relatively large and volatile. However, the AESO has proposed three changes in its 2010 tariff application that may reduce the size and volatility of its deferral accounts:

- use of “reasonably expected” TFO wires costs for a forecast year's revenue requirement;
- hourly allocation of operating reserve costs; and
- annual updates of rate levels between comprehensive tariff applications.

- 125 The AESO considers that these changes will reduce the size and volatility of future deferral account balances after the 2010 tariff becomes effective, currently expected to be in early 2011. Until that time, however, deferral account balances may remain relatively large and volatile, requiring full retrospective reconciliations to provide precise and accurate allocation of those balances to customers.
- 126 The AESO has further considered the Commission's concern expressed in Decision 2009-191, and suggests there may be an opportunity to modify the review and approval process while continuing multi-year retrospective deferral account reconciliations. The relief requested in section 1.4 of this application, as in other recent deferral account reconciliation applications, relates primarily to approval of the calculations and allocation methodology used to assign deferral account balances to customers. When the calculations and allocation methodology have been approved for the initial reconciliation of a deferral account year, that same approach is used in all subsequent reconciliations of the same year.
- 127 The AESO investigated whether there may be a way to assure the Commission that a later reconciliation follows the originally-approved calculations and allocation methodology. Such assurance may remove the need for additional approvals for settling second and later reconciliation balances with customers. The AESO proposes that a formal compliance review completed by a third party could provide assurance that second and later reconciliations followed the calculations and allocation methodology approved for a first reconciliation. It may be prudent to rely on such a compliance review only when deferral account balances, both individually and in aggregate, are less than a specific materiality threshold. The AESO suggests that a reasonable threshold would be  $\pm 1\%$  of the AESO's annual revenue requirement subject to deferral account reconciliation, which is the threshold originally discussed with stakeholders as part of consultation for the AESO's 2004-2007 deferral account reconciliation.
- 128 The AESO suggests a compliance review approach primarily as an alternative to full regulatory reviews of second and later reconciliations after a first reconciliation has been approved for a deferral account year. In addition, the AESO expects it would be practical and efficient to include in the compliance review confirmation that the first reconciliation of a deferral account year follows the calculations and methodology described in the AESO's application and for which approval is requested. The compliance review would therefore cover all deferral account reconciliations included in an application, although Commission approval of each deferral account year's first reconciliation would still be requested to establish the approved calculations and allocation methodology for that year.

- 129 The AESO also suggests it would retain the right to request Commission approval of any specific deferral account re-reconciliation, where the AESO considers that unusual circumstances warrant such a request.
- 130 The AESO estimates that a compliance review of the calculations and allocation methodology for a deferral account reconciliation application would cost between \$100,000 and \$200,000 per year. This cost seems reasonable in the context of the significant time, effort, and expense involved in a full regulatory review of deferral account reconciliations. The cost of the compliance review would be included in the AESO's revenue requirement as an external regulatory cost in the other industry costs category, as the compliance review cost will reduce and replace regulatory proceeding costs which would otherwise be included in that category.
- 131 With respect to process, the AESO suggests it would file future deferral account reconciliations following the approach of this 2009 application, except with the body of the application containing only information related to the first reconciliation of the year for which the application is filed. Information on all prior-year second and later reconciliations would be located in appendices to the application. The AESO would engage a qualified third party who, immediately after the application was filed, would conduct a compliance review of all reconciliations included in the application. Upon completion of the review, the AESO would file the review with the Commission and, assuming no compliance concerns were identified, would immediately settle the deferral account balances with customers including settlement of first reconciliation deferral account balances on an interim basis. The remainder of the regulatory proceeding would then continue, leading to a final approval of the first reconciliation for the year of the deferral account reconciliation application.
- 132 The AESO submits that such a compliance review approach would remove the need for specific approval of second and later deferral account reconciliations. The AESO has accordingly included in section 1.4 of this application a request for approval to use the above approach for its 2010 deferral account reconciliation application.
- 133 Finally, the AESO also briefly discussed with stakeholders the possibility of a negotiated settlement process for deferral account reconciliation applications. Although not necessarily opposed to such an approach, stakeholders were concerned that they could only assess the accuracy of the calculations and the allocation methodology with respect to their own system access service accounts. No individual customer could examine the overall reasonableness of the deferral account reconciliation application due to confidentiality of account information for other customers. The AESO understands that stakeholders were accordingly reluctant to engage in a negotiated settlement process when visibility of all information was restricted in such a manner.
- 134 In conclusion, and as provided in section 1.4 of this application, the AESO requests approval to:
- (1) continue to provide annual deferral account reconciliation applications that include full reconciliations of all production years to which transactions in the application year relate;

- (2) provide compliance reviews of second and later deferral account reconciliations that remove the need for Commission approval of those reconciliations when deferral account balances, both individually and in aggregate, are less than  $\pm 1\%$  of the AESO's annual revenue requirement subject to deferral account reconciliation and when no unusual circumstances warrant a request for specific Commission approval of a second or later reconciliation; and
- (3) financially settle the first reconciliation as well as second and later reconciliations on a interim basis without specific Commission approval, upon filing of the compliance review for a deferral account reconciliation application.

### 3 2009 FINANCIAL RESULTS AND DEFERRAL ACCOUNT BALANCE

- 135 The AESO's 2009 costs and revenues which are subject to retrospective deferral account reconciliation in this application are those related to wires, ancillary services, and the AESO's own administration (which includes other industry costs and general and administrative costs).
- 136 As discussed in section 2.1.2 of this application, effective January 1, 2006, transmission system losses are no longer subject to retrospective reconciliation. Since that time, Calibration Factor Rider E has adjusted loss factors for the recovery of the actual costs of losses on a prospective basis in accordance with section 33(1) of the *Transmission Regulation*. Therefore, the financial results and deferral account balance for 2009 discussed in this section do not include costs and revenues related to losses.
- 137 In determining the financial results and deferral account balance for 2009, all revenue and cost transactions (except those related to losses) that occurred from January 1, 2009, to December 31, 2009 and that relate to 2009 have been included in the reconciliations. These transactions establish the 2009 production month data for deferral account reconciliation purposes in this application. The net result of these transactions is \$775.1 million in costs and \$777.1 million in customer revenues (including Rider C collections and refunds) being attributed to 2009. The difference between costs and revenues is a surplus of \$2.0 million, which is the net deferral account balance for 2009.
- 138 The AESO notes that revenue and cost transactions that occurred from January 1, 2009, to December 31, 2009 may also relate, in whole or in part, to years prior to 2009. In such instances, the transaction (or part of the transaction) which relates to a prior year has been assigned to the prior year, in accordance with the production month presentation described in section 2.2 of this application. Detail on the assignment between 2009 and prior years for transactions which occurred in 2009 is provided in Appendix E-1 of this application.

#### 3.1 2009 Cost Variances

- 139 The AESO's 2009 revenue requirement subject to retrospective reconciliation includes costs which have been approved either by the Commission (for TFOs) or by the AESO Board (for ancillary services and the AESO's own administration).
- 140 The TFO costs included in the AESO's 2009 revenue requirement were based on the tariff most recently approved by the Commission (on either a final or interim basis) for each TFO at the time the AESO filed its 2009 rates update application on March 12, 2009. Some of the TFO tariffs reflect Commission approvals for years prior to 2009, as those were the most recent years for which final or interim TFO tariff approvals had been issued at that time.
- 141 The ancillary services and administration costs included in the AESO's 2009 revenue requirement are those 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 customers 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.

- 142 The practice established by the AESO to carry out consultation on ancillary services, losses, and administrative costs is the Budget Review Process (“BRP”). The BRP is a transparent stakeholder process which provides a prudence review with input from stakeholders. At the conclusion of the BRP, a recommendation with respect to the ancillary services costs, losses costs, and administrative costs is provided by AESO management to the AESO Board for approval.
- 143 As part of the AESO BRP for its 2008 and 2009 budgets, AESO management consulted with stakeholders on a multi-year budget process. An abbreviated BRP was also developed in recognition of the need for a process to amend the approved multi-year budgets and to approve annual forecasts of ancillary services and losses costs.
- 144 AESO management, following consultation with stakeholders and incorporating appropriate amendments arising from the consultation, submitted an AESO Board Decision Document to the AESO Board on September 29, 2008. The Board Decision Document contained detailed proposals for amendments to the AESO’s 2008-2009 business plan and budget as it related to forecasted ancillary services costs, forecasted losses costs, and the AESO’s business priorities and budget for 2009. The document was also provided to stakeholders and posted on the AESO website. The final AESO Board Decision dated January 27, 2009, includes amendments to the forecasted ancillary services and losses costs for 2009 and to the AESO’s business priorities and budget for 2009. A subsequent AESO Board Decision dated December 17, 2009, includes additional revisions to the 2009 capital budget amount.
- 145 Additional information on the AESO’s business priorities and budget for 2009 is available on the AESO website at [www.aeso.ca](http://www.aeso.ca) by following the path About AESO ► Our Business ► Business Plan and Budget ► 2009 Budget Review.
- 146 Table 3-1 presents the AESO’s 2009 revenue requirement (excluding losses) as approved by the Commission (for TFOs) and by the AESO Board (for ancillary services and the AESO’s own administration) as discussed above. Table 3-1 also includes recorded costs as incurred for 2009, and variances between approved and recorded costs in both dollar amounts and as a percentage of approved costs.
- 147 Total 2009 recorded costs are \$110.8 million (or 13%) lower than the total 2009 approved revenue requirement. This variance consists of 2009 recorded costs being:
- \$46.2 million (or 9%) higher than the 2009 approved revenue requirement for wires,
  - \$149.5 million (or 53%) lower for ancillary services,
  - \$4.4 million (or 23%) lower for other industry costs, and
  - \$3.2 million (or 5%) lower for general and administrative costs.

Table 3-1 2009 Revenue Requirement and Recorded Costs (Excluding Losses), \$ 000 000

Line No.	Approved Forecast (a)	Recorded Costs (b)	Variance Over (Under)		
			\$ (c)=(b)-(a)	% (d)=(c)÷(a)	
<b>WIRES</b>					
<b>TFO Wires-Related Costs</b>					
1	AltaLink	235.6	270.6	35.0	14.9%
2	ATCO Electric	194.0	194.0	-	-
3	Isolated Generation	(9.3)	(3.3)	6.0	(64.9%)
4	Subtotal ATCO Costs	184.7	190.7	6.0	3.3%
5	ENMAX Power Corporation	31.9	36.5	4.6	14.5%
6	EPCOR Distribution & Transmission	51.7	51.7	0.0	0.1%
7	City of Lethbridge	4.5	4.5	-	-
8	TransAlta Utilities Corporation	4.2	4.2	-	-
9	City of Red Deer	1.7	1.7	-	-
10	FortisAlberta (Farm Transmission)	1.9	1.9	-	-
11	<b>Subtotal TFO Wires-Related Costs</b>	<b>516.2</b>	<b>561.9</b>	<b>45.7</b>	<b>8.9%</b>
<b>Non-Wires Costs</b>					
12	Invitation to Bid on Credits (IBOC)	1.6	1.6	0.0	1.4%
13	Location Based Credit Standing Offer (LBC SO)	5.9	6.4	0.5	8.4%
14	<b>Subtotal IBOC/LBC SO Costs</b>	<b>7.5</b>	<b>8.0</b>	<b>0.5</b>	<b>6.9%</b>
15	<b>TOTAL WIRES COSTS</b>	<b>523.7</b>	<b>569.9</b>	<b>46.2</b>	<b>8.8%</b>
<b>ANCILLARY SERVICES</b>					
<b>Operating Reserves</b>					
Active					
16	Regulating	59.1	32.2	(26.9)	(45.5%)
17	Spinning	86.9	36.7	(50.2)	(57.8%)
18	Supplemental	77.7	25.1	(52.6)	(67.7%)
19	<b>Subtotal Active Reserves</b>	<b>223.7</b>	<b>94.0</b>	<b>(129.7)</b>	<b>(58.0%)</b>
Standby					
20	Regulating	6.2	5.3	(0.9)	(14.1%)
21	Spinning	4.1	3.3	(0.8)	(19.3%)
22	Supplemental	1.6	0.9	(0.6)	(40.3%)
23	<b>Subtotal Standby Reserves</b>	<b>11.8</b>	<b>9.5</b>	<b>(2.3)</b>	<b>(19.4%)</b>
24	Trading Fees & Other Related Charges	-	(1.5)	(1.5)	-
25	<b>Subtotal Operating Reserves</b>	<b>235.5</b>	<b>102.1</b>	<b>(133.4)</b>	<b>(56.7%)</b>
<b>Other Ancillary Services</b>					
26	Brazeau Fast Ramp (Previously GRAS)	-	-	-	-
27	Black Start	2.9	1.6	(1.3)	(44.2%)
28	Transmission Must Run (TMR)	37.2	24.3	(12.9)	(34.7%)
29	Under Frequency Mitigation	4.5	2.7	(1.8)	(40.1%)
30	<b>Subtotal Other Ancillary Services</b>	<b>44.7</b>	<b>28.7</b>	<b>(16.0)</b>	<b>(35.9%)</b>

Table 3-1 2009 Revenue Requirement and Recorded Costs (Excluding Losses), \$ 000 000 (cont'd)

Line No.	Approved Forecast (a)	Recorded Costs (b)	Variance Over (Under)		
			\$ (c)=(b)-(a)	% (d)=(c)÷(a)	
<b>Poplar Hill/ILRAS</b>					
31	Poplar Hill	2.1	2.1	0.0	0.7%
32	Interruptible Load Remedial Action Scheme (ILRAS)	-	0.0	0.0	-
33	Generator Remedial Action Scheme (RAS)	-	-	-	-
34	<b>Subtotal Poplar Hill/ILRAS</b>	<b>2.1</b>	<b>2.1</b>	<b>0.0</b>	<b>0.7%</b>
35	<b>TOTAL ANCILLARY SERVICES</b>	<b>282.2</b>	<b>132.8</b>	<b>(149.5)</b>	<b>(53.0%)</b>
<b>OTHER INDUSTRY COSTS</b>					
36	External Regulatory Costs	5.9	0.3	(5.6)	(95.2%)
37	Western Electricity Coordinating Council (WECC)	2.8	3.5	0.7	23.9%
38	Share of AUC Costs	9.9	10.5	0.6	5.6%
39	<b>TOTAL OTHER INDUSTRY COSTS</b>	<b>18.6</b>	<b>14.2</b>	<b>(4.4)</b>	<b>(23.4%)</b>
<b>GENERAL AND ADMINISTRATIVE COSTS</b>					
<b>Administrative Costs</b>					
40	Staff and Benefits	32.3	30.4	(1.9)	(5.8%)
41	Consultants	8.6	9.8	1.2	13.7%
42	Board Members Fees	0.6	0.4	(0.1)	(21.2%)
43	Travel and Training	1.7	1.5	(0.2)	(13.5%)
44	Legal	0.8	0.8	(0.1)	(6.2%)
45	Audits/Reviews	0.6	0.4	(0.2)	(41.3%)
46	Rent <sup>1</sup>	2.5	2.7	0.2	10.1%
47	Insurance	0.4	0.4	(0.0)	(11.1%)
48	Other Administrative Costs	2.3	2.9	0.6	25.2%
49	Telecomm and IT Maintenance	2.5	3.0	0.5	19.4%
50	Interconnection Fees (Offset)	-	-	-	-
51	<b>Total Administrative Costs</b>	<b>52.3</b>	<b>52.3</b>	<b>(0.1)</b>	<b>(0.1%)</b>
<b>General Costs</b>					
52	Interest	1.8	0.9	(0.9)	(50.1%)
53	Amortization and Depreciation	7.3	5.0	(2.3)	(31.0%)
54	<b>Total General Costs</b>	<b>9.1</b>	<b>5.9</b>	<b>(3.1)</b>	<b>(34.7%)</b>
55	<b>TOTAL GENERAL &amp; ADMIN COSTS</b>	<b>61.4</b>	<b>58.2</b>	<b>(3.2)</b>	<b>(5.2%)</b>
56	<b>TOTAL G&amp;A AND OTHER INDUSTRY COSTS</b>	<b>80.0</b>	<b>72.4</b>	<b>(7.6)</b>	<b>(9.5%)</b>
57	<b>TOTAL REVENUE REQUIREMENT</b>	<b>885.9</b>	<b>775.1</b>	<b>(110.8)</b>	<b>(12.5%)</b>

*Table 3-1 2009 Revenue Requirement and Recorded Costs (Excluding Losses), \$ 000 000 (cont'd)*

Line No.	Approved Forecast	Recorded Costs	Variance Over (Under)		
			\$	%	
	(a)	(b)	(c)=(b)-(a)	(d)=(c)÷(a)	
<b>CAPITAL</b>					
58	General Capital	6.9	6.0	(0.9)	(13.4%)
59	Energy Management System ("EMS")	-	5.9	5.9	-
60	Dispatch Tool Re-Architecture	1.7	2.4	0.7	44.0%
61	<b>Total Capital</b>	<b>8.6</b>	<b>14.3</b>	<b>5.7</b>	<b>66.4%</b>

Notes: Numbers may not add due to rounding.

Shaded numbers indicate significant variances which are discussed in the text.

<sup>1</sup> Amortization of Rent Free Period not included in 2009 Recorded Costs on Line 46.

148 Variances arise due to a number of factors, including finalization of TFO costs through Commission decisions, variances from forecast of volumes and pool price, delays and changes in AESO schedules and priorities, and generally expected differences between recorded and forecast costs. The AESO considers a line item variance to be significant when it exceeds  $\pm\$6.0$  million, which represents approximately 10% of the \$61.4 million general and administrative costs component of the AESO's revenue requirement. A line item variance smaller than  $\pm\$6.0$  million is also considered significant when it is both at least  $\pm\$0.6$  million and at least  $\pm 10\%$  of the approved line item amount. The  $\pm\$0.6$  million threshold represents approximately 1% of the \$61.4 million general and administrative costs component of the AESO's revenue requirement, while the AESO considers  $\pm 10\%$  to be a reasonable threshold below which specific variance explanations are not required.

149 Variances exceeding these thresholds are shaded in Table 3-1, with explanations provided by line number in the following discussion. Where variances were either less than  $\pm\$0.6$  million or less than  $\pm 10\%$  (except where such variance is  $\pm\$6.0$  million or greater) explanations are not provided, as such variances are small enough that specific variance explanations are not required.

### 3.1.1 Wires Costs

150 The AESO's 2009 wires costs forecast was based primarily on TFO costs approved at the time the AESO filed its 2009 rates update application on March 12, 2009. The specific decisions approving the wires cost for each TFO were as follows.

151 (a) **AltaLink** — The 2009 forecast TFO wires cost was from Commission Decision 2008-129 released on December 9, 2008, which approved AltaLink's interim 2009 transmission facility owner tariff.

152 (b) **ATCO Electric** — The 2009 forecast TFO wires cost was from Commission Decision 2008-134 released on December 19, 2008, which approved ATCO Electric's interim 2009 transmission facility owner tariff. The 2009 forecast isolated generation credit was based on the 2009 forecast fuel costs for isolated generation included in ATCO Electric's 2009-2010 general tariff application. (The isolated generation credit

forecast was erroneously described in the AESO's 2009 rates update application as being based on 2008 recorded volumes for isolated communities and the 2009 forecast pool price. Please see the explanation of the ATCO Electric isolated generation variance at Line 3 below for more information.)

- 153 (c) **ENMAX Power Corporation** — The 2009 forecast TFO wires cost was from Alberta Energy and Utilities Board Decision 2006-130 released on December 21, 2006, which approved the continuance on an interim basis of ENMAX's refiling of its 2006 transmission facility owner tariff.
- 154 (d) **EPCOR Distribution & Transmission** — The 2009 forecast TFO wires cost was from Commission Decision 2008-125 released on December 3, 2008, which approved EPCOR's 2007-2009 transmission facility owner tariff on a final basis.
- 155 (e) **City of Lethbridge** — The 2009 forecast TFO wires cost was from Commission Order U2008-377 released on December 11, 2008, which approved Lethbridge's interim 2009 transmission facility owner tariff.
- 156 (f) **TransAlta Utilities Corporation** — The 2009 forecast TFO wires cost was from Commission Order U2008-367 released on December 4, 2008, which approved TransAlta's interim 2009 transmission facility owner tariff.
- 157 (g) **City of Red Deer** — The 2009 forecast TFO wires cost was from Commission Order U2008-378 released on December 11, 2008, which approved Red Deer's interim 2009 transmission facility owner tariff.
- 158 (h) **FortisAlberta (Farm Transmission)** — The 2009 forecast cost was from the revenue requirement schedules approved in Commission Decision 2008-011 released on February 12, 2008, which approved FortisAlberta's 2008/2009 Phase I Distribution Tariff and Negotiated Settlement Agreement on a final basis.
- 159 The recorded 2009 wires costs were as billed by the TFOs to the AESO based on the final or interim 2009 tariffs approved for the TFOs or resulting from adjustments approved for the TFOs. The AESO notes that final approvals were not issued before the end of 2009 for the 2009 TFO tariffs of AltaLink, ATCO Electric, ENMAX, Lethbridge, TransAlta, and Red Deer. If the final TFO tariffs approved for those TFOs differ from the interim tariffs included in the 2009 wires costs in this deferral account reconciliation, the difference will be included in the next deferral account reconciliation application filed after the final tariff is approved.
- 160 The recorded wires costs for 2009 totalled \$569.9 million, which is \$46.2 million (or 9%) more than the 2009 approved forecast of \$523.7 million. The variance is primarily due to payment to AltaLink for recovery of costs incurred for the cancelled Genesee-Langdon 500 kV project, an inappropriately high forecast for the ATCO Electric isolated generation credit, and approval of ENMAX's interim 2009 TFO wires costs.

**Line 1 AltaLink**

- 161 The 2009 recorded cost for AltaLink wires was \$270.6 million, which is \$35.0 million (or 15%) more than the 2009 approved forecast of \$235.6 million. The \$35.0 million increase results from the AESO's payment to AltaLink on December 31, 2009, for recovery of costs incurred for the cancelled Genesee-Langdon 500 kV project as directed by the Commission in its ruling released on December 24, 2009. The recovery of costs for the project was originally addressed in Commission Decision 2009-151 released on October 2, 2009, on AltaLink's 2009-2010 TFO tariff, where AltaLink was directed to give effect to a \$35 million "backstop" arrangement with the AESO.
- 162 On December 2, 2009, the AESO filed an application to review and vary certain elements of Decision 2009-151, including the Commission's finding with respect to the backstop arrangement between AltaLink and the AESO. On April 6, 2010, in Decision 2010-147, the Commission dismissed the AESO's request to review the backstop arrangement determination and confirmed that the Commission's original determination was consistent with and supported by the evidence given at the hearing on AltaLink's 2009-2010 TFO tariff.
- 163 In its original determination in Decision 2009-151, the Commission directed "AltaLink to give effect to the \$35 million backstop arrangement as soon as possible" (section 8.3, page 92, paragraph 529). AltaLink accordingly invoiced the AESO for the \$35 million payment, which the AESO paid on December 31, 2009, as noted above.
- 164 AltaLink included the costs incurred for the cancelled Genesee-Langdon 500 kV project as part of its 2009 revenue requirement in its December 23, 2009, refiling of its 2009-2010 transmission tariff pursuant to Decision 2009-151. The refiling also included the AESO's \$35 million payment (as invoiced but not yet paid at that time) as a reduction to AltaLink's 2009 revenue requirement, with a resultant 2009 interim tariff shortfall that AltaLink proposed to collect from the AESO as a single amount in January 2010. The Commission issued Decision 2010-054 on January 27, 2010, approving the collection in January 2010, on an interim and refundable basis, of the 2009 revenue requirement shortfall as calculated by AltaLink.
- 165 The AESO notes that the \$35 million amount was paid by the AESO to AltaLink in 2009, consistent with the direction from the Commission in its October 2009 decision that the payment be given effect "as soon as possible." The costs incurred for the cancelled Genesee-Langdon 500 kV project was included by AltaLink in its refiled 2009 revenue requirement, which also considered the payment by the AESO as a reduction to that 2009 revenue requirement. The 2009 net revenue requirement shortfall determined on that basis subsequently received interim approval in Commission Decision 2010-054. For all these reasons, the AESO considers the \$35 amount to be a 2009 production year expense attributable to AltaLink wires cost.
- 166 In Decision 2009-151, the Commission also expected "that AESO will address alternatives for funding the execution of this backstop arrangement either within an upcoming GTA or through a separate application to the Commission." As the \$35 million amount is a 2009 production year expense as discussed above, it could not readily be addressed in the AESO's 2010 ISO tariff application. The AESO has instead included it in this 2009 deferral

account reconciliation, which the AESO considers a more appropriate and efficient approach than a separate application.

**Line 3 ATCO Electric Isolated Generation**

167 In accordance with the *Isolated Generating Units and Customer Choice Regulation*, AR 165/2003, the isolated generation credit reflects payments from retailers to the AESO based on pool price for the energy used in communities served by isolated generation. The 2009 recorded isolated generation credit was \$3.3 million, which is \$6.0 million (or 65%) less than the 2009 approved forecast credit of \$9.3 million.

168 In investigating this variance, the AESO determined the 2009 forecast isolated generation credit was based on the 2009 forecast fuel costs for isolated generation included in ATCO Electric's 2009-2010 general tariff application. However, the forecast fuel costs are not necessarily reflective of pool price for the energy used in communities served by isolated generation. The 2009 forecast credit of \$9.3 million was also significantly higher than the 2008 recorded credit of \$6.7 million and the 2007 recorded credit of \$5.9 million noted in the AESO's 2008 deferral account reconciliation application. The AESO accordingly concludes that the 2009 forecast isolated generation credit was developed on an inappropriate basis and was thus inappropriately high.

169 The same inappropriate basis had also been used to develop the 2008 forecast isolated generation credit as had been explained in the AESO's 2008 deferral account reconciliation application (page 33, paragraph 144). The AESO had intended to use the correct basis of 2008 recorded volumes for isolated communities and 2009 forecast pool price for the 2009 forecast isolated generation credit, and had described that approach in its 2009 rates update application (page 13, lines 6-10). However, despite the description, the incorrect value was actually used in the 2009 forecast revenue requirement provided in that application.

170 The 2009 recorded credit of \$3.3 million is based on actual pool price during 2009 and was determined in accordance with the *Isolated Generating Units and Customer Choice Regulation*. The 2009 recorded credit is also lower than the recorded credits in previous years due to pool prices in 2009 being lower than pool prices in previous years.

**Line 5 ENMAX Power Corporation**

171 The 2009 recorded cost for ENMAX wires was \$36.5 million, which is \$4.6 million (or 15%) more than the 2009 approved forecast of \$31.9 million. The forecast cost was from Alberta Energy and Utilities Board Decision 2006-130 released on December 21, 2006, which approved the continuance on an interim basis of ENMAX's refiling of its 2006 transmission facility owner tariff. The recorded cost was from Commission Decision 2009-084 released on June 16, 2009, which approved ENMAX's 2009 transmission facility owner tariff (as included in ENMAX's 2007-2013 formula based ratemaking compliance application) on an interim basis.

**3.1.2 Ancillary Services**

172 The recorded ancillary service costs for 2009 totalled \$132.8 million, which is \$149.5 million (or 53%) less than the 2009 approved forecast of \$282.2 million. The primary component of this variance is a decrease in active operating reserves costs of \$129.7 million (or 58%) due

to significantly lower than forecast pool prices. The variance also includes a decrease in standby operating reserves costs, a credit arising from trading fees and other related charges, and reductions in the costs of black start service, transmission must-run service, and under frequency mitigation service (now referred to as load shed service (“LSS”)).

173 Explanations of the variances of the 2009 recorded costs from the 2009 approved forecast are provided in the sections that follow.

**Lines 16 to 25 Operating Reserves**

174 Operating reserves are unloaded megawatt capacity that is available to respond to temporary shortfalls in supply caused by the loss of a generating unit, intertie capabilities, or moment-to-moment fluctuations in the load. Operating reserves are comprised of regulating reserve and contingency reserves (including spinning and supplemental reserves).

175 Regulating reserve refers to the amount of synchronized generation that responds to automatic generation control (“AGC”) signals that track moment-to-moment fluctuations in the supply and demand. Regulating reserves track variations in load that cannot be met with energy dispatches. Because variations in supply and demand can be either positive or negative, regulating reserves have a range with an upper and lower limit. The volumes of regulating reserve are specified as a range in megawatts over which a level of control is required by the AGC system.

176 Spinning reserve is unloaded generation that is synchronized to the system, automatically responsive to deviations in frequency, and ready to serve additional demand following a System Controller directive within 10 minutes.

177 Supplemental reserve is unloaded generation, off-line generation, or system load that is ready to serve additional demand (generator) or to reduce demand (load) within 10 minutes of a directive from the System Controller.

178 Spinning and supplemental reserves are required in order to restore frequency following the loss of generation in Alberta or in the Western Electricity Coordinating Council (“WECC”) region. Alberta must comply with WECC policies for maintaining specific volumes of spinning and supplemental reserves in order to maintain reliability.

179 About 90% of operating reserves volumes is competitively procured through the Alberta Watt Exchange (“Watt-Ex”), an electronic exchange where transactions reflect bids of the AESO and offers from market participants. The remaining 10% of operating reserves volumes are procured directly from suppliers through over-the-counter (“OTC”) transactions facilitated by the AESO.

*Lines 16 to 18 Active Operating Reserves*

180 Active operating reserves are the operating reserves that are forecast by the AESO as necessary to operate the Alberta interconnected electric system (“AIES”) securely and meet the AESO’s reliability obligations to WECC. 2009 recorded costs were \$94.0 million, which is \$129.7 million (or 58%) less than the 2009 approved forecast of \$223.7 million, and comprised the following amounts:

- For active regulating reserve, the 2009 recorded cost was \$32.2 million, which is \$26.9 million (or 46%) less than the 2009 approved forecast of \$59.1 million.
- For active spinning reserve, the 2009 recorded cost was \$36.7 million, which is \$50.2 million (or 58%) less than the 2009 approved forecast of \$86.9 million.
- For active supplemental reserve, the 2009 recorded cost was \$25.1 million, which is \$52.6 million (or 68%) less than the 2009 approved forecast of \$77.7 million.

181 The recorded costs of all active operating reserves result from the competitive determination of prices through the operating reserves market. The operating reserve market is structured such that operating reserve prices are indexed to pool price, which means that active operating reserve costs are directly related to pool price. The decrease in 2009 recorded costs for active operating reserves compared to the approved forecast was due primarily to the significant reduction in recorded pool prices from forecast. The 2009 recorded average pool price was \$47.81/MWh, which is 43% less than the forecast average pool price of \$84.43/MWh upon which the operating reserve costs forecast was based. As well, larger discounts for operating reserves were observed during several months of 2009 relative to discounts for previous years upon which the forecast was based.

182 The decrease in 2009 recorded costs for active operating reserves also reflected a small decrease in recorded volumes compared to forecast. In total, 2009 recorded active operating reserves volumes were 5,659 GWh, which is 191 GWh (or 3%) less than the 2009 approved forecast of 5,850 GWh due to recorded demand being lower than forecast.

*Lines 20 to 23 Standby Operating Reserves*

183 Standby reserves are additional reserves that are available to the System Controller in the event an active provider fails to provide active reserves, or if actual requirements are higher than the active reserve forecast. Payments for standby reserves include a premium paid for the option to activate the standby reserves and a price that is paid if the reserves are activated.

184 For standby regulating reserves, the 2009 recorded cost was \$5.3 million, which is \$0.9 million (or 14%) less than the 2009 approved forecast of \$6.2 million.

185 For standby spinning reserves, the 2009 recorded cost was \$3.3 million, which is \$0.8 million (or 19%) less than the 2009 approved forecast of \$4.1 million.

186 For standby supplemental reserves, the 2009 recorded cost was \$0.9 million, which is \$0.6 million (or 40%) less than the 2009 approved forecast of \$1.6 million.

187 Standby reserves prices are determined by the various offer strategies of the numerous providers involved in the market at any given time. As with active reserves, the cost variances for standby reserves reflected 2009 recorded pool prices that were significantly lower than forecast.

188 Standby reserves volumes are quite small, and therefore particularly sensitive to unforecastable real-time conditions, including variances from load forecasts as well as

unplanned generation and transmission outages, which affect the availability of active reserves providers.

189 In total, 2009 recorded standby operating reserves volumes were generally consistent with the 2009 approved forecast. Standby premium volumes were 2,398 GWh which is 16 GWh (or 1%) less than the 2009 approved forecast of 2,414 GWh. Standby activation volumes were 59 GWh which is 26 GWh (or 31%) less than the 2009 approved forecast of 85 GWh.

*Line 24 Trading Fees and Other Related Charges*

190 The 2009 recorded cost for trading fees and other related charges was a credit of \$1.5 million. No corresponding amount was included in the approved forecast. The variance arose from unforecasted collections of non-compliance charges of \$2.2 million, offset by trading costs to Watt-Ex of \$0.7 million.

**Lines 26 to 34 Other Ancillary Services**

191 Other ancillary services include the remaining services that the AESO procures for the secure and reliable operation of the Alberta interconnected electric system. These services are normally procured through bilateral contract negotiations with one or more suppliers, and include black start, transmission must-run (“TMR”), under frequency mitigation (now referred to as load shed service), Poplar Hill, and interruptible load remedial action scheme (“ILRAS”) services.

192 The 2009 recorded cost of other ancillary services was \$30.7 million, which is \$16.0 million (or 34%) less than the 2009 approved forecast of \$46.7 million, due to pool and natural gas prices being significantly lower than forecast.

193 Black start service is provided by generators that are able to restart their generation facility with no outside source of power. In the event of a system-wide black-out, black start providers are called upon to re-energize the transmission system and provide start-up power to generators who can not self-start. The service is procured by the AESO through contracts with service providers. The 2009 recorded cost for black start service was \$1.6 million, which is \$1.3 million (or 44%) less than the 2009 approved forecast of \$2.9 million. The forecast amount included signing contracts with additional service providers during 2009, which did not materialize and resulted in recorded costs being lower than forecast.

194 Transmission must-run (TMR) services are used to ensure safe and reliable electrical service for a region of the interconnected electric system and are procured by the AESO through bilateral contracts. The determination of when to dispatch a generator to provide TMR service is based on local demand and local transmission constraints. Since TMR services are provided by gas-fired generators, the underlying costs of the services are dependent on the price of natural gas as well as on pool price. The 2009 recorded cost for TMR services was \$24.3 million, which was \$12.9 million (or 35%) less than the 2009 approved forecast of \$37.2 million due to recorded pool prices and natural gas prices both being significantly lower than forecast.

195 Under frequency mitigation (now referred to as load shed service) is configured to automatically trip a specific amount of load if the system frequency drops below 59.5 Hz

following a system disturbance. The service is procured by the AESO through contracts with service providers. The 2009 recorded cost for under frequency mitigation was \$2.7 million, which is \$1.8 million (or 40%) less than the 2009 approved forecast of \$4.5 million due to the withdrawal of one service provider during 2009.

196 The 2009 recorded costs for the remaining other ancillary services (Poplar Hill and ILRAS) did not vary significantly from the 2009 approved forecast.

### 3.1.3 Other Industry Costs

197 The 2009 recorded other industry costs were \$14.2 million, which is \$4.4 million (or 23%) less than the 2009 approved forecast of \$18.6 million, primarily due to lower recorded external regulatory costs offset by slightly higher Western Electricity Coordinating Council (“WECC”) fees.

#### Line 36 External Regulatory Costs

198 External regulatory costs include cost recovery amounts related to the AESO’s regulatory proceedings. The staff, legal, and consulting costs in the administrative costs section of the AESO’s revenue requirement do not include AESO recoverable regulatory costs.

199 The 2009 recorded external regulatory costs were \$0.3 million, which is \$5.6 million (95%) less than the 2009 approved forecast of \$5.9 million. In 2009, recorded external regulatory costs primarily represented the recoverable costs of the AESO and registered participants related to proceedings for the AESO’s southern Alberta transmission system reinforcement needs identification document application and the AESO’s 2004-2007 deferral account reconciliation application. The 2009 forecast amount had been based on the estimated cost recovery for several AESO proceedings which did not result in cost awards in 2009, including:

- the AESO’s 2010 tariff application which was filed in March 2010; and
- several needs identification document (“NID”) filings for transmission facilities, including a re-filing for the 500 kV north-south transmission reinforcement, a second 500 kV north-south transmission line, and a fourth transmission circuit to Fort McMurray, which are in various stages of planning and preparation.

#### Line 37 Western Electricity Coordinating Council (WECC)

200 The AESO is a member of WECC, the United States regional entity responsible for coordinating and promoting electricity system reliability in the western North American interconnected electric system. The WECC budget assessments to balancing authority areas is based on the ratio of each balancing authority area’s annual net energy for load to the total annual net energy for load for the western interconnection. The AESO pays the WECC funding portion assessed to the Alberta balancing authority area. The 2009 recorded costs for WECC membership were \$3.5 million, which is \$0.7 million (or 24%) more than the forecast of \$2.8 million due to a budget increase approved by the WECC board of directors and assessed to the Alberta balancing authority area as described above.

201 The 2009 recorded costs for the AESO’s share of Commission overhead did not vary significantly from the 2009 approved forecast.

### 3.1.4 General and Administrative Costs

202 The 2009 recorded general and administrative costs were \$58.2 million, which is \$3.2 million (or 5%) less than the 2009 approved forecast of \$61.4 million. This variance was primarily due to decreases in interest and amortization and depreciation, offset by increases in the cost of consulting and other administrative costs with smaller increases and decreases in other cost components.

#### Line 41 Consultants

203 Consultants are utilized by the AESO to assist in the completion of those tasks that require specialized skills that are neither resident in the AESO nor required by the AESO on an ongoing basis, and to address workload peaks. The 2009 recorded consulting costs were \$9.8 million, which is \$1.2 million (or 14%) more than the 2009 approved forecast of \$8.6 million. This variance is due to increases resulting from utilizing consulting services on the following areas in 2009:

- assistance in the preparation of connection proposals, including those for wind generation projects;
- implementation of an expanded public education program;
- stakeholder consultation on and drafting of AESO authoritative documents; and
- assistance in support of a corporate organization review.

#### Line 48 Other Administrative Costs

204 The 2009 recorded other administrative costs were \$2.9 million, which is \$0.6 million (or 25%) more than the 2009 approved forecast of \$2.3 million. This increase is primarily due to

- additional recruiting efforts related to new staff positions and replacements due to general attrition; and
- print and media communication costs, including an additional issue of the *Powering Albertans* publication, to educate Albertans about electricity matters such as issues that concern a safe and reliable interconnected electric system.

#### Line 52 Interest

205 Interest expense includes interest incurred by the AESO on bank debt held to provide working capital and to fund capital purchases, credit facility standby fees, and fees charged related to the letter of credit issued as security for operating reserve procurement.

206 The 2009 recorded interest cost was \$0.9 million, which is \$0.9 million (or 50%) less than the 2009 approved forecast of \$1.8 million primarily due to reductions to market interest rates due to economic events during 2009. The lower interest rates resulted in lower borrowing costs in 2009 compared to the forecast in the 2009 budget. As well, the AESO required lower borrowing amounts during 2009 as a result of working capital surpluses that occurred throughout the year.

**Line 53 Amortization and Depreciation**

207 The amortization and depreciation amount is determined on a straight-line basis over the following terms:

- three to five (3-5) years for office equipment and computer hardware,
- five to seven (5-7) years for computer software,
- seven (7) years for the new system coordination computer systems (usually referred to as the energy management system (“EMS”));
- ten (10) years for System Coordination Centre facility infrastructure,
- eighteen (18) years (ending in 2025) for the System Coordination Centre, and
- the lease term (ending in 2014) for leasehold improvements.

208 The 2009 recorded amortization and depreciation costs were \$5.0 million, which is \$2.3 million (or 31%) less than the 2009 approved forecast of \$7.3 million, primarily due to the majority of the purchasing or commissioning of assets (mainly the EMS) occurring in the last few months of the year rather than earlier in the year as anticipated.

209 The 2009 recorded costs for the remaining general and administrative components did not vary significantly from the 2009 approved forecast.

**3.1.5 Capital**

210 Capital investment is required by the AESO for the development of IT infrastructure necessary to support the transmission function, for its System Coordination Centre (“SCC”) facility and infrastructure, and for leasehold improvements, furniture, and equipment. Capital costs recorded in 2009 were \$14.3 million, which is \$5.7 million (or 66%) more than the 2009 approved forecast of \$8.6 million, primarily due to cost variances for the EMS project, with smaller variances for general IT infrastructure additions and the re-architecture of the dispatch tool.

211 The 2009 forecast transmission capital costs were \$5.3 million as approved in the AESO Board Decision dated January 27, 2009. That amount was included in the AESO’s 2009 rates update application. The 2009 forecast transmission capital costs were increased to \$8.6 million as approved in the AESO Board Decision dated December 17, 2009.

**Line 58 General Capital**

212 In the AESO Board Decision dated March 28, 2008, the allocation of general capital expenditures for transmission IT infrastructure was \$5.3 million for 2009. Subsequently, the AESO Board Decision dated December 17, 2009 approved a corporate capital expenditure increase of \$5.0 million. The decision included the following discussion:

*At the time the 2009 budget was reviewed by AESO Management and the AESO Board, the cost estimates were at an early stage of development and were not perfected. As project details and costs were developed and refined, it was determined that an additional \$5.0 million would be required to address the scope of work. [page 2]*

213 Management's allocation of the forecast increase assigned \$2.5 million to general capital and \$2.5 million to the Dispatch Tool Re-Architecture Project. In each case, the allocation for transmission costs was determined to be 67% of the \$2.5 million, or \$1.7 million, which increased the general capital budget to \$6.9 million for 2009.

214 General capital costs recorded in 2009 were \$6.0 million, which is \$0.9 million (or 13%) less than the 2009 approved forecast of \$6.9 million, primarily as a result of the slower than anticipated pace of capital infrastructure development and acquisition during 2009.

#### **Line 59 Energy Management System ("EMS")**

215 The EMS project is a major capital project to replace the AESO's current system in response to increasingly complex operational requirements, security for the operations of the interconnected electric system, and the age of the existing system. As part of this initiative, a new Enterprise Service Bus ("ESB") technology has been implemented that will enhance the flexibility and integration of EMS with other AESO IT operating systems, to ensure redundancy and high availability exists to support the system controllers who supervise and direct the operations of the power system. More stringent security and North American Electric Reliability Corporation ("NERC") standards will also require additional investment in the AESO's computer systems to provide disaster recovery capabilities. The initial release of the system was commissioned in November 2009 with additional releases continuing through 2010 and 2011.

216 The EMS project is a multi-year initiative first presented to stakeholders as part of the AESO's 2007 budget review process. Scope and budget changes were presented to stakeholders during 2008, with a final budget amendment of \$6.3 million approved by the AESO Board on March 25, 2009. The revised total budget amount for the EMS project is now \$20.7 million, including both capital and operating costs associated with the project. The budget amount was not assigned to specific years.

217 By the end of 2009, \$18.2 million in capital costs and \$0.6 million in operating costs had been incurred in accordance with the progress of the project. In 2009, \$8.8 million in capital costs and \$0.4 million in operating costs were incurred, in addition to those costs incurred in 2007 and 2008. Transmission customers were allocated 67% of the project costs, resulting in the \$5.9 million recorded in Table 3-1 above for 2009. Transmission customers have been allocated a total of \$12.2 million in capital costs to the end of 2009.

#### **Line 60 Dispatch Tool Re-Architecture**

218 The AESO's dispatch tool is one of the primary systems used to operate Alberta's energy market. The current dispatch tool architecture (that is, how the components of the system function together) is not able to reliably support software changes required by upcoming initiatives including wind integration, congestion management, and reliability assessment. At the time of preparation of the AESO's 2008 budget, the extent of the current dispatch tool limitations were not anticipated and the dispatch tool architecture improvements were not included. The critical requirement to improve the dispatch tool architecture was presented to stakeholders during 2008 with a budget request of \$2.2 million. The AESO Board Decision dated December 17, 2009 approved a corporate capital expenditure increase of \$5.0 million (as discussed under Line 58 above) of which \$2.5 million was assigned to this project, which

increased the overall budget to \$4.7 million. Management has initially assessed an allocation of 67% of the \$4.7 million, or \$3.1 million, to transmission customers.

- 219 By the end of 2009, \$5.4 million in capital costs has been incurred in accordance with the progress of the project: \$3.6 million in 2009 and \$1.8 million in 2008. Of these costs, the initial assessment has been to allocate 67%, or \$3.6 million, to transmission customers, of which \$2.4 million is recorded in Table 3-1 above for 2009. Through the progression of this multi-year project, additional costs have been identified related to the complexity associated with integrating the dispatch tool into other AESO systems (including the new EMS project discussed above) and addressing identified risks related to the cut-over of this operationally critical system.

### 3.2 2009 Revenue Variances

- 220 Table 3-2 presents AESO revenue (excluding revenue related to losses) forecast to be collected from base rates in effect during 2009. The table also includes recorded revenue as collected through 2009 base rates, as well as variances between forecast and recorded revenues in both dollar amounts and as a percentage of forecast revenue.
- 221 Base rates exclude Deferral Account Adjustment Rider C, which collects or refunds revenue during the year to align actual revenue with actual costs by rate and rate component. The AESO does not forecast Rider C amounts as part of its tariff applications, and Rider C is therefore not included in this discussion of variances from forecast.
- 222 The base rates which were in effect from January through September 2009 were approved at the conclusion of the AESO's 2007 tariff application proceeding, in Commission Order U2008-217 released on June 25, 2008. Those rates were based on the AESO's 2007 forecast revenue requirement and 2007 forecast billing determinants.
- 223 The base rates which were in effect from October through December 2009 were approved at the conclusion of the AESO's 2009 rates update proceeding, in Commission Decision

*Table 3-2 2009 Base Rate Revenue Variances (Excluding Losses), \$ 000 000*

Line No.	Forecast Revenue (a)	Recorded Revenue (b)	Variance Over (Under)		
			\$ (c)=(b)-(a)	% (d)=(c)÷(a)	
<b>Demand Transmission Service</b>					
1	Interconnection	\$525.5	\$528.6	\$3.1	0.6%
2	Operating Reserve	177.3	98.4	(78.9)	(44.5%)
3	Voltage Control	48.9	45.4	(3.5)	(7.2%)
4	Other System Support	7.8	7.9	0.1	1.1%
5	<b>Total DTS</b>	<b>\$759.5</b>	<b>\$680.3</b>	<b>(\$79.2)</b>	<b>(10.4%)</b>

Note: Numbers may not add due to rounding.

2009-141 released on September 18, 2009. Those rates were based on the AESO's 2009 forecast revenue requirement and 2009 forecast billing determinants.

- 224 To calculate the 2009 forecast revenue presented in Table 3-2, the AESO applied the rates in effect in each month of 2009 to its corresponding forecast of billing determinants for 2009. Those billing determinants were in turn based on the 2009 load forecast in the AESO's *Future Demand and Energy Outlook (2008-2028)*, 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* is available on the AESO website at [www.aeso.ca](http://www.aeso.ca) by following the path Transmission ► Planning ► Load Forecasting.
- 225 On an annual basis, transmission revenue depends on approved transmission tariff rates, pool price, and billed volumes of demand and energy. Variances arise due to unanticipated changes from forecasts of billing volumes and pool price. The 2009 recorded DTS base rates revenue in column (b) of Table 3-2 totalled \$680.3 million, which is \$79.2 million (or 10%) less than the 2009 forecast revenue of \$759.5 million. The base rate revenue variances for individual DTS rate components varied from about 44% below forecast to about 1% above forecast, as discussed below.
- 226 The 2009 recorded base rate revenue for operating reserve was \$98.4 million, which is \$78.9 million (or 44%) less than the 2009 forecast revenue of \$177.3 million. Operating reserve charges in the AESO's tariffs in effect during 2009 were determined as a percentage of pool price, and recorded pool price during 2009 averaged \$47.81/MWh — about 43% lower than the forecast pool price of \$84.43 on which the 2009 forecast operating reserve revenue was based.
- 227 The 2009 recorded revenue for voltage control was \$45.4 million, which is \$3.5 million (or 7%) less than the 2009 forecast revenue of \$48.9 million. The decrease results from billing volumes being lower than forecast due to the delay in forecast growth due to the world recession in 2009.
- 228 The interconnection and other system support base rate revenue variances were 0.6% and 1% above forecast respectively, which is considered small enough that a specific variance explanation is not required.

### 3.3 2009 Deferral Account Balance

- 229 Costs and revenue variances through the year give rise to deferral account balances. The deferral account balances for 2009 are summarized in Table 3-3, and reflect the 2009 recorded costs and revenue provided in Tables 3-1 and 3-2 respectively. Table 3-3 also includes Deferral Account Adjustment Rider C, which collects or refunds revenue to align actual revenues with actual costs by rate and rate component.
- 230 As noted in section 1.1 of this application, the AESO's tariff includes the use of deferral accounts, which were incorporated in the AESO's 2009 tariff through Working Capital Deficiency/Surplus Rider B and Deferral Account Adjustment Rider C. The AESO did not invoke Rider B during 2009, but determined Rider C charges and refunds in accordance

Table 3-3 2009 Deferral Account Summary (Excluding Losses), \$ 000 000

Line No.	Recorded Base Rate Revenue	Recorded Costs	Over (Under) Collection	Rider C Collected (Refunded)	Net Over (Under) Collection Variance		
					\$(a)	\$(b)	\$(c)=(a)+(b)
<b>Demand Transmission Service</b>							
1	Interconnection	\$528.6	(\$642.3)	(\$113.7)	\$72.8	(\$40.9)	(6.4%)
2	Operating Reserve	98.4	(103.7)	(5.2)	44.2	39.0	37.6%
3	Voltage Control	45.4	(24.3)	21.1	(17.1)	4.0	16.4%
4	Other System Support	7.9	(4.8)	3.1	(3.1)	(0.1)	(1.2%)
5	<b>Total DTS</b>	<b>\$680.3</b>	<b>(\$775.1)</b>	<b>(\$94.8)</b>	<b>\$96.8</b>	<b>\$2.0</b>	<b>0.3%</b>

Note: Numbers may not add due to rounding.

with the rider's approved purpose to "restore deferral account balances to zero over the following calendar quarter". The AESO sets Rider C rates each quarter based on estimates of deferral account balances at the end of the quarter and forecast billing volumes for the quarter.

231 The total recorded revenue collected with respect to 2009 is therefore the sum of revenue collected through base rates as discussed in section 3.2 above, plus revenue collected or refunded through Rider C during 2009.

232 The AESO notes that Rider C revenue attributed to a specific year includes amounts collected or refunded during the calendar year and, for years prior to 2008, in the first quarter of the following year. Rider C amounts in the first quarter of a year prior to 2008 have therefore historically related to two separate deferral account years. In deferral account reconciliation applications for those years, the first quarter Rider C amounts were prorated between the two years according to the amounts originally included in the Rider C calculation.

233 Prior to 2008, deferral account reconciliations were filed later in the following year, meaning that first quarter Rider C amounts could be included in their entirety. However, starting with the 2008 deferral account, the AESO now prepares reconciliations after initial settlement of December volumes. This would occur before collection or refund of the following year's first quarter Rider C amounts was complete. The AESO therefore modified its process at the end of 2008 to exclude deferral account year-end balances from the determination of Rider C for the first quarter of the following year. Deferral account year-end amounts are now not refunded or collected as part of the following year's first quarter Rider C, but are retained by the AESO for reconciliation in a deferral account reconciliation application.

234 Rider C collections and refunds for 2009 maintained the annual deferral account balance at a reasonable level of less than ±2% of costs for the other system support rate component. Larger balances existed for the other rate components:

- the interconnection rate component was undercollected by 6% of costs;

- the operating reserve rate component was overcollected by 38% of costs; and
- the voltage control rate component was overcollected by 16% of costs.

- 235 The undercollection of the interconnection rate component primarily resulting from the payment to AltaLink for costs incurred for the cancelled Genesee-Langdon 500 kV project in accordance with Commission Decision 2009-151 as discussed in section 3.1.1 of this application.
- 236 The operating reserve and voltage control rate components both include costs that are dependent on pool prices and natural gas prices as discussed in section 3.1.2 above. The overcollections of those rate components resulted primarily from recorded prices being significantly lower than the forecast prices used when estimating deferral account balances at the end of the fourth quarter for the calculation of the fourth quarter Rider C amounts.
- 237 Additional details on 2009 recorded costs and revenues are provided in Appendices B through F of this application. The allocation of the 2009 net deferral account balances to customers is discussed in section 9 of this application.

## 4 2008 FINANCIAL RESULTS AND DEFERRAL ACCOUNT BALANCE

- 238 The AESO's 2008 costs and revenues which are subject to retrospective deferral account reconciliation in this application are those related to wires, ancillary services, and the AESO's own administration (which includes other industry costs and general and administrative costs).
- 239 As discussed in section 2.1.2 of this application, effective January 1, 2006, transmission system losses are no longer subject to retrospective reconciliation. Since that time, Calibration Factor Rider E has adjusted loss factors for the recovery of the actual costs of losses on a prospective basis in accordance with section 33(1) of the *Transmission Regulation*. Therefore, the financial results and deferral account balance for 2008 discussed in this section do not include costs and revenues related to losses.
- ### 4.1 2008 Deferral Account Second Reconciliation
- 240 The AESO filed a first reconciliation of its 2008 deferral accounts as part of its 2008 deferral account reconciliation application submitted to the Commission on April 9, 2009. That first reconciliation included all cost and revenue transactions (except those related to losses) that occurred from January 1, 2008, to December 31, 2008 and that related to 2008. The first reconciliation deferral account balance for 2008 was a shortfall of \$4.6 million as provided in Table 2-3 in this application. The first reconciliation balance was settled with customers in June 2009 in accordance with the interim approval of the AESO's 2008 deferral account reconciliation application in Commission Decision 2009-074, released on June 3, 2009.
- 241 The first reconciliation resulted in \$876.3 million in costs and \$876.3 million in customer revenues (including Rider C collections and refunds as well as first reconciliation collections and refunds) being attributed to 2008.
- 242 In this 2009 deferral account reconciliation application, the second reconciliation for 2008 includes cost and revenue transactions (except those related to losses) that relate to 2008 and that occurred from January 1, 2008 to December 31, 2009. These transactions establish the 2008 production month data for second reconciliation purposes in this application. Compared to the first reconciliation, this second reconciliation includes additional transactions that relate to 2008 and that occurred after December 31, 2008 up to December 31, 2009.
- 243 The inclusion of these additional transactions increases the 2008 recorded costs to \$880.2 million and decreases the 2008 recorded revenue slightly to \$875.4 million.
- 244 Revenue and cost transactions that occurred from January 1, 2008, to December 31, 2009 may also relate, in whole or in part, to years other than 2008. In such instances, the transaction (or part of the transaction) which relates to another year has been assigned to the relevant year, in accordance with the production month presentation described in section 2.2 of this application. Detail on the assignment between 2008 and other years for transactions which occurred in 2009 is provided in Appendix E-1 of this application.

#### 4.2 2008 Cost Adjustments After First Reconciliation

- 245 The AESO's 2008 revenue requirement (excluding losses) was approved either by the Commission (for TFOs) or by the AESO Board (for ancillary services and the AESO's own administration), and is provided as column (a) in Table 4-1. Variances of recorded costs from that approved forecast were explained in the first reconciliation of the 2008 deferral account (for those transactions included in that first reconciliation). Those variances were approved in Commission Decision 2009-191 on the AESO's 2008 deferral account reconciliation released on October 29, 2009. No further discussion of those variances is provided in this application. Only 2008 cost adjustments which arise from transactions that occurred after the first reconciliation are discussed in this application.
- 246 Specifically, the 2008 cost adjustments (excluding those related to losses) which occurred after the first deferral account reconciliation and which are included in this second reconciliation are those transactions that:
- relate to 2008,
  - occurred after the cut-off date of December 31, 2008 for data included in the 2008 first reconciliation, and
  - occurred up to December 31, 2009.
- 247 These 2008 cost adjustments, together with the original 2008-related transactions which were included in the first reconciliation, establish the 2008 production year cost data for deferral account reconciliation purposes in this application.
- 248 Table 4-1 includes the following information for 2008:
- column (b) contains the 2008 recorded costs included in the first reconciliation in the 2008 application;
  - column (c) contains the 2008 recorded costs included in this application;
  - column (d) provides the additional amounts attributed to 2008 which occurred after the cut-off date for transactions included in the first reconciliation — that is, the cost variances between the first and second reconciliations; and
  - column (e) provides the 2008 additional amounts from column (d) as a percentage of the recorded costs from the first reconciliation in column (b).
- 249 As already discussed in the previous sections of this application, variances arise due to a number of factors, including finalization of TFO costs through Commission decisions, variances from forecast of volumes and pool price, delays and changes in AESO schedules and priorities, and generally expected adjustments that occur over time. In the first reconciliation for 2008, in the 2008 deferral account reconciliation application, the AESO considered a line item variance to be significant when it exceeded  $\pm\$5.0$  million, or, if it was smaller than  $\pm\$5.0$  million, when it was both at least  $\pm\$0.5$  million and at least  $\pm 10\%$  of the approved line item amount.
- 250 In this second reconciliation for 2008, variances are represented by cost adjustments which occurred after the first reconciliation. It seems inappropriate to use the same threshold levels for variance explanations for adjustments as would be used in a first reconciliation.

*Table 4-1 2008 First and Second Reconciliation Cost Variances (Excluding Losses), \$ 000 000*

Line No.	Approved Forecast	Recorded Costs		Variance Over (Under)		
		2008 1st DAR <sup>1</sup>	2009 2nd DAR <sup>1</sup>	\$	%	
	(a)	(b)	(c)	(d)=(c)-(b)	(e)=(d)÷(b)	
<b>WIRES</b>						
<b>TFO Wires-Related Costs</b>						
1	AltaLink	227.5	228.8	228.8	-	-
2	ATCO Electric Ltd.	176.6	178.9	180.4	1.5	0.8%
3	Isolated Generation	(10.0)	(6.7)	(6.7)	(0.0)	0.0%
4	Subtotal ATCO Costs	166.6	172.2	173.7	1.5	0.8%
5	ENMAX Power Corporation	31.9	31.9	31.9	-	-
6	EPCOR Transmission Inc.	36.8	44.3	43.4	(0.9)	(2.1%)
7	City of Lethbridge	4.5	4.5	4.5	-	-
8	TransAlta	4.2	4.2	4.1	(0.1)	(3.1%)
9	City of Red Deer	1.7	1.7	1.7	-	-
10	FortisAlberta Networks (Farm)	1.5	1.7	1.7	-	-
11	KEG Unit Transformers Conversion	-	3.3	5.5	2.2	65.7%
12	Subtotal TFO Wires-Related Costs	474.7	492.6	495.2	2.6	0.5%
<b>Non-Wires Costs</b>						
13	Invitation to Bid on Credits (IBOC)	1.7	1.5	1.5	-	-
14	Location Based Credit Standing Offer (LBC SO)	7.1	7.0	7.0	0.1	0.8%
15	Subtotal IBOC/LBC SO Costs	8.8	8.5	8.5	0.1	0.7%
16	TOTAL WIRES COSTS	483.5	501.1	503.7	2.6	0.5%
<b>ANCILLARY SERVICES</b>						
<b>Operating Reserves</b>						
Active						
17	Regulating	55.7	70.3	70.3	-	-
18	Spinning	74.6	94.7	94.7	-	-
19	Supplemental	66.5	79.1	79.1	-	-
20	Subtotal Active Reserves	196.8	244.1	244.1	-	-
Standby						
21	Regulating	6.3	8.7	8.7	-	-
22	Spinning	7.7	12.0	12.0	-	-
23	Supplemental	4.3	4.8	4.8	-	-
24	Subtotal Standby Reserves	18.3	25.6	25.6	-	-
25	Trading Fees & Other Related Charges	-	(7.4)	(7.5)	(0.1)	1.5%
26	Subtotal Operating Reserves	215.1	262.3	262.2	(0.1)	(0.0%)
<b>Other Ancillary Services</b>						
27	Brazeau Fast Ramp (Previously GRAS)	0.7	0.1	0.1	-	-
28	Black Start	2.0	1.8	1.8	0.0	0.7%
29	Transmission Must-Run (TMR)	40.2	42.1	43.4	1.4	3.2%
30	Under Frequency Mitigation	5.0	4.0	4.0	-	-
31	Subtotal Other Ancillary Services	48.0	48.0	49.4	1.4	2.8%

Table 4-1 2008 First and Second Reconciliation Cost Variances (Excluding Losses), \$ 000 000  
(cont'd)

Line No.	Approved Forecast (a)	Recorded Costs		Variance Over (Under)		
		2008 1st DAR <sup>1</sup> (b)	2009 2nd DAR <sup>1</sup> (c)	\$ (d)=(c)-(b)	% (e)=(d)÷(b)	
<b>Poplar Hill/ILRAS</b>						
32	Poplar Hill	1.9	2.0	2.0	-	-
33	Interruptible Load Remedial Action Scheme (ILRAS)	0.8	0.0	0.0	-	-
34	Generator Remedial Action Scheme (RAS)	-	-	-	-	-
35	<b>Subtotal Poplar Hill/ILRAS</b>	<b>2.8</b>	<b>2.0</b>	<b>2.0</b>	<b>-</b>	<b>-</b>
36	<b>TOTAL ANCILLARY SERVICES</b>	<b>265.9</b>	<b>312.4</b>	<b>313.6</b>	<b>1.3</b>	<b>0.4%</b>
<b>OTHER INDUSTRY COSTS</b>						
37	External Regulatory Costs	4.1	0.8	0.8	-	-
38	Western Electricity Coordinating Council (WECC)	2.5	2.1	2.1	-	-
39	Share of AUC Overhead	2.5	8.6	8.6	-	-
40	<b>TOTAL OTHER INDUSTRY COSTS</b>	<b>9.1</b>	<b>11.5</b>	<b>11.5</b>	<b>-</b>	<b>-</b>
<b>GENERAL AND ADMINISTRATIVE COSTS</b>						
<b>Administrative Costs</b>						
41	Staff and Benefits	28.0	26.0	26.0	-	-
42	Consultants	5.8	7.7	7.7	-	-
43	Board Members Fees	0.5	0.4	0.4	-	-
44	Travel and Training	1.7	1.6	1.6	-	-
45	Legal	0.5	0.5	0.5	-	-
46	Audits/Reviews	0.6	0.3	0.3	-	-
47	Rent <sup>2</sup>	2.0	2.2	2.2	-	-
48	Insurance	0.4	0.4	0.4	-	-
49	Other Administrative Costs	2.4	4.2	4.2	-	-
50	Telecomm and IT Maintenance	2.3	2.5	2.5	-	-
51	Interconnection Fees (Offset)	-	0.0	0.0	-	-
52	<b>Total Administrative Costs</b>	<b>44.2</b>	<b>46.0</b>	<b>46.0</b>	<b>-</b>	<b>-</b>
<b>General Costs</b>						
53	Interest	1.7	0.9	0.9	-	-
54	Amortization and Depreciation	5.8	4.4	4.4	-	-
55	<b>Total General Costs</b>	<b>7.5</b>	<b>5.3</b>	<b>5.3</b>	<b>-</b>	<b>-</b>
56	<b>TOTAL GENERAL &amp; ADMIN COSTS</b>	<b>51.7</b>	<b>51.3</b>	<b>51.3</b>	<b>-</b>	<b>-</b>
57	<b>Total G&amp;A and Other Industry Costs</b>	<b>60.8</b>	<b>62.8</b>	<b>62.8</b>	<b>-</b>	<b>-</b>
58	<b>TOTAL REVENUE REQUIREMENT</b>	<b>810.2</b>	<b>876.2</b>	<b>880.2</b>	<b>3.9</b>	<b>0.4%</b>

Table 4-1 2008 First and Second Reconciliation Cost Variances (Excluding Losses), \$ 000 000  
(cont'd)

Line No.	Approved Forecast (a)	Recorded Costs		Variance Over (Under)	
		2008 1st DAR <sup>1</sup> (b)	2009 2nd DAR <sup>1</sup> (c)	\$ (d)=(c)-(b)	% (e)=(d)÷(b)
<b>CAPITAL</b>					
59	General Capital	5.8	6.0	6.0	-
60	Calgary Place Office Renovations	-	0.7	0.7	-
61	Energy Management System (EMS)	-	6.2	6.2	-
62	Dispatch Tool Architecture Improvements	-	1.2	1.2	-
63	<b>Total Capital</b>	<b>5.8</b>	<b>14.1</b>	<b>14.1</b>	<b>-</b>

Notes: Numbers may not add due to rounding.

Shaded numbers indicate significant variances which are discussed in the text.

<sup>1</sup> DAR means Deferral Account Reconciliation.

<sup>2</sup> Amortization of Rent Free Period not included in 2008 Recorded Costs on Line 47.

The AESO considers it reasonable to reduce the variance explanation thresholds by half, recognizing that costs may have varied from forecast in the first reconciliation and may also vary again due to further adjustments in this second reconciliation. Although each variance might be less than the  $\pm\$5.0$  million threshold, together they may exceed it.

251 Therefore, in Table 4-1, the AESO considered a line item variance to be significant when it exceeded  $\pm\$2.5$  million, or, if it was smaller than  $\pm\$2.5$  million, when it was both at least  $\pm\$0.25$  million and at least  $\pm 5\%$  of the first reconciliation recorded costs item amount. Variances exceeding these thresholds are shaded in Table 4-1, with explanations provided by line number in the following discussion. Where variances were either less than  $\pm\$0.25$  million or less than  $\pm 5\%$  (except where such variance is  $\pm\$2.5$  million or greater) explanations are not provided, as such variances are considered small enough that specific variance explanations are not required.

#### 4.2.1 Wires Costs

252 Recorded costs for TFO wires are based on actual billings by the TFOs to the AESO under final or interim tariffs or resulting from deferral account reconciliations or other adjustments approved for the TFOs. The 2008 first reconciliation recorded costs were based on actual billings by the TFOs to the AESO for 2008 up to December 31, 2008, which was the data cut-off date for the AESO's 2008 deferral account reconciliation application. The second reconciliation recorded costs were similarly based on actual billings by the TFOs to the AESO for 2008 but up to December 31, 2009, which is the data cut-off date for this application.

253 The AESO notes that final approval has not yet been issued for the 2008 TFO tariff of ENMAX Power Corporation. If ENMAX's final TFO tariff differs from the interim tariff included in the 2008 wires costs in this deferral account reconciliation, the difference will be included in the next deferral account reconciliation application filed after the final tariff is approved.

### Line 11 KEG Unit Transformers Conversion

- 254 The 2008 second reconciliation recorded cost for the KEG unit transformers conversion was \$5.5 million, which is \$2.2 million (or 66%) more than the first reconciliation recorded costs of \$3.3 million. These costs arose from directions in Commission Decision 2008-101 regarding AESO recovery of costs for Keephills-Ellerslie-Genesee (“KEG”) conversion of unit transformers, released on October 21, 2008.
- 255 The AESO received and paid one additional invoice in 2009 from EPCOR Power Development Corporation for \$2.2 million incurred as direct costs resulting from the KEG unit transformers conversion. Total costs were consistent with those anticipated in the AESO’s application for recovery of KEG unit transformers conversion costs, and were within the ±30% accuracy of the \$4.5 million cost estimate provided in the application.
- 256 Work on the project was completed in 2008, and costs for the project have been finalized and attributed to 2008. The AESO engaged a consultant to review the costs, including a detailed examination based on the direction in Decision 2008-101. The review concluded that the costs invoiced to the AESO were the direct costs of carrying out the project and were prudent, accurate, and complete. The AESO has added the \$49,000 cost of the consultant’s review to the KEG project costs in this application.
- 257 In accordance with the direction in Commission Decision 2009-191 on the AESO’s 2008 deferral account reconciliation (section 5, page 8, paragraph 43), the additional cost for the project paid in 2009 has been included in this deferral account reconciliation.

### 4.3 2008 Revenue Adjustments After First Reconciliation

- 258 The AESO’s 2008 forecast “base rate” revenue (excluding losses) was discussed in the 2008 deferral account reconciliation application. Base rates exclude Deferral Account Adjustment Rider C, which collects or refunds revenue during the year to align actual revenue with actual costs by rate and rate component (excluding losses). The AESO does not forecast Rider C amounts as part of its tariff applications, and Rider C is therefore not included in this discussion of variances from forecast. Base rate revenue also excludes any amounts collected or refunded through deferral account reconciliation applications.
- 259 Variances of recorded base rate revenue from the 2008 forecast were explained in the first reconciliation of the 2008 deferral account (for those transactions included in that first reconciliation). Those variances were approved in Commission Decision 2009-191 on the AESO’s 2008 deferral account reconciliation released on October 29, 2009. No further discussion of those base rate revenue variances is provided in this application. Only revenue adjustments which arise from transactions that occurred after the first reconciliation are discussed in this application.
- 260 Specifically, the 2008 revenue adjustments (excluding those related to losses) which occurred after the first deferral account reconciliation and which are included in this second reconciliation are those transactions that:
- relate to 2008,

- occurred after the cut-off date of December 31, 2008 for data included in the 2008 first reconciliation, and
- occurred up to December 31, 2009.

261 These 2008 revenue adjustments, together with the original 2008-related transactions which were included in the first reconciliation, establish the 2008 production year revenue data for deferral account reconciliation purposes in this application.

262 Table 4-2 accordingly includes the following information for 2008:

- column (b) contains the 2008 recorded base rate revenue included in the first reconciliation in the 2008 application;
- column (c) contains the 2008 recorded base rate revenue included in this application;
- column (d) provides the additional base rate revenue amounts attributed to 2008 which occurred after the cut-off date for transactions included in the first reconciliation — that is, the revenue variances between the first and second reconciliations; and
- column (e) provides the 2008 additional revenue amounts from column (d) as a percentage of the recorded revenue from the first reconciliation in column (b).

263 The 2008 second reconciliation recorded revenue (excluding revenue related to losses) was \$737.2 million, which is \$0.9 million (or 0.1%) less than the first reconciliation recorded revenue of \$738.1 million.

264 On an annual basis, transmission revenue depends on approved transmission tariff rates, pool price, and billed volumes of demand and energy. Revenue variances after the first reconciliation generally arise due to billing adjustments, primarily reflecting changes to metered volumes such as those that occur in interim and final settlement. There were no significant variances between the first and second reconciliation recorded revenues for 2008.

*Table 4-2 2008 First and Second Reconciliation Revenue Variances (Excluding Losses),  
\$ 000 000*

Line No.	Forecast Revenue	Recorded Revenue		Variance Over (Under)		
		2008 1st DAR <sup>1</sup>	2009 2nd DAR <sup>1</sup>	\$	%	
	(a)	(b)	(c)	(d)=(c)-(b)	(e)=(d)÷(b)	
<b>Demand Transmission Service</b>						
1	Interconnection	\$492.5	\$494.3	\$493.5	(\$0.8)	(0.2%)
2	Operating Reserve	178.9	183.5	183.4	(0.0)	(0.0%)
3	Voltage Control	55.9	52.1	52.0	(0.0)	(0.0%)
4	Other System Support	9.1	8.3	8.2	(0.0)	(0.2%)
5	<b>Total DTS</b>	<b>\$736.4</b>	<b>\$738.1</b>	<b>\$737.2</b>	<b>(\$0.9)</b>	<b>(0.1%)</b>

Note: Numbers may not add due to rounding.

<sup>1</sup> DAR means Deferral Account Reconciliation.

#### 4.4 2008 Second Reconciliation Deferral Account Balance

- 265 Costs and revenue variances attributed to a year give rise to deferral account balances. The deferral account balances for the 2008 second reconciliation are summarized in Table 4-3, and reflect the 2008 second reconciliation costs and revenues provided in Tables 4-1 and 4-2 respectively.
- 266 As noted in section 1.1 of this application, the AESO's tariff includes the use of deferral accounts, which were incorporated in the AESO's 2008 tariff through Working Capital Deficiency/Surplus Rider B and Deferral Account Adjustment Rider C. The AESO did not invoke Rider B during 2008, but determined Rider C charges and refunds in accordance with the rider's approved purpose to "restore deferral account balances to zero over the following calendar quarter". The AESO sets Rider C rates each quarter based on estimates of deferral account balances at the end of that quarter and forecast billing volumes for that quarter. Rider C charges and refunds attributed to 2008 are provided in column (d) of Table 4-3.
- 267 The first reconciliation of the 2008 deferral account in the AESO's 2008 deferral account reconciliation application resulted in a \$4.6 million shortfall attributed to 2008, as illustrated in Table 2-2 in section 2.3 of this application. The first reconciliation shortfall was collected from customers in the interim settlement in late June 2009 of the AESO's 2008 deferral account balances, which was approved on a final basis in Commission Decision 2009-191. First reconciliation settlement amounts attributed to 2008 are provided in column (e) of Table 4-3, and restored all 2008 deferral account balances to zero based on the transactions included in the 2008 first reconciliation.
- 268 However, this second reconciliation includes adjustments to costs and revenues that occurred after the first reconciliation of the 2008 deferral account, as discussed in sections 4.2 and 4.3 where explanations were provided when the resulting line item variances were significant.

*Table 4-3 2008 Second Reconciliation Deferral Account Summary (Excluding Losses), \$ 000 000*

Line No.	Recorded		Over	Prior Deferral Account		Net Over (Under)		
	Base Rate Revenue	Recorded Costs	(Under) Collection	Collections (Refunds) Rider C	1st DAR <sup>1</sup>	\$	%	
	(a)	(b)	(c)=(a)+(b)	(d)	(e)	(f)=Σ(c):(e)	(g)=- (f)÷(b)	
<b>Demand Transmission Service</b>								
1	Interconnection	\$493.5	(\$566.5)	(\$73.0)	\$61.8	\$7.8	(\$3.4)	(0.6%)
2	Operating Reserve	183.4	(264.2)	(80.8)	83.1	(2.3)	0.1	0.0%
3	Voltage Control	52.0	(43.4)	8.6	(9.7)	(0.3)	(1.4)	(3.1%)
4	Other System Support	8.2	(6.0)	2.2	(1.8)	(0.5)	(0.0)	(0.3%)
5	<b>Total DTS</b>	<b>\$737.2</b>	<b>(\$880.2)</b>	<b>(\$142.9)</b>	<b>\$133.5</b>	<b>\$4.6</b>	<b>(\$4.8)</b>	<b>(0.5%)</b>

Note: Numbers may not add due to rounding.

<sup>1</sup> DAR means Deferral Account Reconciliation.



- 269 The interconnection charges deferral account balance has increased to an undercollection of \$3.4 million (or 0.6% of recorded costs), primarily due to additional invoices paid in 2009 for direct costs resulting from the KEG unit transformers conversion as discussed above in section 4.2.1.
- 270 The voltage control charges deferral account balance has increased to an undercollection of \$1.4 million (or 3% of recorded costs), primarily due to adjustments for transmission must-run ("TMR") services in 2008 as indicated on line 29 of Table 4-1.
- 271 Deferral account balances for operating reserve and other system support charges have not changed significantly from the first reconciliation.
- 272 The impact of all 2008 cost and revenue adjustments is a deferral account net balance increase to an undercollection of \$4.8 million (or 0.5% of recorded costs), compared to the zero balance that existed after settlement of amounts included in the first reconciliation.
- 273 Additional details on 2008 recorded costs and revenues are provided in Appendices B through F of this application. The allocation of the 2008 net deferral account balances to customers is discussed in section 9 of this application.

## 5 2007 FINANCIAL RESULTS AND DEFERRAL ACCOUNT BALANCE

- 274 The AESO's 2007 costs and revenues which are subject to retrospective deferral account reconciliation in this application are those related to wires, ancillary services, and the AESO's own administration (which includes other industry costs and general and administrative costs).
- 275 As discussed in section 2.1.2 of this application, effective January 1, 2006, transmission system losses are no longer subject to retrospective reconciliation. Since that time, calibration factor Rider E has adjusted loss factors for the recovery of the actual costs of losses on a prospective basis in accordance with section 33(1) of the *Transmission Regulation*. Therefore, the financial results and deferral account balance for 2007 discussed in this section do not include costs and revenues related to losses.
- ### 5.1 2007 Deferral Account Third Reconciliation
- 276 The AESO filed a first reconciliation of its 2007 deferral accounts as part of its 2004-2007 deferral account reconciliation application submitted to the Commission on June 2, 2008. The AESO subsequently filed a second reconciliation of its 2007 deferral accounts as part of its 2008 deferral account reconciliation application submitted to the Commission on April 9, 2009. That second reconciliation included all cost and revenue transactions (except those related to losses) that occurred from January 1, 2007, to December 31, 2008 and that related to 2007. The second reconciliation deferral account balance for 2007 was a shortfall of \$1.4 million as provided in Table 2-3 in this application. The second reconciliation balance was settled with customers in June 2009 in accordance with the interim settlement of the AESO's 2008 deferral account reconciliation approved in Commission Decision 2009-074, released on June 3, 2009.
- 277 The second reconciliation resulted in \$743.0 million in costs and \$743.0 million in customer revenues (including Rider C collections and refunds as well as first and second reconciliation collections and refunds) being attributed to 2007.
- 278 In this 2009 deferral account reconciliation application, the third reconciliation for 2007 includes cost and revenue transactions (except those related to losses) that relate to 2007 and that occurred from January 1, 2007 to December 31, 2009. These transactions establish the 2007 production month data for third reconciliation purposes in this application. Compared to the second reconciliation, this third reconciliation includes additional transactions that relate to 2007 and that occurred after December 31, 2008 up to December 31, 2009.
- 279 The inclusion of these additional transactions decreases the 2007 recorded costs to \$739.3 million and decreases the 2007 recorded revenue slightly to \$742.7 million.
- 280 Revenue and cost transactions that occurred from January 1, 2007, to December 31, 2009 may also relate, in whole or in part, to years other than 2007. In such instances, the transaction (or part of the transaction) which relates to another year has been assigned to the relevant year, in accordance with the production month presentation described in

section 2.2 of this application. Detail on the assignment between 2007 and other years for transactions which occurred in 2007, 2008, and 2009 is provided in Appendix E-1 of this application.

## 5.2 2007 Cost Adjustments After Second Reconciliation

- 281 The AESO's 2007 revenue requirement (excluding losses) was approved in Commission Decision 2008-037 on the AESO's 2007 general tariff application refiling, released on May 8, 2008, and is provided as column (a) in Table 5-1. Variances of recorded costs from that approved forecast were explained in the first and second reconciliations of the 2007 deferral account (for those transactions included in those first and second reconciliations). First reconciliation variances were approved in Commission Decision 2009-010 on the AESO's 2004-2007 deferral account reconciliation released on January 27, 2009. Second reconciliation variances were approved in Commission Decision 2009-191 on the AESO's 2008 deferral account reconciliation released on October 29, 2009. No further discussion of those variances is provided in this application. Only 2007 cost adjustments which arise from transactions that occurred after the second reconciliation are discussed in this application.
- 282 Specifically, the 2007 cost adjustments (excluding those related to losses) which occurred after the second deferral account reconciliation and which are included in this third reconciliation are those transactions that:
- relate to 2007,
  - occurred after the cut-off date of December 31, 2008 for data included in the 2007 second reconciliation, and
  - occurred up to December 31, 2009.
- 283 These 2007 cost adjustments, together with the original 2007-related transactions which were included in the first and second reconciliations, establish the 2007 production year cost data for deferral account reconciliation purposes in this application.
- 284 Table 5-1 includes the following information for 2007:
- column (b) contains the 2007 recorded costs included in the second reconciliation in the 2008 application;
  - column (c) contains the 2007 recorded costs included in this application;
  - column (d) provides the additional amounts attributed to 2007 which occurred after the cut-off date for transactions included in the second reconciliation — that is, the cost variances between the second and third reconciliations; and
  - column (e) provides the 2007 additional amounts from column (d) as a percentage of the recorded costs from the second reconciliation in column (b).
- 285 As already discussed in the previous sections of this application, variances arise due to a number of factors, including finalization of TFO costs through Commission decisions, variances from forecast of volumes and pool price, delays and changes in AESO schedules and priorities, and generally expected adjustments that occur over time. In the second reconciliation for 2007, in the 2008 deferral account reconciliation application, the AESO

*Table 5-1 2007 Second and Third Reconciliation Cost Variances (Excluding Losses), \$ 000 000*

Line No.	Approved Forecast (a)	Recorded Costs		Variance Over (Under)		
		2008 2nd DAR <sup>1</sup> (b)	2009 3rd DAR <sup>1</sup> (c)	\$ (d)=(c)-(b)	% (e)=(d)÷(b)	
<b>WIRES</b>						
<b>TFO Wires-Related Costs</b>						
1	AltaLink	208.0	208.0	208.0	-	-
2	ATCO Electric Ltd.	169.5	169.5	165.7	(3.8)	(2.2%)
3	Isolated Generation	(7.9)	(5.9)	(5.9)	-	-
4	Subtotal ATCO Costs	161.6	163.6	159.8	(3.8)	(2.3%)
5	ENMAX Power Corporation	31.9	31.9	31.9	-	-
6	EPCOR Transmission Inc.	36.8	34.7	34.5	(0.2)	(0.5%)
7	City of Lethbridge	4.4	4.4	4.4	-	-
8	TransAlta	4.2	4.2	3.8	(0.3)	(7.5%)
9	Refund to the AESO	-	-	-	-	-
10	Subtotal TransAlta Costs	4.2	4.2	3.8	(0.3)	(7.5%)
11	City of Red Deer	1.7	1.7	1.7	-	-
12	FortisAlberta Networks (Farm)	1.5	1.5	1.5	-	-
13	<b>Subtotal TFO Wires-Related Costs</b>	<b>450.0</b>	<b>449.9</b>	<b>445.6</b>	<b>(4.3)</b>	<b>(1.0%)</b>
<b>Non-Wires Costs</b>						
14	Invitation to Bid on Credits (IBOC)	1.7	1.6	1.6	-	-
15	Location Based Credit Standing Offer (LBC SO)	6.8	5.7	5.8	0.1	1.2%
16	<b>Subtotal IBOC/LBC SO Costs</b>	<b>8.5</b>	<b>7.4</b>	<b>7.4</b>	<b>0.1</b>	<b>0.9%</b>
17	<b>TOTAL WIRES COSTS</b>	<b>458.5</b>	<b>457.2</b>	<b>453.0</b>	<b>(4.2)</b>	<b>(0.9%)</b>
<b>ANCILLARY SERVICES</b>						
<b>Operating Reserves</b>						
Active						
18	Regulating	34.7	46.7	46.7	0.0	0.0%
19	Spinning	41.1	64.9	64.9	-	-
20	Supplemental	32.0	56.1	56.1	-	-
21	<b>Subtotal Active Reserves</b>	<b>107.8</b>	<b>167.7</b>	<b>167.7</b>	<b>0.0</b>	<b>0.0%</b>
Standby						
22	Regulating	4.6	6.2	6.2	-	-
23	Spinning	5.7	8.8	8.8	-	-
24	Supplemental	3.1	2.7	2.7	-	-
25	<b>Subtotal Standby Reserves</b>	<b>13.4</b>	<b>17.8</b>	<b>17.8</b>	<b>-</b>	<b>-</b>
26	Trading Fees & Other Related Charges	-	(4.8)	(4.8)	-	-
27	<b>Subtotal Operating Reserves</b>	<b>121.2</b>	<b>180.7</b>	<b>180.7</b>	<b>0.0</b>	<b>0.0%</b>
<b>Other Ancillary Services</b>						
28	Brazeau Fast Ramp (Previously GRAS)	0.6	0.6	0.6	-	-
29	Black Start	2.8	2.0	2.0	-	-
30	Transmission Must-Run (TMR)	50.8	46.5	47.0	0.5	1.1%
31	Under Frequency Mitigation	5.9	4.9	4.9	-	-
32	<b>Subtotal Other Ancillary Services</b>	<b>60.2</b>	<b>54.0</b>	<b>54.5</b>	<b>0.5</b>	<b>0.9%</b>

Table 5-1 2007 Second and Third Reconciliation Cost Variances (Excluding Losses), \$ 000 000  
(continued)

Line No.	Approved Forecast (a)	Recorded Costs		Variance Over (Under)		
		2008 2nd DAR <sup>1</sup> (b)	2009 3rd DAR <sup>1</sup> (c)	\$ (d)=(c)-(b)	% (e)=(d)÷(b)	
<b>Poplar Hill/ILRAS</b>						
33	Poplar Hill	1.9	2.0	2.0	-	-
34	Interruptible Load Remedial Action Scheme (ILRAS)	0.7	0.0	0.0	-	-
35	Generator Remedial Action Scheme (RAS)	0.5	-	-	-	-
36	<b>Subtotal Poplar Hill/ILRAS</b>	<b>3.1</b>	<b>2.0</b>	<b>2.0</b>	<b>-</b>	<b>-</b>
37	<b>TOTAL ANCILLARY SERVICES</b>	<b>184.5</b>	<b>236.7</b>	<b>237.2</b>	<b>0.5</b>	<b>0.2%</b>
<b>OTHER INDUSTRY COSTS</b>						
38	External Regulatory Costs	1.1	0.7	0.7	-	-
39	Western Electricity Coordinating Council (WECC)	2.2	1.8	1.8	-	-
40	Share of EUB Overhead	2.2	2.3	2.3	-	-
41	<b>TOTAL OTHER INDUSTRY COSTS</b>	<b>5.5</b>	<b>4.8</b>	<b>4.8</b>	<b>-</b>	<b>-</b>
<b>GENERAL AND ADMINISTRATIVE COSTS</b>						
<b>Administrative Costs</b>						
42	Staff and Benefits	24.4	23.9	23.9	-	-
43	Consultants	3.3	5.9	5.9	-	-
44	Board Members Fees	0.4	0.3	0.3	-	-
45	Travel and Training	1.1	1.2	1.2	-	-
46	Legal	0.4	1.1	1.1	-	-
47	Audits/Reviews	0.4	0.3	0.3	-	-
48	Rent <sup>2</sup>	1.9	1.8	1.8	-	-
49	Insurance	0.4	0.4	0.4	-	-
50	Other Administrative Costs	1.5	1.7	1.7	-	-
51	Telecomm and IT Maintenance	2.1	2.6	2.6	-	-
52	Interconnection Fees (Offset)	(0.2)	(0.0)	(0.0)	-	-
53	<b>Total Administrative Costs</b>	<b>35.7</b>	<b>39.0</b>	<b>39.0</b>	<b>-</b>	<b>-</b>
<b>General Costs</b>						
54	Interest	1.2	1.4	1.4	-	-
55	Amortization and Depreciation	4.4	3.9	3.9	-	-
56	Taxes	-	-	-	-	-
57	<b>Total General Costs</b>	<b>5.6</b>	<b>5.3</b>	<b>5.3</b>	<b>-</b>	<b>-</b>
58	<b>TOTAL GENERAL &amp; ADMIN COSTS</b>	<b>41.3</b>	<b>44.3</b>	<b>44.3</b>	<b>-</b>	<b>-</b>
59	<b>Total G&amp;A and Other Industry Costs</b>	<b>46.8</b>	<b>49.1</b>	<b>49.1</b>	<b>-</b>	<b>-</b>
60	<b>TOTAL REVENUE REQUIREMENT</b>	<b>689.8</b>	<b>743.0</b>	<b>739.3</b>	<b>(3.7)</b>	<b>(0.5%)</b>

Table 5-1 2007 Second and Third Reconciliation Cost Variances (Excluding Losses), \$ 000 000  
(continued)

Line No.	Approved Forecast (a)	Recorded Costs		Variance Over (Under)	
		2008 2nd DAR <sup>1</sup> (b)	2009 3rd DAR <sup>1</sup> (c)	\$ (d)=(c)-(b)	% (e)=(d)÷(b)
<b>CAPITAL</b>					
61	General Capital	4.2	3.9	3.9	-
62	System Coordination Centre	-	0.2	0.2	-
63	<b>Total Capital</b>	<b>4.2</b>	<b>4.1</b>	<b>4.1</b>	<b>-</b>

Notes: Numbers may not add due to rounding.

Shaded numbers indicate significant variances which are discussed in the text.

<sup>1</sup> DAR means Deferral Account Reconciliation.

<sup>2</sup> Amortization of Rent Free Period not included in 2007 Recorded Costs on Line 48.

considered a line item variance to be significant when it exceeded  $\pm\$2.0$  million, or, if it was smaller than  $\pm\$2.0$  million, when it was both at least  $\pm\$0.2$  million and at least  $\pm 5\%$  of the approved line item amount.

286 In this third reconciliation for 2007, variances are represented by cost adjustments which occurred after the second reconciliation. It seems inappropriate to use the same threshold levels for variance explanations for adjustments as would be used in a second reconciliation. The AESO considers it reasonable to reduce the variance explanation thresholds by one-third, recognizing that costs may have varied from forecast in the first and second reconciliations and may also vary again due to further adjustments in this third reconciliation. Although each variance might be less than the first or second reconciliation threshold, together they may exceed it.

287 Therefore, in Table 5-1, the AESO considered a line item variance to be significant when it exceeded  $\pm\$1.3$  million, or, if it was smaller than  $\pm\$1.3$  million, when it was both at least  $\pm\$0.13$  million and at least  $\pm 3\%$  of the first reconciliation recorded costs item amount. Variances exceeding these thresholds are shaded in Table 5-1, with explanations provided by line number in the following discussion. Where variances were either less than  $\pm\$0.13$  million or less than  $\pm 3\%$  (except where such variance is  $\pm\$1.3$  million or greater) explanations are not provided, as such variances are considered small enough that specific variance explanations are not required.

### 5.2.1 Wires Costs

288 Recorded costs for TFO wires are based on actual billings by the TFOs to the AESO under final or interim tariffs or resulting from deferral account reconciliations or other adjustments approved for the TFOs. The 2007 second reconciliation recorded costs were based on actual billings by the TFOs to the AESO for 2007 up to December 31, 2008, which was the data cut-off date for the AESO's 2008 deferral account reconciliation application. The third reconciliation recorded costs were similarly based on actual billings by the TFOs to the

AESO for 2007 but up to December 31, 2009, which is the data cut-off date for this application.

289 The AESO notes that final approval has not yet been issued for the 2007 TFO tariff of ENMAX Power Corporation. If that TFO's final tariff differs from the interim tariff included in the 2007 wires costs in this deferral account reconciliation, the difference will be included in the next deferral account reconciliation application filed after the final tariff is approved.

#### **Line 2 ATCO Electric Ltd.**

290 The 2007 third reconciliation recorded cost for ATCO Electric wires was \$165.7 million, which is \$3.8 million (or 2%) less than the second reconciliation recorded cost of \$169.5 million. The second reconciliation cost reflected billings resulting from Alberta Energy and Utilities Board Decision 2007-104 released December 21, 2007, which approved ATCO Electric's 2007 transmission facility owner tariff on a final basis. The third reconciliation cost reflected billings for the following additional amounts for ATCO Electric:

- a charge to the AESO of \$1.1 million resulting from Commission Decision 2009-032 on the review of Decision 2007-071 on ATCO Electric's 2007-2008 general tariff application;
- a refund to the AESO of \$3.8 million reflecting disposal of ATCO Electric's 2007 transmission deferral accounts and annual filing for adjustment balances included in Commission Decision 2009-087 on ATCO Electric's 2009-2010 general tariff application; and
- a refund to the AESO of \$1.1 million resulting from Commission Decision 2009-199 on ATCO Electric's 2008 deferral accounts and annual filing for adjustment balances.

#### **Line 8 TransAlta**

291 The 2007 third reconciliation recorded cost for TransAlta wires was \$3.8 million, which is \$0.3 million (or 7%) less than the second reconciliation recorded cost of \$4.2 million. The second reconciliation cost reflected billings resulting from Alberta Energy and Utilities Board Decision 2007-050 released June 19, 2007, which approved TransAlta's 2007 transmission facility owner tariff on a final basis. The third reconciliation cost included a refund to the AESO of \$0.3 million reflecting settlement of TransAlta's 2007 transmission deferral accounts included in Commission Decision 2009-151 on AltaLink's and TransAlta's 2009-2010 transmission facility owner tariffs.

### **5.3 2007 Revenue Adjustments After Second Reconciliation**

292 The AESO's 2007 forecast "base rate" revenue (excluding losses) was discussed in the 2004-2007 deferral account reconciliation application. Base rates exclude Deferral Account Adjustment Rider C, which collects or refunds revenue during the year to align actual revenue with actual costs by rate and rate component (excluding losses). The AESO does not forecast Rider C amounts as part of its tariff applications, and Rider C is therefore not included in this discussion of variances from forecast. Base rate revenue also excludes any amounts collected or refunded through deferral account reconciliation applications.

293 Variances of recorded base rate revenue from the 2007 first reconciliation were explained in the second reconciliation of the 2007 deferral account (for those transactions included in that second reconciliation). Those variances were approved in Commission Decision

2009-191 on the AESO's 2008 deferral account reconciliation released on October 29, 2009. No further discussion of those base rate revenue variances is provided in this application. Only revenue adjustments which arise from transactions that occurred after the second reconciliation are discussed in this application.

294 Specifically, the 2007 revenue adjustments (excluding those related to losses) which occurred after the second deferral account reconciliation and which are included in this third reconciliation are those transactions that:

- relate to 2007,
- occurred after the cut-off date of December 31, 2008 for data included in the 2007 second reconciliation, and
- occurred up to December 31, 2009.

295 These 2007 revenue adjustments, together with the 2007-related transactions which were included in the first and second reconciliations, establish the 2007 production year revenue data for deferral account reconciliation purposes in this application.

296 Table 5-2 accordingly includes the following information for 2007:

- column (b) contains the 2007 recorded base rate revenue included in the second reconciliation in the 2008 application;
- column (c) contains the 2007 recorded base rate revenue included in this application;
- column (d) provides the additional base rate revenue amounts attributed to 2007 which occurred after the cut-off date for transactions included in the second reconciliation — that is, the revenue variances between the second and third reconciliations; and
- column (e) provides the 2007 additional revenue amounts from column (d) as a percentage of the recorded revenue from the second reconciliation in column (b).

*Table 5-2 2007 Second and Third Reconciliation Revenue Variances (Excluding Losses),  
\$ 000 000*

Line No.	Forecast Revenue	Recorded Revenue		Variance Over (Under)		
		2008 2nd DAR <sup>1</sup>	2009 3rd DAR <sup>1</sup>	\$ (d)=(c)-(b)	% (e)=(d)÷(b)	
	(a)	(b)	(c)			
<b>Demand Transmission Service</b>						
1	Interconnection	\$478.8	\$478.7	\$478.4	(\$0.3)	(0.1%)
2	Operating Reserve	145.5	145.9	145.9	(0.0)	(0.0%)
3	Voltage Control	53.6	52.8	52.8	-	-
4	Other System Support	7.7	8.0	8.0	(0.0)	(0.2%)
5	<b>Total DTS</b>	<b>\$685.6</b>	<b>\$685.5</b>	<b>\$685.2</b>	<b>(\$0.3)</b>	<b>(0.0%)</b>

Note: Numbers may not add due to rounding.

<sup>1</sup> DAR means Deferral Account Reconciliation.

- 297 The 2007 third reconciliation recorded revenue (excluding revenue related to losses) was \$685.2 million, which is \$0.3 million (or 0.04%) less than the second reconciliation recorded revenue of \$685.5 million.
- 298 On an annual basis, transmission revenue depends on approved transmission tariff rates, pool price, and billed volumes of demand and energy. Revenue variances after the first reconciliation generally arise due to billing adjustments, primarily reflecting changes to metered volumes such as those that occur in interim and final settlement. There were no significant variances between the second and third reconciliation recorded revenues for 2007.

#### 5.4 2007 Third Reconciliation Deferral Account Balance

- 299 Costs and revenue variances attributed to a year give rise to deferral account balances. The deferral account balances for the 2007 third reconciliation are summarized in Table 5-3, and reflect the 2007 third reconciliation costs and revenues provided in Table 5-1 and 5-2 respectively.
- 300 As noted in section 1.1 of this application, the AESO's tariff includes the use of deferral accounts, which were incorporated in the AESO's 2007 tariff through Working Capital Deficiency/Surplus Rider B and Deferral Account Adjustment Rider C. The AESO did not invoke Rider B during 2007, but determined Rider C charges and refunds in accordance with the rider's approved purpose to "restore deferral account balances to zero over the following calendar quarter". The AESO sets Rider C rates each quarter based on estimates of deferral account balances at the end of that quarter and forecast billing volumes for that quarter. Rider C charges and refunds attributed to 2007 are provided in column (d) of Table 5-3.
- 301 The second reconciliations of the 2007 deferral account in the AESO's 2008 deferral account reconciliation application resulted in a \$1.4 million shortfall attributed to 2007, as

*Table 5-3 2007 Third Reconciliation Deferral Account Summary (Excluding Losses), \$ 000 000*

Line No.	Recorded		Over	Prior Deferral Account		Net Over (Under)	
	Base Rate Revenue	Recorded Costs	(Under) Collection	Collections (Refunds) Rider C	DARs <sup>1</sup>	\$	%
	(a)	(b)	(c)=(a)+(b)	(d)	(e)	(f)=Σ(c):(e)	(g)=- (f)÷(b)
<b>Demand Transmission Service</b>							
1	Interconnection	\$478.4	(\$502.1)	(\$23.7)	\$34.1	(\$6.4)	\$3.9 0.8%
2	Operating Reserve	145.9	(183.3)	(37.4)	36.8	0.5	(0.0) (0.0%)
3	Voltage Control	52.8	(47.0)	5.8	(11.6)	5.3	(0.5) (1.0%)
4	Other System Support	8.0	(6.9)	1.1	(1.2)	0.1	(0.0) (0.2%)
5	<b>Total DTS</b>	<b>\$685.2</b>	<b>(\$739.3)</b>	<b>(\$54.2)</b>	<b>\$58.1</b>	<b>(\$0.5)</b>	<b>\$3.4 0.5%</b>

Note: Numbers may not add due to rounding.

<sup>1</sup> DAR means Deferral Account Reconciliation.

illustrated in Table 2-3 in section 2.3 of this application. The second reconciliation shortfall was collected from customers in the interim settlement in late June 2009 of the AESO's 2008 deferral account balances, which was approved on a final basis in Commission Decision 2009-191. Second reconciliation settlement amounts attributed to 2007 are included with first reconciliation settlement amounts in column (e) of Table 5-3, and restored all 2007 deferral account balances to zero based on the transactions included in the 2007 second reconciliation.

- 302 However, this third reconciliation includes adjustments to costs and revenues that occurred after the second reconciliation of the 2007 deferral account, as discussed in sections 5.2 and 5.3 where explanations were provided when the resulting line item variances were significant.
- 303 The interconnection charges deferral account balance has decreased to an overcollection of \$3.9 million (or 0.8% of recorded costs), primarily due to refunds to the AESO resulting from adjustments to transmission facility owner tariff and settlement of transmission deferral accounts for ATCO Electric and TransAlta, as discussed in section 5.2.1 above.
- 304 The voltage control charges deferral account balance has increased to an undercollection of \$0.5 million (or 1% of recorded costs) due to adjustments for unforeseeable TMR services in 2007.
- 305 Deferral account balances for operating reserve and other system support charges have not changed significantly from the first reconciliation.
- 306 The impact of all 2007 cost and revenue adjustments is a deferral account net balance increase to an overcollection of \$3.4 million (or 0.5% of recorded costs), compared to the zero balance that existed after settlement of amounts included in the second reconciliation.
- 307 Additional details on 2007 recorded costs and revenues are provided in Appendices B through G of this application. The allocation of the 2007 net deferral account balances to customers is discussed in section 9 of this application.

## 6 2006 FINANCIAL RESULTS AND DEFERRAL ACCOUNT BALANCE

308 The AESO's 2006 costs and revenues which are subject to retrospective deferral account reconciliation in this application are those related to wires, ancillary services, and the AESO's own administration (which includes other industry costs and general and administrative costs).

309 As discussed in section 2.1.2 of this application, effective January 1, 2006, transmission system losses are no longer subject to retrospective reconciliation. Since that time, Calibration Factor Rider E has adjusted loss factors for the recovery of the actual costs of losses on a prospective basis in accordance with section 33(1) of the *Transmission Regulation*. Therefore, the financial results and deferral account balance for 2006 discussed in this section do not include costs and revenues related to losses.

### 6.1 2006 Deferral Account Third Reconciliation

310 The AESO filed a first reconciliation of its 2006 deferral accounts as part of its 2004-2007 deferral account reconciliation application submitted to the Commission on June 2, 2008. The AESO subsequently filed a second reconciliation of its 2006 deferral accounts as part of its 2008 deferral account reconciliation application submitted to the Commission on April 9, 2009. That second reconciliation included all cost and revenue transactions (except those related to losses) that occurred from January 1, 2006, to December 31, 2008 and that related to 2006. The second reconciliation deferral account balance for 2006 was a surplus of \$2.0 million as provided in Table 2-3 in this application. The second reconciliation balance was settled with customers in June 2009 in accordance with the interim settlement of the AESO's 2008 deferral account reconciliation approved in Commission Decision 2009-074, released on June 3, 2009.

311 The second reconciliation resulted in \$702.3 million in costs and \$702.3 million in customer revenues (including Rider C collections and refunds as well as first and second reconciliation collections and refunds) being attributed to 2006.

312 In this 2009 deferral account reconciliation application, the third reconciliation for 2006 includes cost and revenue transactions (except those related to losses) that relate to 2006 and that occurred from January 1, 2006 to December 31, 2009. These transactions establish the 2006 production month data for third reconciliation purposes in this application. Compared to the second reconciliation, this third reconciliation includes additional transactions that relate to 2006 and that occurred after December 31, 2008 up to December 31, 2009.

313 The inclusion of these additional transactions decreases the 2006 recorded costs to \$700.9 million. The 2006 recorded revenue remained unchanged at \$702.3 million.

314 Revenue and cost transactions that occurred from January 1, 2006, to December 31, 2009 may also relate, in whole or in part, to years other than 2006. In such instances, the transaction (or part of the transaction) which relates to another year has been assigned to the relevant year, in accordance with the production month presentation described in

section 2.2 of this application. Detail on the assignment between 2006 and other years for transactions which occurred from 2006 to 2009 is provided in Appendix E-1 of this application.

## 6.2 2006 Cost Adjustments After Second Reconciliation

- 315 The AESO's 2006 revenue requirement (excluding losses) was approved in Alberta Energy and Utilities Board Order 2005-464 on the AESO's 2005-2006 General Tariff Application Second Refiling, released on December 20, 2005, and subsequently updated to incorporate the 2006 own costs update filed with the Board on January 13, 2006. The 2006 revenue requirement is provided as column (a) in Table 6-1. Variances of recorded costs from that approved forecast were explained in the first and second reconciliations of the 2006 deferral account (for those transactions included in those first and second reconciliations). First reconciliation variances were approved in Commission Decision 2009-010 on the AESO's 2004-2007 deferral account reconciliation released on January 27, 2009. Second reconciliation variances were approved in Commission Decision 2009-191 on the AESO's 2008 deferral account reconciliation released on October 29, 2009. No further discussion of those variances is provided in this application. Only 2006 cost adjustments which arise from transactions that occurred after the second reconciliation are discussed in this application.
- 316 Specifically, the 2006 cost adjustments (excluding those related to losses) which occurred after the first deferral account reconciliation and which are included in this second reconciliation are those transactions that:
- relate to 2006,
  - occurred after the cut-off date of December 31, 2008 for data included in the 2006 second reconciliation, and
  - occurred up to December 31, 2009.
- 317 These 2006 cost adjustments, together with the original 2006-related transactions which were included in the first and second reconciliations, establish the 2006 production year cost data for deferral account reconciliation purposes in this application.
- 318 Table 5-1 includes the following information for 2006:
- column (b) contains the 2006 recorded costs included in the second reconciliation in the 2008 application;
  - column (c) contains the 2006 recorded costs included in this application;
  - column (d) provides the additional amounts attributed to 2006 which occurred after the cut-off date for transactions included in the second reconciliation — that is, the cost variances between the second and third reconciliations; and
  - column (e) provides the 2006 additional amounts from column (d) as a percentage of the recorded costs from the second reconciliation in column (b).
- 319 As already discussed in the previous sections of this application, variances arise due to a number of factors, including finalization of TFO costs through Commission decisions, variances from forecast of volumes and pool price, delays and changes in AESO schedules

*Table 6-1 2006 Second and Third Reconciliation Cost Variances (Excluding Losses), \$ 000 000*

Line No.	Approved Forecast	Recorded Costs		Variance Over (Under)	
		2008 2nd DAR <sup>1</sup>	2009 3rd DAR <sup>1</sup>	\$ (d)=(c)-(b)	% (e)=(d)÷(b)
	(a)	(b)	(c)	(d)	(e)
<b>WIRES</b>					
<b>TFO Wires-Related Costs</b>					
1	AltaLink	193.7	189.0	187.5	(1.5) (0.8%)
2	ATCO Electric Ltd.	161.2	166.1	166.1	- -
3	Isolated Generation	(3.5)	(7.0)	(7.0)	- -
4	Subtotal ATCO Costs	157.7	159.2	159.2	- -
5	ENMAX Power Corporation	33.6	31.9	31.9	- -
6	EPCOR Transmission Inc.	32.8	36.9	36.9	- -
7	City of Lethbridge	4.5	4.2	4.2	- -
8	TransAlta	3.7	3.7	3.8	0.1 3.1%
9	Refund to the AESO	-	-	-	- -
10	Subtotal TransAlta Costs	3.7	3.7	3.8	0.1 3.1%
11	City of Red Deer	1.8	1.8	1.8	- -
12	FortisAlberta Networks (Farm)	1.9	1.5	1.5	- -
13	<b>Subtotal TFO Wires-Related Costs</b>	<b>429.8</b>	<b>428.1</b>	<b>426.7</b>	<b>(1.4) (0.3%)</b>
<b>Non-Wires Costs</b>					
14	Invitation to Bid on Credits (IBOC)	2.0	1.7	1.7	- -
15	Location Based Credit Standing Offer (LBC SO)	7.7	4.5	4.5	- -
16	<b>Subtotal IBOC/LBC SO Costs</b>	<b>9.7</b>	<b>6.2</b>	<b>6.2</b>	<b>- -</b>
17	<b>TOTAL WIRES COSTS</b>	<b>439.5</b>	<b>434.3</b>	<b>432.9</b>	<b>(1.4) (0.3%)</b>
<b>ANCILLARY SERVICES</b>					
<b>Operating Reserves</b>					
Active					
18	Regulating	24.8	47.1	47.1	- -
19	Spinning	25.6	63.4	63.4	- -
20	Supplemental	20.9	61.5	61.5	- -
21	<b>Subtotal Active Reserves</b>	<b>71.4</b>	<b>172.0</b>	<b>172.0</b>	<b>- -</b>
Standby					
22	Regulating	7.6	5.2	5.2	- -
23	Spinning	4.3	6.2	6.2	- -
24	Supplemental	2.1	2.5	2.5	- -
25	<b>Subtotal Standby Reserves</b>	<b>14.0</b>	<b>13.9</b>	<b>13.9</b>	<b>- -</b>
26	Trading Fees & Other Related Charges	-	(2.9)	(2.9)	- -
27	<b>Subtotal Operating Reserves</b>	<b>85.3</b>	<b>183.0</b>	<b>183.0</b>	<b>- -</b>
<b>Other Ancillary Services</b>					
28	Generator Remedial Action Schemes (RAS)	0.4	0.5	0.5	- -
29	Black Start	2.3	1.8	1.8	- -
30	Transmission Must-Run (TMR)	53.2	39.3	39.3	- -
31	Under Frequency Mitigation	6.9	5.6	5.6	- -
32	<b>Subtotal Other Ancillary Services</b>	<b>62.8</b>	<b>47.3</b>	<b>47.3</b>	<b>- -</b>

Table 6-1 2006 Second and Third Reconciliation Cost Variances (Excluding Losses), \$ 000 000  
(continued)

Line No.	Approved Forecast (a)	Recorded Costs		Variance Over (Under)		
		2008 2nd DAR <sup>1</sup> (b)	2009 3rd DAR <sup>1</sup> (c)	\$ (d)=(c)-(b)	% (e)=(d)÷(b)	
<b>Poplar Hill/ILRAS</b>						
33	Poplar Hill	1.9	2.0	2.0	-	-
34	Interruptible Load Remedial Action Scheme	0.5	0.8	0.8	(0.1)	(8.5%)
35	<b>Subtotal Poplar Hill/ILRAS</b>	<b>2.4</b>	<b>2.8</b>	<b>2.7</b>	<b>(0.1)</b>	<b>(2.5%)</b>
36	<b>TOTAL ANCILLARY SERVICES</b>	<b>150.6</b>	<b>233.0</b>	<b>233.0</b>	<b>(0.1)</b>	<b>(0.0%)</b>
<b>OTHER INDUSTRY COSTS</b>						
37	External Regulatory Costs	2.3	0.3	0.3	-	-
38	Western Electricity Coordinating Council (WECC)	1.4	1.3	1.3	-	-
39	Share of EUB Overhead	1.8	2.0	2.0	-	-
40	Balancing Pool	-	-	-	-	-
41	<b>TOTAL OTHER INDUSTRY COSTS</b>	<b>5.5</b>	<b>3.6</b>	<b>3.6</b>	<b>-</b>	<b>-</b>
<b>GENERAL AND ADMINISTRATIVE COSTS</b>						
<b>Administrative Costs</b>						
42	Staff and Benefits	20.8	20.1	20.1	-	-
43	Staff and Benefits Allocated to Capital	(0.9)	(0.7)	(0.7)	-	-
44	<b>Subtotal Staff and Benefits</b>	<b>19.9</b>	<b>19.4</b>	<b>19.4</b>	<b>-</b>	<b>-</b>
45	Consultants	2.1	2.9	2.9	-	-
46	Board Members Fees	0.4	0.4	0.4	-	-
47	Travel and Training	1.0	0.8	0.8	-	-
48	Legal	0.4	0.4	0.4	-	-
49	Accounting and Tax Advice	0.2	0.2	0.2	-	-
50	Rent <sup>2</sup>	1.5	1.4	1.4	-	-
51	Insurance	0.4	0.4	0.4	-	-
52	Other Administrative Costs	1.3	1.5	1.5	-	-
53	Telecomm and IT Maintenance	1.6	1.5	1.5	-	-
54	System Access Application Fees	-	(0.5)	(0.5)	-	-
55	<b>Total Administrative Costs</b>	<b>28.8</b>	<b>28.5</b>	<b>28.5</b>	<b>-</b>	<b>-</b>
<b>General Costs</b>						
56	Interest	0.5	(0.1)	(0.1)	-	-
57	Amortization and Depreciation	2.9	3.0	3.0	-	-
58	Taxes	-	-	-	-	-
59	<b>Total General Costs</b>	<b>3.4</b>	<b>2.9</b>	<b>2.9</b>	<b>-</b>	<b>-</b>
60	<b>TOTAL GENERAL &amp; ADMIN COSTS</b>	<b>32.2</b>	<b>31.4</b>	<b>31.4</b>	<b>-</b>	<b>-</b>
61	<b>Total G&amp;A and Other Industry Costs</b>	<b>37.7</b>	<b>35.0</b>	<b>35.0</b>	<b>-</b>	<b>-</b>
62	<b>TOTAL REVENUE REQUIREMENT</b>	<b>627.7</b>	<b>702.3</b>	<b>700.9</b>	<b>(1.5)</b>	<b>(0.2%)</b>

Table 6-1 2006 Second and Third Reconciliation Cost Variances (Excluding Losses), \$ 000 000  
(continued)

Line No.	Approved Forecast	Recorded Costs		Variance Over (Under)		
		2008 2nd DAR <sup>1</sup>	2009 3rd DAR <sup>1</sup>	\$	%	
	(a)	(b)	(c)	(d)=(c)-(b)	(e)=(d)÷(b)	
<b>CAPITAL</b>						
63	Salaries and Benefits	0.9	0.7	0.7	-	-
64	Other Capital	2.7	2.9	2.9	-	-
65	System Coordination Centre	11.6	11.9	11.9	-	-
66	<b>Total Capital</b>	<b>15.2</b>	<b>15.5</b>	<b>15.5</b>	-	-

Notes: Numbers may not add due to rounding.

Shaded numbers indicate significant variances which are discussed in the text.

<sup>1</sup> DAR means Deferral Account Reconciliation.

<sup>2</sup> Amortization of Rent Free Period not included in 2006 Recorded Costs on Line 50.

and priorities, and generally expected adjustments that occur over time. In the second reconciliation for 2006, in the 2008 deferral account reconciliation application, the AESO considered a line item variance to be significant when it exceeded  $\pm\$1.5$  million, or, if it was smaller than  $\pm\$1.5$  million, when it was both at least  $\pm\$0.15$  million and at least  $\pm 5\%$  of the approved line item amount.

320 In this third reconciliation for 2006, variances are represented by cost adjustments which occurred after the second reconciliation. It seems inappropriate to use the same threshold levels for variance explanations for adjustments as would be used in a second reconciliation. The AESO considers it reasonable to reduce the variance explanation thresholds by one-third, recognizing that costs may have varied from forecast in the first and second reconciliation and may also vary again due to further adjustments in this third reconciliation. Although each variance might be less than the first or second reconciliation threshold, together they may exceed it.

321 Therefore, in Table 6-1, the AESO considered a line item variance to be significant when it exceeded  $\pm\$1.0$  million, or, if it was smaller than  $\pm\$1.0$  million, when it was both at least  $\pm\$0.1$  million and at least  $\pm 3\%$  of the second reconciliation recorded costs item amount. Variances exceeding these thresholds are shaded in Table 5-1, with explanations provided by line number in the following discussion. Where variances were either less than  $\pm\$0.1$  million or less than  $\pm 3\%$  (except where such variance is  $\pm\$1.0$  million or greater) explanations are not provided, as such variances are considered small enough that specific variance explanations are not required.

### 6.2.1 Wires Costs

322 Recorded costs for TFO wires are based on actual billings by the TFOs to the AESO under final or interim tariffs or resulting from deferral account reconciliations or other adjustments approved for the TFOs. The 2006 second reconciliation recorded costs were based on actual billings by the TFOs to the AESO for 2006 up to December 31, 2008, which was the

data cut-off date for the AESO's 2008 deferral account reconciliation application. The third reconciliation recorded costs were similarly based on actual billings by the TFOs to the AESO for 2006 but up to December 31, 2009, which is the data cut-off date for this application.

#### **Line 1 AltaLink**

323 The 2006 third reconciliation recorded cost for AltaLink wires was \$187.5 million, which is \$1.5 million (or 1%) less than the second reconciliation recorded cost of \$189.0 million. The second reconciliation cost reflected billings resulting from Alberta Energy and Utilities Board Decision 2005-082, Order U2006-043, and Decision 2007-050 which approved AltaLink's 2006 transmission facility owner tariff on a final basis as well as adjustments to that tariff and deferral account settlements. The third reconciliation cost reflected an additional refund to the AESO of \$1.5 million resulting from Commission Decision 2009-018 on settlement of AltaLink's 2006 transmission deferral accounts pursuant to Commission Decision 2008-076.

#### **Line 8 TransAlta**

324 The 2006 third reconciliation recorded cost for TransAlta wires was \$3.8 million, which is \$0.1 million (or 3%) more than the second reconciliation recorded cost of \$3.7 million. The second reconciliation cost reflected billings resulting from Alberta Energy and Utilities Board Decision 2005-082 released July 28, 2005, which approved TransAlta's 2006 transmission facility owner tariff on a final basis. The third reconciliation cost included a charge to the AESO of \$0.1 million reflecting settlement of TransAlta's 2006 transmission deferral accounts included in Commission Decision 2009-151 on AltaLink's and TransAlta's 2009-2010 transmission facility owner tariffs.

#### **6.2.2 Ancillary Services**

325 The 2006 third reconciliation recorded costs for ancillary services were \$233.0 million, which is \$0.1 million (or 0.03%) less than the second reconciliation recorded costs of \$233.0 million, due to adjustments for interruptible load remedial action scheme (ILRAS) service as discussed in more detail below.

#### **Line 34 Interruptible Load Remedial Action Scheme (ILRAS)**

326 Interruptible load remedial action scheme (ILRAS) service supports the import capability of the Alberta-BC interconnection. If the Alberta-BC interconnection trips concurrent with high levels of import, the system will become generation deficient, system frequency will decline, and the AESO will be required to shed load quickly in Alberta to arrest the frequency decline and maintain system reliability. The AESO contracts for loads to automatically trip in these situations to limit the frequency decline and attempt to prevent shedding of additional system load. The 2006 third reconciliation recorded cost for ILRAS service was \$0.8 million, which is \$0.1 million (or 8%) less than the 2006 second reconciliation recorded cost of \$0.8 million due to finalization and settlement of outstanding collections under an ILRAS cost-sharing arrangement with the British Columbia Transmission Corporation that was terminated in 2009.

### 6.3 2006 Revenue Adjustments After Second Reconciliation

- 327 The AESO's 2006 forecast "base rate" revenue (excluding losses) was discussed in the 2004-2007 deferral account reconciliation application. Base rates exclude Deferral Account Adjustment Rider C, which collects or refunds revenue during the year to align actual revenue with actual costs by rate and rate component (excluding losses). The AESO does not forecast Rider C amounts as part of its tariff applications, and Rider C is therefore not included in this discussion of variances from forecast. Base rate revenue also excludes any amounts collected or refunded through deferral account reconciliation applications.
- 328 Variances of recorded base rate revenue from the 2006 first reconciliation were explained in the second reconciliation of the 2006 deferral account (for those transactions included in that second reconciliation). Those variances were approved in Commission Decision 2009-191 on the AESO's 2008 deferral account reconciliation released on October 29, 2009. No further discussion of those base rate revenue variances is provided in this application. Only revenue adjustments which arise from transactions that occurred after the second reconciliation are discussed in this application.
- 329 Specifically, the 2006 revenue adjustments (excluding those related to losses) which occurred after the second deferral account reconciliation and which are included in this third reconciliation are those transactions that:
- relate to 2006,
  - occurred after the cut-off date of December 31, 2008 for data included in the 2006 second reconciliation, and
  - occurred up to December 31, 2009.
- 330 These 2006 revenue adjustments, together with the 2006-related transactions which were included in the first and second reconciliations, establish the 2006 production year revenue data for deferral account reconciliation purposes in this application.
- 331 Table 6-2 accordingly includes the following information for 2006:
- column (b) contains the 2006 recorded base rate revenue included in the second reconciliation in the 2008 application;
  - column (c) contains the 2006 recorded base rate revenue included in this application;
  - column (d) provides the additional base rate revenue amounts attributed to 2006 which occurred after the cut-off date for transactions included in the second reconciliation — that is, the revenue variances between the second and third reconciliations; and
  - column (e) provides the 2006 additional revenue amounts from column (d) as a percentage of the recorded revenue from the first reconciliation in column (b).
- 332 The 2006 third reconciliation recorded base rate revenue (excluding revenue related to losses) was \$700.6 million, which is the same as the second reconciliation recorded revenue.
- 333 On an annual basis, transmission revenue depends on approved transmission tariff rates, pool price, and billed volumes of demand and energy. Revenue variances after the second

Table 6-2 2006 Second and Third Reconciliation Revenue Variances (Excluding Losses),  
\$ 000 000

Line No.	Forecast Revenue (a)	Recorded Revenue		Variance Over (Under)	
		2008 2nd DAR <sup>1</sup> (b)	2009 3rd DAR <sup>1</sup> (c)	\$ (d)=(c)-(b)	% (e)=(d)÷(b)
<b>Demand Transmission Service</b>					
1	Interconnection	\$478.8	\$467.0	\$467.0	\$0.0 0.0%
2	Operating Reserve	88.1	173.5	173.4	(0.0) (0.0%)
3	Voltage Control	53.2	52.3	52.3	0.0 0.0%
4	Other System Support	8.7	7.9	7.9	(0.0) (0.0%)
5	<b>Total DTS</b>	<b>\$628.8</b>	<b>\$700.6</b>	<b>\$700.6</b>	<b>\$0.0 0.0%</b>

Note: Numbers may not add due to rounding.

<sup>1</sup> DAR means Deferral Account Reconciliation.

reconciliation generally arise due to billing adjustments, primarily reflecting changes to metered volumes such as those that occur in post-final adjustments. There were no significant variances between the second and third reconciliation recorded revenues for 2006.

#### 6.4 2006 Third Reconciliation Deferral Account Balance

334 Costs and revenue variances attributed to a year give rise to deferral account balances. The deferral account balances for the 2006 third reconciliation are summarized in Table 6-3, and reflect the 2006 third reconciliation costs and revenues provided in Table 6-1 and 6-2 respectively.

335 As noted in section 1.1 of this application, the AESO's tariff includes the use of deferral accounts, which were incorporated in the AESO's 2006 tariff through Working Capital Deficiency/Surplus Rider B and Deferral Account Adjustment Rider C. The AESO did not invoke Rider B during 2006, but determined Rider C charges and refunds in accordance with the rider's approved purpose to "restore deferral account balances to zero over the following calendar quarter". The AESO sets Rider C rates each quarter based on estimates of deferral account balances at the end of that quarter and forecast billing volumes for that quarter. Rider C charges and refunds attributed to 2006 are provided in column (d) of Table 6-3.

336 The second reconciliation of the 2006 deferral account in the AESO's 2008 deferral account reconciliation application resulted in a \$2.0 million surplus attributed to 2006, as illustrated in Table 2-3 in section 2.3 of this application. The second reconciliation surplus was refunded to customers in the interim settlement in late June 2009 of the AESO's 2008 deferral account balances, which was approved on a final basis in Commission Decision 2009-191. Second reconciliation settlement amounts attributed to 2006 are included with first

*Table 6-3 2006 Third Reconciliation Deferral Account Summary (Excluding Losses), \$ 000 000*

Line No.	Recorded Base Rate Revenue	Recorded Costs	Over (Under) Collection	Prior Deferral Account Collections (Refunds)		Net Over (Under) Collection Variance	
				Rider C	DARs <sup>1</sup>	\$	%
	(a)	(b)	(c)=(a)+(b)	(d)	(e)	(f)=Σ(c):(e)	(g)=- (f)÷(b)
<b>Demand Transmission Service</b>							
1	Interconnection	\$467.0	(\$468.6)	(\$1.7)	\$14.5	(\$11.3)	\$1.5 0.3%
2	Operating Reserve	173.4	(185.3)	(11.9)	13.3	(1.4)	(0.0) (0.0%)
3	Voltage Control	52.3	(39.3)	13.0	(12.4)	(0.5)	0.0 0.0%
4	Other System Support	7.9	(7.6)	0.4	(0.3)	(0.1)	(0.0) (0.0%)
5	<b>Total DTS</b>	<b>\$700.6</b>	<b>(\$700.9)</b>	<b>(\$0.2)</b>	<b>\$15.1</b>	<b>(\$13.4)</b>	<b>\$1.5 0.2%</b>

Notes: Numbers may not add due to rounding.

<sup>1</sup> DAR means Deferral Account Reconciliation.

reconciliation settlement amounts in column (e) of Table 6-3, and restored all 2006 deferral account balances to zero based on the transactions included in the 2006 second reconciliation.

- 337 However, this third reconciliation includes adjustment to costs and revenues that occurred after the second reconciliation of the 2006 deferral account, as discussed in sections 6.2 and 6.3 where explanations were provided when the resulting line item variances were significant.
- 338 The interconnection charge deferral account balance has decreased to an overcollection of \$1.5 million (or 0.3% of recorded costs) due to the settlements of 2006 transmission deferral accounts for AltaLink and TransAlta discussed in section 6.2.1.
- 339 The deferral account balances for operating reserve charge, voltage control charge, and other system support charge have not changed significantly from the second reconciliation.
- 340 The impact of all 2006 cost and revenue adjustments is a deferral account net balance decrease to an overcollection of \$1.5 million (or 0.2% of recorded costs), compared to the zero balance that existed after settlement of amounts included in the second reconciliation.
- 341 Additional details on 2006 recorded costs and revenues are provided in Appendices B through G of this application. The allocation of the 2006 net deferral account balances to customers is discussed in section 9 of this application.

## **7 2005 FINANCIAL RESULTS AND DEFERRAL ACCOUNT BALANCE**

342 The AESO's 2005 costs and revenues which are subject to retrospective deferral account reconciliation in this application are those related to wires, ancillary services, losses, and the AESO's own administration (which includes other industry costs and general and administrative costs).

### **7.1 2005 Deferral Account Third Reconciliation**

343 The AESO filed a first reconciliation of its 2005 deferral accounts as part of its 2004-2007 deferral account reconciliation application submitted to the Commission on June 2, 2008. The AESO subsequently filed a second reconciliation of its 2005 deferral accounts as part of its 2008 deferral account reconciliation application submitted to the Commission on April 9, 2009. That second reconciliation included all cost and revenue transactions that occurred from January 1, 2005, to December 31, 2008 and that related to 2005. The second reconciliation deferral account balance for 2005 was a surplus of \$1.4 million as provided in Table 2-3 in this application. The second reconciliation balance was settled with customers in June 2009 in accordance with the interim settlement of the AESO's 2008 deferral account reconciliation application approved in Commission Decision 2009-074, released on June 3, 2009.

344 The second reconciliation resulted in \$850.1 million in costs and \$850.1 million in customer revenues (including Rider C collections and refunds as well as first and second reconciliation collections and refunds) being attributed to 2005.

345 In this 2009 deferral account reconciliation application, the third reconciliation for 2005 includes all cost and revenue transactions that relate to 2005 and that occurred from January 1, 2005 to December 31, 2009. These transactions establish the 2005 production month data for third reconciliation purposes in this application. Compared to the second reconciliation, this third reconciliation includes additional transactions that relate to 2005 and that occurred after December 31, 2008 up to December 31, 2009.

346 The inclusion of these additional transactions increases the 2005 recorded costs to \$850.2 million. The 2005 recorded revenue remained unchanged at \$850.1 million.

347 Revenue and cost transactions that occurred from January 1, 2005, to December 31, 2009 may also relate, in whole or in part, to years other than 2005. In such instances, the transaction (or part of the transaction) which relates to another year has been assigned to the relevant year, in accordance with the production month presentation described in section 2.2 of this application. Detail on the assignment between 2005 and other years for transactions which occurred from 2005 to 2009 is provided in Appendix E-1 of this application.

348 The AESO also notes that, as discussed in section 2.1.2 of this application, effective January 1, 2006, transmission system losses are no longer subject to retrospective deferral account reconciliation, and were therefore not included in sections 3, 4, 5, and 6 of this application relating to 2009, 2008, 2007, and 2006 respectively. However, transmission

system losses were subject to retrospective deferral account reconciliation in 2005 and prior years, and are therefore included in this section relating to 2005.

## 7.2 2005 Cost Adjustments After Second Reconciliation

- 349 The AESO's 2005 revenue requirement was approved in Alberta Energy and Utilities Board Order 2005-464 on the AESO's 2005-2006 General Tariff Application Second Refiling, released on December 20, 2005, and is provided as column (a) in Table 7-1. Variances of recorded costs from that approved forecast were explained in the first and second reconciliations of the 2005 deferral account (for those transactions included in those first and second reconciliations). First reconciliation variances were approved in Commission Decision 2009-010 on the AESO's 2004-2007 Deferral Account Reconciliation released on January 27, 2009. Second reconciliation variances were approved in Commission Decision 2009-191 on the AESO's 2008 Deferral Account Reconciliation released on October 29, 2009. No further discussion of those variances is provided in this application. Only 2005 cost adjustments which arise from transactions that occurred after the second reconciliation are discussed in this application.
- 350 Specifically, the 2005 cost adjustments which occurred after the second deferral account reconciliation and which are included in this third reconciliation are those transactions that:
- relate to 2005,
  - occurred after the cut-off date of December 31, 2008 for data included in the 2005 second reconciliation, and
  - occurred up to December 31, 2009.
- 351 These 2005 cost adjustments, together with the original 2005-related transactions which were included in the first and second reconciliations, establish the 2005 production year cost data for deferral account reconciliation purposes in this application.
- 352 Table 7-1 includes the following information for 2005:
- column (b) contains the 2005 recorded costs included in the second reconciliation in the 2008 application;
  - column (c) contains the 2005 recorded costs included in this application;
  - column (d) provides the additional amounts attributed to 2005 which occurred after the cut-off date for transactions included in the second reconciliation — that is, the cost variances between the second and third reconciliations; and
  - column (e) provides the 2005 additional amounts from column (d) as a percentage of the recorded costs from the second reconciliation in column (b).
- 353 As already discussed in the previous sections of this application, variances arise due to a number of factors, including finalization of TFO costs through Commission decisions, variances from forecast of volumes and pool price, delays and changes in AESO schedules and priorities, and generally expected adjustments that occur over time. In the second reconciliation for 2005, in the 2008 deferral account reconciliation application, the AESO considered a line item variance to be significant when it exceeded  $\pm$ \$1.5 million, or, if it was

Table 7-1 2005 Second and Third Reconciliation Cost Variances, \$ 000 000

Line No.	Approved Forecast	Recorded Costs		Variance Over (Under)	
		2008 2nd DAR <sup>1</sup>	2009 3rd DAR <sup>1</sup>	\$ (d)=(c)-(b)	% (e)=(d)÷(b)
	(a)	(b)	(c)	(d)	(e)
<b>WIRES</b>					
<b>TFO Wires-Related Costs</b>					
1	AltaLink	181.5	182.1	182.2	0.1 0.0%
2	ATCO Electric Ltd.	161.2	163.7	163.7	- -
3	Isolated Generation	(5.5)	(5.9)	(5.9)	- -
4	Subtotal ATCO Costs	155.7	157.8	157.8	- -
5	ENMAX Power Corporation	33.6	34.1	34.1	- -
6	EPCOR Transmission Inc.	35.2	37.1	37.1	- -
7	City of Lethbridge	4.5	4.5	4.5	- -
8	TransAlta	3.6	3.6	3.5	(0.1) (2.9%)
9	Refund to the AESO	n/a	n/a	n/a	n/a n/a
10	Subtotal TransAlta Costs	3.6	3.6	3.5	(0.1) (2.9%)
11	City of Red Deer	1.8	1.8	1.8	- -
12	FortisAlberta Networks (Farm)	1.9	1.9	1.9	- -
13	Subtotal TFO Wires-Related Costs	417.8	422.8	422.8	(0.0) (0.0%)
<b>Non-Wires Costs</b>					
14	Invitation to Bid on Credits (IBOC)	1.9	1.7	1.7	- -
15	Location Based Credit Standing Offer (LBC SO)	7.5	4.1	4.1	- -
16	Subtotal IBOC/LBC SO Costs	9.4	5.9	5.9	- -
17	TOTAL WIRES COSTS	427.2	428.7	428.7	(0.0) (0.0%)
<b>ANCILLARY SERVICES</b>					
<b>Operating Reserves</b>					
Active					
18	Regulating	27.0	38.6	38.6	- -
19	Spinning	29.2	44.1	44.1	- -
20	Supplemental	15.1	30.9	30.9	- -
21	Subtotal Active Reserves	71.3	113.5	113.5	- -
Standby					
22	Regulating	4.2	3.6	3.6	- -
23	Spinning	7.0	5.2	5.2	- -
24	Supplemental	1.9	2.2	2.2	- -
25	Subtotal Standby Reserves	13.1	10.9	10.9	- -
26	Trading Fees & Other Related Charges	-	(2.2)	(2.2)	- -
27	Subtotal Operating Reserves	84.4	122.2	122.2	- -
<b>Other Ancillary Services</b>					
28	Generator Remedial Action Schemes (RAS)	0.4	0.5	0.5	- -
29	Black Start	2.3	1.6	1.6	- -
30	Transmission Must Run (TMR)	41.4	56.2	56.4	0.2 0.4%
31	Under Frequency Mitigation	6.5	6.3	6.3	- -
32	Subtotal Other Ancillary Services	50.6	64.6	64.8	0.2 0.4%

Table 7-1 2005 Second and Third Reconciliation Cost Variances, \$ 000 000 (continued)

Line No.	Approved Forecast	Recorded Costs		Variance Over (Under)	
		2008 2nd DAR <sup>1</sup>	2009 3rd DAR <sup>1</sup>	\$ (d)=(c)-(b)	% (e)=(d)÷(b)
	(a)	(b)	(c)	(d)=(c)-(b)	(e)=(d)÷(b)
<b>Poplar Hill/ILRAS</b>					
33	Poplar Hill	1.9	1.9	1.9	-
34	Interruptible Load Remedial Action Scheme	0.8	0.9	0.8	(0.1) (7.8%)
35	<b>Subtotal Poplar Hill/ILRAS</b>	<b>2.7</b>	<b>2.8</b>	<b>2.8</b>	<b>(0.1) (2.6%)</b>
36	<b>TOTAL ANCILLARY SERVICES</b>	<b>137.7</b>	<b>189.7</b>	<b>189.8</b>	<b>0.1 0.1%</b>
<b>LOSSES</b>					
37	Pool Payment	181.0	196.1	196.1	-
38	Prior Year Losses Adjustments	-	-	-	-
39	One-time Settlement Data Adjustment	-	-	-	-
40	<b>TOTAL LOSSES COSTS</b>	<b>181.0</b>	<b>196.1</b>	<b>196.1</b>	<b>-</b>
<b>OTHER INDUSTRY COSTS</b>					
41	External Regulatory Costs	5.0	2.7	2.7	-
42	Western Electricity Coordinating Council (WECC)	1.0	0.8	0.8	-
43	Share of EUB Overhead	1.8	1.8	1.8	-
44	Balancing Pool	-	-	-	-
45	<b>TOTAL OTHER INDUSTRY COSTS</b>	<b>7.8</b>	<b>5.3</b>	<b>5.3</b>	<b>-</b>
<b>GENERAL AND ADMINISTRATIVE COSTS</b>					
<b>Administrative Costs</b>					
46	Staff and Benefits	19.2	19.7	19.7	-
47	Consultants	2.6	2.6	2.6	-
48	Board Members Fees	0.3	0.4	0.4	-
49	Travel and Training	1.0	0.8	0.8	-
50	Legal	0.4	0.6	0.6	-
51	Accounting and Tax Advice	0.3	0.2	0.2	-
52	Rent <sup>2</sup>	1.2	1.2	1.2	-
53	Insurance	0.5	0.4	0.4	-
54	Other Administrative Costs	2.6	2.4	2.4	-
55	Interconnection Fees (Offset)	(0.9)	(0.6)	(0.6)	-
56	<b>Total Administrative Costs</b>	<b>27.2</b>	<b>27.7</b>	<b>27.7</b>	<b>-</b>

Table 7-1 2005 Second and Third Reconciliation Cost Variances, \$ 000 000 (continued)

Line No.	Approved Forecast	Recorded Costs		Variance Over (Under)		
		2008 2nd DAR <sup>1</sup>	2009 3rd DAR <sup>1</sup>	\$ (d)=(c)-(b)	% (e)=(d)÷(b)	
	(a)	(b)	(c)	(d)=(c)-(b)	(e)=(d)÷(b)	
<b>General Costs</b>						
57	Interest	0.3	0.4	0.4	-	-
58	Amortization and Depreciation	1.7	2.3	2.3	-	-
59	Taxes	-	-	-	-	-
60	<b>Total General Costs</b>	<b>2.0</b>	<b>2.6</b>	<b>2.6</b>	-	-
61	<b>TOTAL GENERAL &amp; ADMIN COSTS</b>	<b>29.2</b>	<b>30.3</b>	<b>30.3</b>	-	-
62	<b>Total G&amp;A and Other Industry Costs</b>	<b>37.0</b>	<b>35.7</b>	<b>35.7</b>	-	-
63	<b>TOTAL REVENUE REQUIREMENT</b>	<b>782.9</b>	<b>850.1</b>	<b>850.2</b>	<b>0.1</b>	<b>0.0%</b>
64	<b>CAPITAL</b>	<b>4.5</b>	<b>5.9</b>	<b>5.9</b>	-	-

Notes: Numbers may not add due to rounding.

Shaded numbers indicate significant variances which are discussed in the text.

<sup>1</sup> DAR means Deferral Account Reconciliation.

<sup>2</sup> Amortization of Rent Free Period not included in 2005 Recorded Costs on Line 52.

smaller than  $\pm\$1.5$  million, when it was both at least  $\pm\$0.15$  million and at least  $\pm 5\%$  of the approved line item amount.

354 In this third reconciliation for 2005, variances are represented by cost adjustments which occurred after the second reconciliation. It seems inappropriate to use the same threshold levels for variance explanations for adjustments as would be used in a second reconciliation. The AESO considers it reasonable to reduce the variance explanation thresholds by one-third, recognizing that costs may have varied from forecast in the first and second reconciliations and may also vary again due to further adjustments in this third reconciliation. Although each variance might be less than the first or second reconciliation threshold, together they may exceed it.

355 Therefore, in Table 7-1, the AESO considered a line item variance to be significant when it exceeded  $\pm\$1.0$  million, or, if it was smaller than  $\pm\$1.0$  million, when it was both at least  $\pm\$0.1$  million and at least  $\pm 3\%$  of the second reconciliation recorded costs line item amount. Variances exceeding these thresholds are shaded in Table 7-1, with explanations provided by line number in the following discussion. Where variances were either less than  $\pm\$0.1$  million or less than  $\pm 3\%$  (except where such variance is  $\pm\$1.0$  million or greater) explanations are not provided, as such variances are considered small enough that specific variance explanations are not required.

### 7.2.1 Wires Costs

356 Recorded costs for TFO wires are based on actual billings by the TFOs to the AESO under final or interim tariffs or resulting from deferral account reconciliations or other adjustments approved for the TFOs. The 2005 second reconciliation recorded costs were based on actual billings by the TFOs to the AESO for 2005 up to December 31, 2008, which was the data cut-off date for the AESO's 2008 deferral account reconciliation application. The third reconciliation recorded costs were similarly based on actual billings by the TFOs to the AESO for 2005 but up to December 31, 2009, which is the data cut-off date for this application.

#### Line 8 TransAlta

357 The 2005 third reconciliation recorded cost for TransAlta wires was \$3.5 million, which is \$0.1 million (or 3%) less than the second reconciliation recorded cost of \$3.6 million. The second reconciliation cost reflected billings resulting from Alberta Energy and Utilities Board Decision 2005-082 released July 28, 2005, which approved TransAlta's 2006 transmission facility owner tariff on a final basis. The third reconciliation cost included a refund to the AESO of \$0.1 million reflecting settlement of TransAlta's 2005 transmission deferral accounts included in Commission Decision 2009-151 on AltaLink's and TransAlta's 2009-2010 transmission facility owner tariffs.

### 7.2.2 Ancillary Services

358 The 2005 third reconciliation recorded costs for ancillary services were \$189.8 million, which is \$0.1 million (or 0.1%) more than the second reconciliation recorded costs of \$189.7 million, due to payments for transmission must-run service offset by collections for interruptible load remedial action scheme ("ILRAS") service as discussed in more detail below.

#### Lines 30 Transmission Must-Run ("TMR") Service

359 TMR is generation required to be on-line and operating at specific levels in particular parts of the AES in order to ensure system security. The majority of TMR service is foreseeable, which the AESO generally procures through a competitive procedure resulting in commercial agreements between the AESO and TMR suppliers. When the TMR service is unforeseeable, the AESO may conscript and pay suppliers under the methodology detailed in Article 11 of the AESO's tariff.

360 The 2005 third reconciliation recorded TMR cost was \$56.4 million, which is \$0.2 million (or 0.4%) more than the second reconciliation recorded cost of \$56.2 million. The increase was due to finalization of a review of costs for unforeseeable TMR service under the compensation methodology to be retrospectively applied to the period December 17, 2004 until February 12, 2008, according to the terms of the AESO's Ancillary Services Article 11 Negotiated Settlement approved in Commission Decision 2008-014 released on February 12, 2008. The AESO believes that as of December 31, 2009, no costs for unforeseeable TMR service remain outstanding with respect to 2005.

#### Line 34 Interruptible Load Remedial Action Scheme (ILRAS)

361 Interruptible load remedial action scheme (ILRAS) service supports the import capability of the Alberta-BC interconnection. If the Alberta-BC interconnection trips concurrent with high

levels of import, the system will become generation deficient, system frequency will decline, and the AESO will be required to shed load quickly in Alberta to arrest the frequency decline and maintain system reliability. The AESO contracts for loads to automatically trip in these situations to limit the frequency decline and attempt to prevent shedding of additional system load. The 2005 third reconciliation recorded cost for ILRAS service was \$0.8 million, which is \$0.1 million (or 8%) less than the 2005 second reconciliation recorded cost of \$0.9 million due to finalization and settlement of outstanding collections under an ILRAS cost-sharing arrangement with the British Columbia Transmission Corporation that was terminated in 2009.

### 7.3 2005 Revenue Adjustments After Second Reconciliation

- 362 The AESO's 2005 forecast "base rate" revenue was discussed in the 2004-2007 deferral account reconciliation application. Base rates exclude Deferral Account Adjustment Rider C, which collects or refunds revenue during the year to align actual revenue with actual costs by rate and rate component. The AESO does not forecast Rider C amounts as part of its tariff applications, and Rider C is therefore not included in this discussion of variances from forecast. Base rate revenue also excludes any amounts collected or refunded through deferral account reconciliation applications.
- 363 Variances of recorded base rate revenue from the 2005 first reconciliation were explained in the second reconciliation of the 2005 deferral account (for those transactions included in that second reconciliation). Those variances were approved in Commission Decision 2009-191 on the AESO's 2008 deferral account reconciliation released on October 29, 2009. No further discussion of those base rate revenue variances is provided in this application. Only revenue adjustments which arise from transactions that occurred after the second reconciliation are discussed in this application.
- 364 Specifically, the 2005 revenue adjustments which occurred after the second deferral account reconciliation and which are included in this third reconciliation are those transactions that:
- relate to 2005,
  - occurred after the cut-off date of December 31, 2008 for data included in the 2005 second reconciliation, and
  - occurred up to December 31, 2009.
- 365 These 2005 revenue adjustments, together with the 2005-related transactions which were included in the first and second reconciliations, establish the 2005 production year revenue data for deferral account reconciliation purposes in this application.
- 366 Table 7-2 accordingly includes the following information for 2005:
- column (b) contains the 2005 recorded base rate revenue included in the second reconciliation in the 2008 application;
  - column (c) contains the 2005 recorded base rate revenue included in this application;

Table 7-2 2005 Second and Third Reconciliation Revenue Variances, \$ 000 000

Line No.	Forecast Revenue	Recorded Revenue		Variance Over (Under)		
		2008 2nd DAR <sup>1</sup>	2009 3rd DAR <sup>1</sup>	\$ (d)=(c)-(b)	% (e)=(d)÷(b)	
	(a)	(b)	(c)	(d)=(c)-(b)	(e)=(d)÷(b)	
<b>Demand Transmission Service</b>						
1	Interconnection	\$257.6	\$258.7	\$258.7	-	-
2	Operating Reserve	92.9	110.7	110.7	-	-
3	Other System Support	2.5	2.4	2.4	-	-
4	<b>Total DTS</b>	<b>\$353.0</b>	<b>\$371.8</b>	<b>\$371.8</b>	<b>-</b>	<b>-</b>
<b>Supply Transmission Service</b>						
5	Interconnection	\$178.5	\$172.8	\$172.8	-	-
6	Losses	185.5	180.7	180.7	-	-
7	Operating Reserve	94.8	106.5	106.5	-	-
8	<b>Total STS</b>	<b>\$458.8</b>	<b>\$460.1</b>	<b>\$460.1</b>	<b>-</b>	<b>-</b>
<b>Total DTS and STS</b>						
9	Interconnection	\$436.0	\$431.5	\$431.5	-	-
10	Losses	185.5	180.7	180.7	-	-
11	Operating Reserve	187.7	217.3	217.3	-	-
12	Other System Support	2.5	2.4	2.4	-	-
13	<b>Total DTS and STS</b>	<b>\$811.8</b>	<b>\$831.9</b>	<b>\$831.9</b>	<b>-</b>	<b>-</b>

Note: Numbers may not add due to rounding.

<sup>1</sup> DAR means Deferral Account Reconciliation.

- column (d) provides the additional base rate revenue amounts attributed to 2005 which occurred after the cut-off date for transactions included in the second reconciliation — that is, the revenue variances between the second and third reconciliations; and
- column (e) provides the 2005 additional revenue amounts from column (d) as a percentage of the recorded revenue from the second reconciliation in column (b).

367 The 2005 third reconciliation recorded base rate revenue was \$831.9 million, which is the same as the second reconciliation recorded revenue.

368 On an annual basis, transmission revenue depends on approved transmission tariff rates, pool price, and billed volumes of demand and energy. Revenue variances after the second reconciliation generally arise due to billing adjustments, primarily reflecting changes to metered volumes such as those that occur in post-final adjustments. There were no variances between the second and third reconciliation recorded revenues for 2005.

#### 7.4 2005 Third Reconciliation Deferral Account Balance

- 369 Costs and revenue variances attributed to a year give rise to deferral account balances. The deferral account balances for the 2005 third reconciliation are summarized in Table 7-3, and reflect the 2005 third reconciliation costs and revenues provided in Table 7-1 and 7-2 respectively.
- 370 As noted in section 1.1 of this application, the AESO's tariff includes the use of deferral accounts, which were incorporated in the AESO's 2005 tariff through Working Capital Deficiency/Surplus Rider B and Deferral Account Adjustment Rider C. The AESO did not invoke Rider B during 2005, but determined Rider C charges and refunds in accordance with the rider's approved purpose to "restore deferral account balances to zero over the following calendar quarter". The AESO sets Rider C rates each quarter based on estimates of deferral account balances at the end of that quarter and forecast billing volumes for that quarter. Rider C charges and refunds attributed to 2005 are provided in column (d) of Table 7-3.
- 371 The second reconciliation of the 2005 deferral account in the AESO's 2008 deferral account reconciliation application resulted in a \$1.4 million surplus attributed to 2005, as illustrated in Table 2-3 in section 2.3 of this application. The second reconciliation shortfall was refunded to customers in the interim settlement in late June 2009 of the AESO's 2008 deferral account balances, which was approved on a final basis in Commission Decision 2009-191. Second reconciliation settlement amounts attributed to 2005 are included with first reconciliation settlement amounts in column (e) of Table 7-3, and restored all 2005 deferral account balances to zero based on the transactions included in the 2005 second reconciliation.
- 372 However, this third reconciliation includes adjustment to costs and revenues that occurred after the second reconciliation of the 2005 deferral account, as discussed in sections 7.2 and 7.3 where explanations were provided when the resulting line item variances were significant.
- 373 There were no significant changes to 2005 deferral account balances for individual rate component charges compared to the second reconciliation.
- 374 The impact of all 2005 cost and revenue adjustments is a deferral account net balance increase to an undercollection of \$0.1 million (or 0.01% of recorded costs), compared to the zero balance that existed after settlement of amounts included in the second reconciliation.
- 375 Additional details on 2005 recorded costs and revenues are provided in Appendices B through G of this application. The allocation of the 2005 net deferral account balances to customers is discussed in section 9 of this application.

Table 7-3 2005 Third Reconciliation Deferral Account Summary, \$ 000 000

Line No.	Recorded	Over (Under)	Prior Deferral Account Collections (Refunds)	Net Over (Under) Collection Variance				
	Base Rate Revenue (a)			Recorded Costs (b)	Rider C (d)	DARs <sup>1</sup> (e)	\$ (f)=Σ(c):(e)	% (g)=-:(f)÷:(b)
<b>Demand Transmission Service</b>								
1	Interconnection	\$258.7	(\$269.6)	(\$10.9)	\$6.0	\$4.9	\$0.0	0.0%
2	Operating Reserve	110.7	(93.5)	17.2	(15.9)	(1.4)	(0.1)	(0.1%)
3	Other System Support	2.4	(2.4)	(0.1)	0.6	(0.6)	0.0	1.7%
4	<b>Total DTS</b>	<b>\$371.8</b>	<b>(\$365.6)</b>	<b>\$6.2</b>	<b>(\$9.2)</b>	<b>\$3.0</b>	<b>(\$0.0)</b>	<b>(0.0%)</b>
<b>Supply Transmission Service</b>								
5	Interconnection	\$172.8	(\$195.0)	(\$22.2)	\$17.8	\$4.4	\$0.0	0.0%
6	Losses	180.7	(196.1)	(15.4)	22.8	(7.4)	0.0	0.0%
7	Operating Reserve	106.5	(93.5)	13.0	(12.7)	(0.4)	(0.1)	(0.1%)
8	<b>Total STS</b>	<b>\$460.1</b>	<b>(\$484.7)</b>	<b>(\$24.5)</b>	<b>\$27.9</b>	<b>(\$3.4)</b>	<b>(\$0.1)</b>	<b>(0.0%)</b>
<b>Total DTS and STS</b>								
9	Interconnection	\$431.5	(\$464.6)	(\$33.1)	\$23.9	\$9.3	\$0.1	0.0%
10	Losses	180.7	(196.1)	(15.4)	22.8	(7.4)	0.0	0.0%
11	Operating Reserve	217.3	(187.1)	30.2	(28.6)	(1.8)	(0.2)	(0.1%)
12	Other System Support	2.4	(2.4)	(0.1)	0.6	(0.6)	0.0	1.7%
13	<b>Total DTS and STS</b>	<b>\$831.9</b>	<b>(\$850.2)</b>	<b>(\$18.3)</b>	<b>\$18.7</b>	<b>(\$0.4)</b>	<b>(\$0.1)</b>	<b>(0.0%)</b>

Note: Numbers may not add due to rounding.

<sup>1</sup> DAR means Deferral Account Reconciliation.

## **8 2004 FINANCIAL RESULTS AND DEFERRAL ACCOUNT BALANCE**

376 The AESO's 2004 costs and revenues which are subject to retrospective deferral account reconciliation in this application are those related to wires, ancillary services, losses, and the AESO's own administration (which includes other industry costs and general and administrative costs).

### **8.1 2004 Deferral Account Third Reconciliation**

377 The AESO filed a first reconciliation of its 2004 deferral accounts as part of its 2004-2007 deferral account reconciliation application submitted to the Commission on June 2, 2008. The AESO subsequently filed a second reconciliation of its 2004 deferral accounts as part of its 2008 deferral account reconciliation application submitted to the Commission on April 9, 2009. That second reconciliation included all cost and revenue transactions that occurred from January 1, 2004, to December 31, 2008 and that related to 2004. The second reconciliation deferral account balance for 2004 was a surplus of \$0.1 million as provided in Table 2-3 in this application. The second reconciliation balance was settled with customers in June 2009 in accordance with the interim settlement of the AESO's 2008 deferral account reconciliation application approved in Commission Decision 2009-074, released on June 3, 2009.

378 The second reconciliation resulted in \$691.0 million in costs and \$691.0 million in customer revenues (including Rider C collections and refunds as well as first and second reconciliation collections and refunds) being attributed to 2004.

379 In this 2009 deferral account reconciliation application, the third reconciliation for 2004 includes all cost and revenue transactions that relate to 2004 and that occurred from January 1, 2004 to December 31, 2009. These transactions establish the 2004 production month data for third reconciliation purposes in this application. Compared to the second reconciliation, this third reconciliation includes additional transactions that relate to 2004 and that occurred after December 31, 2008 up to December 31, 2009.

380 The inclusion of these additional transactions increases the 2004 recorded costs to \$691.3 million. The 2004 recorded revenue remained unchanged at \$691.0 million.

381 Revenue and cost transactions that occurred from January 1, 2004, to December 31, 2009 may also relate, in whole or in part, to years other than 2004. In such instances, the transaction (or part of the transaction) which relates to another year has been assigned to the relevant year, in accordance with the production month presentation described in section 2.2 of this application. Detail on the assignment between 2004 and other years for transactions which occurred from 2004 to 2009 is provided in Appendix E-1 of this application.

382 The AESO also notes that, as discussed in section 2.1.2 of this application, effective January 1, 2006, transmission system losses are no longer subject to retrospective deferral account reconciliation, and were therefore not included in sections 3, 4, 5, and 6 of this application relating to 2009, 2008, 2007, and 2006 respectively. However, transmission

system losses were subject to retrospective deferral account reconciliation in 2005 and prior years, and are therefore included in this section relating to 2004.

383

## 8.2 2004 Cost Adjustments After Second Reconciliation

384

The AESO's 2004 revenue requirement is provided as column (a) in Table 7-1, and was approved in:

- Alberta Energy and Utilities Board Decision 2004-012 on the AESO's 2004 General Tariff Application "Own Costs" Module, released on February 11, 2004;
- Alberta Energy and Utilities Board Order U2004-429 on the AESO's 2004 Phase I Revenue Requirement, released on December 2, 2004; and
- Alberta Energy and Utilities Board Decision 2005-005 on the AESO's 2004 General Tariff Application Phase I application for 2004 other costs, released on January 31, 2005.

385

Variances of recorded costs from that approved forecast were explained in the first and second reconciliations of the 2004 deferral account (for those transactions included in those first and second reconciliations). First reconciliation variances were approved in Commission Decision 2009-010 on the AESO's 2004-2007 Deferral Account Reconciliation released on January 27, 2009. Second reconciliation variances were approved in Commission Decision 2009-191 on the AESO's 2008 Deferral Account Reconciliation released on October 29, 2009. No further discussion of those variances is provided in this application. Only 2004 cost adjustments which arise from transactions that occurred after the second reconciliation are discussed in this application.

386

Specifically, the 2004 cost adjustments which occurred after the second deferral account reconciliation and which are included in this third reconciliation are those transactions that:

- relate to 2004,
- occurred after the cut-off date of December 31, 2008 for data included in the 2004 second reconciliation, and
- occurred up to December 31, 2009.

387

These 2004 cost adjustments, together with the original 2004-related transactions which were included in the first and second reconciliations, establish the 2004 production year cost data for deferral account reconciliation purposes in this application.

388

Table 8-1 includes the following information for 2004:

- column (b) contains the 2004 recorded costs included in the second reconciliation in the 2008 application;
- column (c) contains the 2004 recorded costs included in this application;
- column (d) provides the additional amounts attributed to 2004 which occurred after the cut-off date for transactions included in the second reconciliation — that is, the cost variances between the second and third reconciliations; and
- column (e) provides the 2004 additional amounts from column (d) as a percentage of the recorded costs from the second reconciliation in column (b).

*Table 8-1 2004 Second and Third Reconciliation Cost Variances, \$ 000 000*

Line No.	Approved Forecast	Recorded Costs		Variance Over (Under)	
		2008 2nd DAR <sup>1</sup>	2009 3rd DAR <sup>1</sup>	\$ (d)=(c)-(b)	% (e)=(d)÷(b)
	(a)	(b)	(c)	(d)=(c)-(b)	(e)=(d)÷(b)
<b>WIRES</b>					
<b>TFO Wires-Related Costs</b>					
1	AltaLink	160.3	157.5	157.5	0.1 0.0%
2	ATCO Electric Ltd.	170.0	152.4	152.4	- -
3	Isolated Generation	(5.1)	(4.8)	(4.8)	- -
4	Subtotal ATCO Costs	164.9	147.6	147.6	- -
5	ENMAX Power Corporation	33.4	33.2	33.2	- -
6	EPCOR Transmission Inc.	30.6	32.8	32.8	- -
7	City of Lethbridge	4.4	4.5	4.5	- -
8	TransAlta	2.3	3.4	3.4	(0.0) (1.2%)
9	Refund to the AESO	(9.9)	-	-	- -
10	Subtotal TransAlta Costs	(7.6)	3.4	3.4	(0.0) 0.5%
11	City of Red Deer	1.8	1.8	1.8	- -
12	FortisAlberta Networks (Farm)	1.9	1.9	1.9	- -
13	<b>Subtotal TFO Wires-Related Costs</b>	<b>389.7</b>	<b>382.7</b>	<b>382.7</b>	<b>0.0 0.0%</b>
<b>Non-Wires Costs</b>					
14	Invitation to Bid on Credits (IBOC)	3.2	2.1	2.1	- -
15	Location Based Credit Standing Offer (LBC SO)	6.4	5.7	5.7	- -
16	<b>Subtotal IBOC/LBC SO Costs</b>	<b>9.6</b>	<b>7.8</b>	<b>7.8</b>	<b>- -</b>
17	<b>TOTAL WIRES COSTS</b>	<b>399.3</b>	<b>390.5</b>	<b>390.5</b>	<b>0.0 0.0%</b>
<b>ANCILLARY SERVICES</b>					
<b>Operating Reserves</b>					
Active					
18	Regulating	36.4	25.1	25.1	- -
19	Spinning	38.8	25.7	25.7	- -
20	Supplemental	8.5	11.1	11.1	- -
21	<b>Subtotal Active Reserves</b>	<b>83.7</b>	<b>61.9</b>	<b>61.9</b>	<b>- -</b>
Standby					
22	Regulating	8.4	2.8	2.8	- -
23	Spinning	10.2	4.4	4.4	- -
24	Supplemental	2.7	1.3	1.3	- -
25	<b>Subtotal Standby Reserves</b>	<b>21.3</b>	<b>8.5</b>	<b>8.5</b>	<b>- -</b>
26	Trading Fees & Other Related Charges	-	(1.2)	(1.2)	- -
27	<b>Subtotal Operating Reserves</b>	<b>105.0</b>	<b>69.2</b>	<b>69.2</b>	<b>- -</b>
<b>Other Ancillary Services</b>					
28	Generator Remedial Action Schemes (RAS)	0.4	0.4	0.4	- -
29	Black Start	2.2	1.0	1.0	- -
30	Transmission Must-Run (TMR)	49.3	43.9	44.2	0.3 0.6%
31	Under Frequency Mitigation	6.5	6.9	6.9	- -
32	Hydro Motoring	-	-	-	- -
33	<b>Subtotal Other Ancillary Services</b>	<b>58.4</b>	<b>52.2</b>	<b>52.4</b>	<b>0.3 0.5%</b>

Table 8-1 2004 Second and Third Reconciliation Cost Variances, \$ 000 000 (continued)

Line No.	Approved Forecast (a)	Recorded Costs		Variance Over (Under)		
		2008 2nd DAR <sup>1</sup> (b)	2009 3rd DAR <sup>1</sup> (c)	\$ (d)=(c)-(b)	% (e)=(d)÷(b)	
<b>Poplar Hill/ILRAS</b>						
34	Poplar Hill	1.8	1.9	1.9	-	-
35	Interruptible Load Remedial Action Scheme (ILRAS)	1.1	0.5	0.5	-	-
36	<b>Subtotal Poplar Hill/ILRAS</b>	<b>2.9</b>	<b>2.4</b>	<b>2.4</b>	<b>-</b>	<b>-</b>
37	<b>TOTAL ANCILLARY SERVICES</b>	<b>166.3</b>	<b>123.7</b>	<b>124.0</b>	<b>0.3</b>	<b>0.2%</b>
<b>LOSSES</b>						
38	Pool Payment	159.9	145.6	145.6	-	-
39	Losses Studies Surcharge	-	-	-	-	-
40	<b>TOTAL LOSSES COSTS</b>	<b>159.9</b>	<b>145.6</b>	<b>145.6</b>	<b>-</b>	<b>-</b>
<b>OTHER INDUSTRY COSTS</b>						
41	External Regulatory Costs	4.4	2.3	2.3	-	-
42	Western Electricity Coordinating Council (WECC)	0.9	0.8	0.8	-	-
43	Share of EUB Overhead	2.0	1.8	1.8	-	-
44	Balancing Pool	-	-	-	-	-
45	<b>TOTAL OTHER INDUSTRY COSTS</b>	<b>7.3</b>	<b>5.0</b>	<b>5.0</b>	<b>-</b>	<b>-</b>
<b>GENERAL AND ADMINISTRATIVE COSTS</b>						
<b>Administrative Costs</b>						
46	Staff and Benefits	16.0	16.8	16.8	-	-
47	Interconnection Fees (Offset)	(0.9)	(0.7)	(0.7)	-	-
48	<b>Subtotal Staff &amp; Benefits</b>	<b>15.1</b>	<b>16.1</b>	<b>16.1</b>	<b>-</b>	<b>-</b>
49	Consultants	2.9	3.9	3.9	-	-
50	Interconnection Fees (Offset)	-	(0.4)	(0.4)	-	-
51	<b>Subtotal Consultants</b>	<b>2.9</b>	<b>3.5</b>	<b>3.5</b>	<b>-</b>	<b>-</b>
52	Board Members Fees	0.3	0.3	0.3	-	-
53	Travel and Training	1.0	1.0	1.0	-	-
54	Legal	0.4	0.4	0.4	-	-
55	Accounting and Tax Advice	0.3	0.0	0.0	-	-
56	Rent <sup>2</sup>	1.0	0.9	0.9	-	-
57	Insurance	0.3	0.3	0.3	-	-
58	Other Administrative Costs	1.4	2.2	2.2	-	-
59	Negotiated Settlement Reduction	-	-	-	-	-
60	<b>Total Administrative Costs</b>	<b>22.8</b>	<b>24.9</b>	<b>24.9</b>	<b>-</b>	<b>-</b>

Table 8-1 2004 Second and Third Reconciliation Cost Variances, \$ 000 000 (continued)

Line No.	Approved Forecast (a)	Recorded Costs		Variance Over (Under)		
		2008 2nd DAR <sup>1</sup> (b)	2009 3rd DAR <sup>1</sup> (c)	\$ (d)=(c)-(b)	% (e)=(d)÷(b)	
<b>General Costs</b>						
61	Interest	0.1	0.2	0.2	-	-
62	Amortization and Depreciation	1.8	1.6	1.6	-	-
63	Tariff Deficiency Correction Regulation Fee	-	-	-	-	-
64	ISO Transition Costs	-	-	-	-	-
65	Taxes	-	(0.4)	(0.4)	-	-
66	<b>Total General Costs</b>	<b>1.9</b>	<b>1.4</b>	<b>1.4</b>	<b>-</b>	<b>-</b>
67	<b>TOTAL GENERAL &amp; ADMIN COSTS</b>	<b>24.7</b>	<b>26.3</b>	<b>26.3</b>	<b>-</b>	<b>-</b>
68	<b>Total G&amp;A and Other Industry Costs</b>	<b>32.0</b>	<b>31.2</b>	<b>31.2</b>	<b>-</b>	<b>-</b>
69	<b>TOTAL REVENUE REQUIREMENT</b>	<b>757.5</b>	<b>691.0</b>	<b>691.3</b>	<b>0.3</b>	<b>0.0%</b>
70	<b>CAPITAL</b>	<b>3.3</b>	<b>5.2</b>	<b>5.2</b>	<b>-</b>	<b>-</b>

Notes: Numbers may not add due to rounding.

Shaded numbers indicate significant variances which are discussed in the text.

<sup>1</sup> DAR means Deferral Account Reconciliation.

<sup>2</sup> Amortization of Rent Free Period not included in 2004 Recorded Costs on Line 56.

389 As already discussed in the previous sections of this application, variances arise due to a number of factors, including finalization of TFO costs through Commission decisions, variances from forecast of volumes and pool price, delays and changes in AESO schedules and priorities, and generally expected adjustments that occur over time. In the second reconciliation for 2004, in the 2008 deferral account reconciliation application, the AESO considered a line item variance to be significant when it exceeded  $\pm\$1.5$  million, or, if it was smaller than  $\pm\$1.5$  million, when it was both at least  $\pm\$0.15$  million and at least  $\pm 5\%$  of the approved line item amount.

390 In this third reconciliation for 2004, variances are represented by cost adjustments which occurred after the second reconciliation. It seems inappropriate to use the same threshold levels for variance explanations for adjustments as would be used in a second reconciliation. The AESO considers it reasonable to reduce the variance explanation thresholds by one-third, recognizing that costs may have varied from forecast in the first and second reconciliations and may also vary again due to further adjustments in this third reconciliation. Although each variance might be less than the first or second reconciliation threshold, together they may exceed it.

391 Therefore, in Table 8-1, the AESO considered a line item variance to be significant when it exceeded  $\pm\$1.0$  million, or, if it was smaller than  $\pm\$1.0$  million, when it was both at least  $\pm\$0.1$  million and at least  $\pm 3\%$  of the first reconciliation recorded costs line item amount. Variances exceeding these thresholds are shaded in Table 8-1, with explanations provided

by line number in the following discussion. Where variances were either less than  $\pm\$0.1$  million or less than  $\pm 3\%$  (except where such variance is  $\pm\$1.0$  million or greater) explanations are not provided, as such variances are considered small enough that specific variance explanations are not required.

392 For the 2004 third reconciliation recorded costs in this application, no variance exceeded the threshold discussed above. However, the AESO provides the following explanation for the largest cost variance for the 2004 third reconciliation.

### 8.2.1 Ancillary Services

393 The 2004 third reconciliation recorded costs for ancillary services were \$124.0 million, which is \$0.3 million (or 0.2%) more than the second reconciliation recorded costs of \$123.7 million, due to payments for transmission must-run service as discussed in more detail below.

#### Lines 30 Transmission Must-Run (“TMR”) Service

394 TMR is generation required to be on-line and operating at specific levels in particular parts of the AIES in order to ensure system security. The majority of TMR service is foreseeable, which the AESO generally procures through a competitive procedure resulting in commercial agreements between the AESO and TMR suppliers. When the TMR service is unforeseeable, the AESO may conscript and pay suppliers under the methodology detailed in Article 11 of the AESO’s tariff.

395 The 2004 third reconciliation recorded TMR cost was \$44.2 million, which is \$0.3 million (or 0.6%) more than the second reconciliation recorded cost of \$43.9 million. The increase was due to finalization of a review of costs for unforeseeable TMR service under the compensation methodology to be retrospectively applied to the period December 17, 2004 until February 12, 2008, according to the terms of the AESO’s Ancillary Services Article 11 Negotiated Settlement approved in Commission Decision 2008-014 released on February 12, 2008. The AESO believes that as of December 31, 2009, no costs for unforeseeable TMR service remain outstanding with respect to 2004.

### 8.3 2004 Revenue Adjustments After Second Reconciliation

396 The AESO’s 2004 forecast “base rate” revenue was discussed in the 2004-2007 deferral account reconciliation application. Base rates exclude Deferral Account Adjustment Rider C, which collects or refunds revenue during the year to align actual revenue with actual costs by rate and rate component. The AESO does not forecast Rider C amounts as part of its tariff applications, and Rider C is therefore not included in this discussion of variances from forecast. Base rate revenue also excludes any amounts collected or refunded through deferral account reconciliation applications.

397 Variances of recorded base rate revenue from the 2004 first reconciliation were explained in the second reconciliation of the 2004 deferral account (for those transactions included in that second reconciliation). Those variances were approved in Commission Decision 2009-191 on the AESO’s 2008 deferral account reconciliation released on October 29, 2009. No further discussion of those base rate revenue variances is provided in this

application. Only revenue adjustments which arise from transactions that occurred after the second reconciliation are discussed in this application.

398 Specifically, the 2004 revenue adjustments which occurred after the second deferral account reconciliation and which are included in this third reconciliation are those transactions that:

- relate to 2004,
- occurred after the cut-off date of December 31, 2008 for data included in the 2004 second reconciliation, and
- occurred up to December 31, 2009.

399 These 2004 revenue adjustments, together with the 2004-related transactions which were included in the first and second reconciliations, establish the 2004 production year revenue data for deferral account reconciliation purposes in this application.

400 Table 8-2 accordingly includes the following information for 2004:

- column (b) contains the 2004 recorded base rate revenue included in the second reconciliation in the 2008 application;
- column (c) contains the 2004 recorded base rate revenue included in this application;
- column (d) provides the additional base rate revenue amounts attributed to 2004 which occurred after the cut-off date for transactions included in the second reconciliation — that is, the revenue variances between the second and third reconciliations; and
- column (e) provides the 2004 additional revenue amounts from column (d) as a percentage of the recorded revenue from the second reconciliation in column (b).

401 The 2004 third reconciliation recorded base rate revenue was \$757.9 million, which is the same as the second reconciliation recorded revenue.

402 On an annual basis, transmission revenue depends on approved transmission tariff rates, pool price, and billed volumes of demand and energy. Revenue variances after the first reconciliation generally arise due to billing adjustments, primarily reflecting changes to metered volumes such as those that occur in post-final adjustments. There were no variances between the second and third reconciliation recorded revenues for 2004.

#### **8.4 2004 Third Reconciliation Deferral Account Balance**

403 Costs and revenue variances attributed to a year give rise to deferral account balances. The deferral account balances for the 2004 third reconciliation are summarized in Table 8-3, and reflect the 2004 third reconciliation costs and revenues provided in Table 8-1 and 8-2 respectively.

404 As noted in section 1.1 of this application, the AESO's tariff includes the use of deferral accounts, which were incorporated in the AESO's 2004 tariff through Working Capital Deficiency/Surplus Rider B and Deferral Account Adjustment Rider C. The AESO did not invoke Rider B during 2004, but determined Rider C charges and refunds in accordance with the rider's approved purpose to "restore deferral account balances to zero over the

Table 8-2 2004 Second and Third Reconciliation Revenue Variances, \$ 000 000

Line No.	Forecast Revenue	Recorded Revenue		Variance Over (Under)		
		2008 2nd DAR <sup>1</sup>	2009 3rd DAR <sup>1</sup>	\$	%	
	(a)	(b)	(c)	(d)=(c)-(b)	(e)=(d)÷(b)	
<b>Demand Transmission Service</b>						
1	Interconnection	\$226.6	\$227.6	\$227.6	-	-
2	Operating Reserve	116.7	119.9	119.9	-	-
3	Other System Support	2.3	2.2	2.2	-	-
4	<b>Total DTS</b>	<b>\$345.6</b>	<b>\$349.6</b>	<b>\$349.6</b>	<b>-</b>	<b>-</b>
<b>Supply Transmission Service</b>						
5	Interconnection	\$155.8	\$153.5	\$153.5	-	-
6	Losses	177.1	138.4	138.4	-	-
7	Operating Reserve	118.0	116.4	116.4	-	-
8	<b>Total STS</b>	<b>\$450.9</b>	<b>\$408.3</b>	<b>\$408.3</b>	<b>-</b>	<b>-</b>
<b>Total DTS and STS</b>						
9	Interconnection	\$382.4	\$381.0	\$381.0	-	-
10	Losses	177.1	138.4	138.4	-	-
11	Operating Reserve	234.8	236.3	236.3	-	-
12	Other System Support	2.3	2.2	2.2	-	-
13	<b>Total DTS and STS</b>	<b>\$796.5</b>	<b>\$757.9</b>	<b>\$757.9</b>	<b>-</b>	<b>-</b>

Notes: Numbers may not add due to rounding.

<sup>1</sup> DAR means Deferral Account Reconciliation.

following calendar quarter". The AESO sets Rider C rates each quarter based on estimates of deferral account balances at the end of that quarter and forecast billing volumes for that quarter. Rider C charges and refunds attributed to 2004 are provided in column (d) of Table 8-3.

405 As noted in section 1.1 of this application, the AESO's tariff includes the use of deferral accounts, which were incorporated in the AESO's 2004 tariff through Working Capital Deficiency/Surplus Rider B and Deferral Account Adjustment Rider C. The AESO did not invoke Rider B during 2004, but determined Rider C charges and refunds in accordance with the rider's approved purpose to "restore deferral account balances to zero over the following calendar quarter". The AESO sets Rider C rates each quarter based on estimates of deferral account balances at the end of that quarter and forecast billing volumes for that quarter. Rider C charges and refunds attributed to 2004 are provided in column (d) of Table 8-3.

406 The second reconciliation of the 2004 deferral account in the AESO's 2008 deferral account reconciliation application resulted in a \$0.1 million surplus attributed to 2004, as illustrated in

*Table 8-3 2004 Third Reconciliation Deferral Account Summary, \$ 000 000*

Line No.	Recorded	Recorded	Over	Prior Deferral Account		Net Over (Under)	
	Base Rate Revenue		(Under) Collection	Collections (Refunds)	Collection Variance	\$	%
	(a)	(b)	(c)=(a)+(b)	Rider C (d)	DARs <sup>1</sup> (e)	(f)=Σ(c):(e)	(g)=- (f)÷(b)
<b>Demand Transmission Service</b>							
1	Interconnection	\$227.6	(\$244.8)	(\$17.3)	\$22.6	(\$5.3)	(\$0.0) (0.0%)
2	Operating Reserve	119.9	(60.8)	59.1	(60.1)	0.9	(0.1) (0.2%)
3	Other System Support	2.2	(2.2)	(0.0)	0.2	(0.1)	(0.0) (0.0%)
4	<b>Total DTS</b>	<b>\$349.6</b>	<b>(\$307.8)</b>	<b>\$41.8</b>	<b>(\$37.4)</b>	<b>(\$4.6)</b>	<b>(\$0.1) (0.0%)</b>
<b>Supply Transmission Service</b>							
5	Interconnection	\$153.5	(\$177.1)	(\$23.6)	\$28.3	(\$4.6)	(\$0.0) (0.0%)
6	Losses	138.4	(145.6)	(7.2)	(7.7)	14.8	(0.0) (0.0%)
7	Operating Reserve	116.4	(60.8)	55.6	(55.3)	(0.4)	(0.1) (0.2%)
8	<b>Total STS</b>	<b>\$408.3</b>	<b>(\$383.5)</b>	<b>\$24.8</b>	<b>(\$34.7)</b>	<b>\$9.8</b>	<b>(\$0.1) (0.0%)</b>
<b>Total DTS and STS</b>							
9	Interconnection	\$381.0	(\$421.9)	(\$40.9)	\$50.8	(\$9.9)	(\$0.0) (0.0%)
10	Losses	138.4	(145.6)	(7.2)	(7.7)	14.8	(0.0) (0.0%)
11	Operating Reserve	236.3	(121.6)	114.6	(115.4)	0.5	(0.3) (0.2%)
12	Other System Support	2.2	(2.2)	(0.0)	0.2	(0.1)	(0.0) (0.0%)
13	<b>Total DTS and STS</b>	<b>\$757.9</b>	<b>(\$691.3)</b>	<b>\$66.6</b>	<b>(\$72.1)</b>	<b>\$5.2</b>	<b>(\$0.3) (0.0%)</b>

Notes: Numbers may not add due to rounding.

<sup>1</sup> DAR means Deferral Account Reconciliation.

Table 2-3 in section 2.3 of this application. The second reconciliation surplus was refunded to customers in the interim settlement in late June 2009 of the AESO's 2008 deferral account balances, which was approved on a final basis in Commission Decision 2009-191. Second reconciliation settlement amounts attributed to 2004 are included with first reconciliation settlement amounts in column (e) of Table 8-3, and restored all 2004 deferral account balances to zero based on the transactions included in the 2004 second reconciliation.

407 However, this third reconciliation includes adjustments to costs and revenues that occurred after the second reconciliation of the 2004 deferral account, as discussed in sections 8.2 and 8.3 where explanations were provided when the resulting line item variances were significant.

408 There were no significant changes to 2004 deferral account balances for individual rate component charges compared to the second reconciliation.



- 409 The impact of all 2004 cost and revenue adjustments is a deferral account net balance increase to an undercollection of \$0.3 million (or 0.04% of recorded costs), compared to the zero balance that existed after settlement of amounts included in the second reconciliation.
- 410 Additional details on 2004 recorded costs and revenues are provided in Appendices B through G of this application. The allocation of the 2004 net deferral account balances to customers is discussed in section 9 of this application.

## 9 ALLOCATION TO CUSTOMERS

411 Deferral account balances and adjustments are allocated to customers as in the AESO's recent deferral account reconciliation applications. The allocation is implemented through the continued use of a software program developed by the AESO to automate deferral account reconciliation calculations.

### 9.1 Allocation of 2004 to 2009 Deferral Account Balances

412 As in the previous deferral account reconciliation applications for 2003, 2004-2007, and 2008, deferral account balances are calculated on a production month basis as the costs paid by rate and rate component for each year from 2004 to 2009. Consistent with treatment in prior years, these deferral account balances have been allocated to individual customers based on each customer's percentage of total revenue collected based on the rates in place during the period, by month and by rate component, except for losses.

413 As discussed in section 2.1.2 of this application, effective January 1, 2006, transmission system losses are no longer subject to retrospective deferral account reconciliation. Since that time, Calibration Factor Rider E has adjusted loss factors for the recovery of the actual costs of losses on a prospective basis in accordance with section 33(1) of the *Transmission Regulation*. There is accordingly no allocation of losses deferral account balances to customers included in this application for 2006, 2007, 2008, and 2009.

414 Deferral account balances associated with losses for 2004 and 2005 remain subject to retrospective deferral account reconciliation and are included in this application. As in the prior deferral account reconciliation applications, those 2004 and 2005 balances for losses deferral accounts have been allocated to individual customers based on each customer's hourly production multiplied by the pool price in the hour, summed over each production month. The losses allocation methodology is consistent with the manner in which the costs of losses are recovered. During 2004 and 2005, generators paid losses charges on the basis of normalized loss factors, which are the aggregate of "raw" loss factors that are unique to each generator and "shift" factors that apply equally to all generators. Thus, for example, two generators with identical generation profiles paying different losses charges would have been equally affected by higher than necessary shift factors and should receive equal refunds. Applying credits or charges on the basis of total revenues received related to losses would produce, in this instance, the incorrect result of refunding different amounts to each of these similar generators. The "production times pool price" allocation methodology, as approved in prior reconciliation applications and as utilized in this application, correctly refunds the same amount to each of these similar generators.

415 After the allocation of deferral account balances is determined by rate and rate component for each customer, additional revenue already paid by or refunded to each customer (through Rider C or in prior deferral account reconciliation settlements) is subtracted or added by rate and rate component. The remaining balance is the amount of the deferral account charge or refund attributed to the customer on a production month basis, by rate and rate component.

416 For additional clarity, in this application the second reconciliation for 2008 and the third reconciliations for 2004 through 2007 all include deferral account charges or refunds relating to those years which were financially settled in 2005, 2008, and 2009 as a result of prior reconciliation proceedings. The additional revenue by customer that is subtracted from or added to the deferral account balances includes the settlement amounts approved in the 2003, 2004-2007, and 2008 deferral account reconciliation proceedings.

## 9.2 Provision of Customer Allocation Information

417 The results of the deferral account allocation for each DTS and STS customer are included in Appendices G, I, J, and K of this application, in annual customer detail summaries and customer allocation detail. As discussed in section 2.7 of this application, customer confidentiality is protected by assigning a number to each AESO direct-connect customer as has been done in prior deferral account reconciliation applications. The numbers assigned to a specific customer are not necessarily the same for each deferral account year in this application, and are not necessarily the same as those used in prior applications.

418 After filing this application, the AESO will distribute to each customer the applicable customer and generator numbers for the deferral account reconciliation years included. As well, the AESO will provide to any customer on request deferral account allocation data for each of the customer's settlement points. Such information is too extensive and detailed to be included with this application, and it is impractical to protect customer confidentiality through numerical coding when dealing with hundreds of settlement points. Instead, the AESO will advise customers of the availability of settlement point data at the time it provides customer and generator numbers. The settlement point data will include information comparable to that provided in Appendices G, I, J, and K, in Microsoft Excel format.

419 The AESO notes that a customer may assign its System Access Service Agreement to another customer (the "assignee") in accordance with the AESO's tariff (for example, under Article 21.2 of the AESO's currently-approved 2007 terms and conditions of service). Where such an assignment has occurred, the deferral account allocation will be applied to the account of the assignee, and the applicable customer numbers will be provided only to the assignee.

420 The most recent assignment of a System Access Service Agreement occurred in December 2009, with no further assignments occurring in the remainder of 2009 or in the first quarter of 2010. The AESO has therefore determined assignees as of March 31, 2010 for charges and refunds included in this application.

## 9.3 Application of GST to Deferral Account Balances

421 The Goods and Services Tax ("GST") rate that is being applied to the deferral account balances being charged and refunded in this application is the current legislated federal GST rate of 5%. While the amounts settled through this application relate to transactions that originated back to 2004, it is the GST rate that is in effect when the GST becomes payable or is paid that is applied. With respect to this application, the GST will become

payable or be paid when the Commission approves the interim settlement of customer charges and refunds as discussed in section 1.2 of this application.

- 422 The GST rate was reduced by the federal government from 7% to 6% in July 2006, and then to 5% in January 2008. The Canada Revenue Agency (“CRA”) has indicated that when a transaction was originally subject to the 7% or 6% rate and is subsequently adjusted, the adjustment should be at the same GST rate as the original transaction. However, it is recognized that because of limitations in systems and processes, it may be necessary to apply the current rate to an adjustment even though the original transaction was subject to the previous rates. In the case of reductions between registered businesses, this is unlikely to be a concern as GST collected and paid is netted for tax reporting purposes.
- 423 Consistent with the application of GST to all settlement billings prepared by the AESO, all transactions, including both upward and downward adjustments, have the current GST rate applied.

## 10 PROPOSED METHOD OF REFUNDING AND COLLECTING

424 Consistent with the approach approved for the AESO's prior deferral account reconciliations, the AESO proposes to settle the outstanding deferral account balances through a one-time payment and collection option.

425 The overall cash flow impact is manageable, recognizing that the individual refunds to, and collections from, each customer must be administered within a 30 to 60 day timeframe in order to ensure cash flow stability for the AESO. Under this option, the AESO proposes to refund or collect the amounts for each customer within 60 days from the date of the Commission decision regarding this application.

426 Although the AESO favours the one-time payment and collection option to expedite the final resolution and financial settlement related to the deferral account balances, it appreciates that it is not in a position to determine if this option presents a financial burden to its customers. If this option does present a financial burden to a customer, the AESO considers it reasonable to offer a 3-month payment option, including carrying charges, similar to that offered to customers in previous deferral account reconciliations.

### 10.1 Immediate Interim Settlement

427 As discussed in section 1.2 of this application, the AESO proposes that the refunds and charges to and from customers as a result of this application be settled as soon as possible on an interim refundable basis. The AESO understands that prior to approving immediate interim settlement, the Commission would need to be satisfied that the amounts are accurate and that such an order is in the public interest.

428 The AESO considers that the reasons set out in section 1.2 provide a sufficient basis to allow the Commission to conclude that interim settlement of the deferral account balances in the amounts allocated in this application would be both accurate and in the public interest. The AESO will therefore plan interim settlement on invoices to be issued in June 2010, pending approval of the Commission.

429 Appendix G includes the total Rate DTS and Rate STS amounts that will be settled with individual customers on an interim refundable basis as a result of this application, pending approval of the Commission. Table 10-1 summarizes the distribution of charges and refunds among individual Rate DTS and individual Rate STS customers.

430 Table 10-1 indicates that 6 Rate DTS and 2 Rate STS customers will receive refunds totalling \$6.6 million while 41 Rate DTS and 37 Rate STS customers will receive charges totalling \$4.8 million, as a result of this 2009 application.

431 The total refunds are \$4.8 million more than the \$1.8 million net deferral account surplus being settled. This \$4.8 million amount indicates the magnitude of the reallocation of Rider C charges and refunds among customers in this reconciliation. The AESO submits that settlement of the amounts in this application would therefore improve the accuracy of the

**Section 10 — Proposed Method of Refunding and Collecting**  
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*Table 10-1 Distribution of Charges and Refunds Among Customers*

Range of Refunds and Charges	Number of Customers			Total Amount, \$ 000 000			
	DTS		STS	DTS			Total
	DFO <sup>1</sup>	Non-DFO		DFO <sup>1</sup>	Non-DFO	STS	
Refund Greater Than \$2,000,000	1	-	-	\$2.6	-	-	\$2.6
Refund Greater Than \$1,000,000 to \$2,000,000	2	-	-	3.6	-	-	3.6
Refund Greater Than \$500,000 to \$1,000,000	-	-	-	-	-	-	-
Refund Greater Than \$100,000 to \$500,000	1	1	-	0.2	0.3	-	0.4
Refund Greater Than \$50,000 to \$100,000	-	-	-	-	-	-	-
Refund of \$0 to \$50,000	-	1	2	-	0.0	0.0	0.0
<b>Subtotal Refunds</b>	<b>4</b>	<b>2</b>	<b>2</b>	<b>\$6.3</b>	<b>\$0.3</b>	<b>\$0.0</b>	<b>\$6.6</b>
Charge Greater Than \$0 to \$50,000	-	20	37	-	(0.2)	(0.2)	(0.5)
Charge Greater Than \$50,000 to \$100,000	-	4	-	-	(0.2)	-	(0.2)
Charge Greater Than \$100,000	2	15	-	(0.4)	(3.8)	-	(4.1)
<b>Subtotal Charges</b>	<b>2</b>	<b>39</b>	<b>37</b>	<b>(\$0.4)</b>	<b>(\$4.2)</b>	<b>(\$0.2)</b>	<b>(\$4.8)</b>
<b>Total Refunds and Charges</b>	<b>6</b>	<b>41</b>	<b>39</b>	<b>\$6.0</b>	<b>(\$4.0)</b>	<b>(\$0.2)</b>	<b>\$1.8</b>

Notes: Numbers may not add due to rounding.

<sup>1</sup> DFO means Distribution Facility Owner.

allocation of deferral account balances to customers, which further supports the approval of interim settlement of the deferral account amounts in this application.

- 432 As already noted, the amounts settled on invoices issued in June 2010 would be interim and refundable, and subject to adjustment in the final decision on the 2009 deferral account reconciliation application following a full regulatory review. In the event such adjustment is required, the AESO proposes that the impact of the adjustment be assessed to determine whether a separate settlement process is required or whether the adjustment can be included in the 2010 deferral account reconciliation application expected to be filed in the second quarter of 2011.
- 433 The AESO suggests it may be efficient to continue to settle future deferral account reconciliations on an immediate interim basis upon filing, with any required minor adjustments included in the following year's deferral account reconciliation. Additional comments on future deferral account reconciliations are provided in section 2.8 of this application.

## 11 RESPONSES TO DIRECTIONS

434 Commission decisions on the AESO's 2008 deferral account reconciliation and other applications included directions and instructions to the AESO which were to be addressed in an application to the Commission. In this section, the AESO summarizes the responses included in this deferral account reconciliation application to directions and instructions from the following decisions:

- Commission Decision 2009-151 on AltaLink Management Ltd.'s and TransAlta Corporation's 2009 and 2010 transmission facility owner tariffs, released on October 2, 2009; and
- Commission Decision 2009-191 on the AESO's 2008 deferral account reconciliation, released on October 29, 2009.

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**1 Address \$35 Million Backstop Arrangement Payment to AltaLink** Page 1 of 1

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**Direction From Decision 2009-151**

435 Accordingly, the Commission directs AltaLink to give effect to the \$35 million backstop arrangement as soon as possible and to provide a full description of the details of the completion of this transaction at the time of AltaLink's Refiling. The Commission expects that AESO will address alternatives for funding the execution of this backstop arrangement either within an upcoming GTA or through a separate application to the Commission. [section 8.3, page 92, paragraph 529]

**Response**

436 This application includes the recovery of \$35 million of costs incurred for the cancelled Genesee-Langdon 500 kV project, which were paid to AltaLink by the AESO on December 31, 2009 in accordance with the Commission's direction to AltaLink in Decision 2009-151.

437 The AESO had filed an application on December 2, 2009 to review and vary the Commission's finding with respect to this direction. The Commission dismissed the AESO's request in Decision 2010-147, released on April 6, 2010, on the preliminary question of whether the original decision should be reviewed. Based on the Commission's confirmation of its original determination in Decision 2009-151, the AESO has included the \$35 million payment to AltaLink in the 2009 deferral account reconciliation as discussed in more detail in section 3.1.1 of this application.

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**2 Include Balance of KEG Costs in Next Deferral Account Reconciliation**

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**Direction From Decision 2009-191**

438 In view of AESO's explanation that final costs arising from the KEG transformer conversion project were not available by December 31, 2008, the Commission accepts AESO's proposal to reflect any cost balance paid by AESO after December 31, 2008 in AESO's 2009 deferral account reconciliation. In accordance with this finding, the Commission directs AESO to include any costs not already accounted for in the current application in its next deferral account reconciliation application. [section 5, page 8, paragraph 43]

**Response**

439 The AESO received and paid one invoice in addition to those accounted for in the 2008 deferral account reconciliation application. All costs for the KEG unit transformers conversion project have now been finalized.

440 The additional cost of \$2.2 million paid in 2009 has been attributed to 2008 and included in this deferral account reconciliation, as discussed in more detail in section 4.2.1 of this application.

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**3 Consider Commission Concern About Repeated Reconciliations of Deferral Account Years** Page 1 of 1

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**Direction From Decision 2009-191**

441 Notwithstanding this finding, the Commission wishes to highlight its concern about the number of times that additional reconciliation is required in respect of deferral account years that have already been considered by the Commission in the context of prior deferral account reconciliation applications. The Commission urges AESO to be mindful of this concern as it considers its redesign of deferral account reconciliation processes and associated rate riders for its forthcoming GTA. [section 7, page 11, paragraph 57]

**Response**

442 The AESO included a discussion of future deferral account reconciliation applications in section 8.3 (pages 262-264) of its 2010 ISO tariff application, submitted to the Commission on March 5, 2010. That discussion noted that “the AESO is not proposing any redesign of its deferral account reconciliation processes in this [2010 ISO tariff] application.” The AESO also noted that “there may be opportunities for changes to the approval process rather than the reconciliation processes to address the concern expressed” by the Commission, and considered that “such proposals should be more properly addressed in a deferral account reconciliation application than in a tariff application.”

443 The AESO has accordingly included a discussion of future deferral account reconciliations in section 2.8 (pages 25-29) of this application. In that section, the AESO summarized the changes it investigated to simplify and improve the efficiency of the deferral account reconciliation process. The AESO also discussed a modification to the review and approval process while continuing multi-year retrospective deferral account reconciliations, whereby a compliance review of calculations and allocation methodology would remove the need for the Commission’s specific approval of deferral account re-reconciliations. In this application the AESO requests approval to implement such a compliance review approach in future deferral account reconciliation applications.

444 The AESO submits that the information provided in section 2.8 of this application responds to the Commission’s concern as stated in the direction in Decision 2009-191.