

**IN THE MATTER OF** the Alberta Electric System Operator tariff and rates approved by the Alberta ~~Energy and~~ Utilities ~~Board~~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 ~~EUB~~Alberta Utilities Commission Approval of the AESO's deferral account balance reconciliations for the ~~periods January 1 to December 31~~calendar years 2007, 2006, 2005, ~~January 1 to December 31~~, 2004, and ~~January 1 to December 31~~, 2003, and for adjustments to the AESO's deferral account balance reconciliations for the period January 1, 1999 to December 31, 2002.

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**Alberta Electric System Operator  
2004-~~2005~~2007 Deferral Account Reconciliation  
Application**

**December 1, 2007  
June 2, 2008**

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**Alberta Electric System Operator  
AESO 2004-2007 Deferral Account Reconciliation Application  
June 2, 2008**

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## 1 APPLICATION

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

10 The application seeks approval of the AESO’s first reconciliation of deferral accounts for ~~2007, 2006, 2005,~~ and 2004 and of the AESO’s second reconciliation of deferral accounts for 2003. 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.

15 The application also seeks approval of adjustments to the previously reconciled variances for the years 1999 to 2002, and ~~effor~~ the allocation, refund, and collection of those adjustments.

### 20 1.1 Background

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

25 The AESO’s tariffs which were in place in 2003, 2004, ~~2005, 2006,~~ and ~~2005~~2007 were approved in various decisions and orders of the AUC (where, for simplicity in this application, references to the AUC include the Alberta Energy and Utilities Board as its predecessor) as follows:

- 30
- ~~EUB~~-Decision 2002-087 dated October 8, 2002 (tariff effective November 1, 2002);
  - ~~EUB~~-Decision 2003-077 dated November 4, 2003 (tariff effective December 1, 2003);
  - ~~EUB~~-Decision 2003-099 dated December 16, 2003 (amendments effective January 1, 2004); ~~and~~
  - ~~EUB~~-Order U2004-476 dated December 24, 2004 (tariff effective January 1, 2005); and
  - Order U2005-464 dated December 20, 2005 (tariff effective January 1, 2006).
- 35

40 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 profit or loss results from the AESO’s operation in accordance with section 14 of the EUA. 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 EUA.

45

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

- 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.”

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 EUBAUC. Under the deferral account methodology most recently approved by the EUBAUC, 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 the 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.

The reconciliation of deferral account balances and the associated allocation of those balances to customers have previously been addressed by the EUBAUC in Decision 2003-099 for 2000, 2001, and 2002 and in Decision 2005-034 for 2003.

Decision 2003-099 included directions to the AESO to evaluate Rider C in a trial period in 2004, and to provide the results of the trial and a recommended rider methodology to be used for 2004. The AESO responded to those directions in a compliance filing on October 21, 2004, and which concluded that the retrospective year-end reconciliation process as conducted in prior years be continued for 2004. The AESO also noted in the compliance filing that it proposed to discuss the implementation of a prospective deferral account rider methodology in a stakeholder consultation process. The EUBAUC notified parties that it considered that the compliance filing substantially complied with the Decision 2003-099 directions, in a letter dated November 10, 2004.

The AESO consulted with stakeholders in November 2004, and after further review concluded that the retrospective year-end reconciliation process should also be continued for 2005. The AESO subsequently filed a 2004-2005 deferral account methodology application on December 16, 2004, requesting approval of a retrospective reconciliation methodology for the AESO’s deferral account for 2004 and 2005. No specific change was required to the AESO’s tariff as a result of this application, and the application was eventually closed without further action by the EUBAUC on January 12, 2006.

During the proceeding for the 2003 Deferral Account Reconciliation, the AESO committed to stakeholder consultation on the data cut-off date to be used for future deferral account reconciliations and the treatment of carryover adjustments which occur after the cut-off date. The AESO conducted this consultation during 2005, resulting in several enhancements to the deferral account reconciliation process which have been implemented in this 2004-~~2005~~

2007 application. The results of the stakeholder consultation are discussed in more detail in Appendix A of this application.

5 In accordance with the conclusions of its stakeholder consultation, the AESO ~~provides in this prepared an~~ application comprising the first ~~reconciliation reconciliations~~ of 2005 and 2004 deferral account balances, a second reconciliation of 2003 deferral account balances, and reconciliation of deferral account adjustments relating to the years 1999 to 2002. The AESO's 2004-2005 Deferral Account Reconciliation Application was submitted to the AUC on December 1, 2007 as Application Number 1548908.

10 Subsequent to the filing of the 2004-2005 Application, the AESO's deferral account balances increased materially, due in large part to additional prior period amounts refunded to the AESO at the end of 2007 and in early 2008. The AESO examined alternatives that would allow a prompt return of these additional amounts to customers and conducted a brief stakeholder consultation process on the matter. As a result, the AESO proposed, and the AUC approved by letter dated April 16, 2008, that the 2004-2005 Application be held in abeyance pending the filing of a revised and extended 2004-2007 Deferral Account Reconciliation Application.

20 In accordance with the process described in the AUC's letter, the AESO provides in this application the first reconciliations of 2007, 2006, 2005, and 2004 deferral account balances as well as a second reconciliation of 2003 deferral account balances. The 2007, 2006, 2005, 2004, and 2003 deferral account reconciliations have been prepared on a retrospective, monthly, and production month basis, consistent with the method used in the 2003 first reconciliation (as ~~refilled~~refiled on December 14, 2004) as reviewed and approved by the EUBAUC. More detailed discussion of the deferral account balances are provided in sections 3 (for ~~2005~~2007), 4 (for ~~2004~~and 2006), 5 (for 2005), 6 (for 2004), and 7 (for 2003) of this application.

30 This application also includes deferral account adjustments relating to the years from 1999 to 2002, prior periods during which deferral accounts were approved for the AESO. Adjustments for these prior years are addressed through a simplified approach described in section 6-8 of this application.

35 The 2007, 2006, 2005, 2004, and 2003 deferral account reconciliations included in this application take into account EUBAUC directions contained in Decisions 2003-099 and 2005--034. Responses to directions which were specific to the AESO's 2004 deferral account reconciliation process are included in section 9-11 of this application. Section 11 also includes response to the direction contained in the AUC's April 16, 2008 letter approving the suspension of the original 2004-2005 application and the filing of this extended 2004-2007 application.

45 Details on the deferral account balances and their allocation to customers for 2007, 2006, 2005, 2004, 2003, and prior years are provided in the included appendices.

The deferral account reconciliations, prior year adjustments, and allocations to customers provided in the body and appendices of this application have been prepared using a

software program developed by the AESO ~~in~~from 2006 ~~and~~to 2007 specifically for this purpose. The AESO believes the extra time taken to develop the program ~~and~~used to prepare ~~this~~the original and this revised application has allowed more effective handling of the large quantity of data involved in multi-year deferral account reconciliations. The AESO expects the development of the program will allow future deferral account reconciliation applications to be prepared and filed more efficiently than would otherwise be possible.

## 1.2 Immediate Interim Settlement With Customers

As discussed previously, the AESO's deferral account balances increased materially in late 2007 and early 2008, after the filing of the 2004-2005 Deferral Account Reconciliation Application. In examining alternatives to address these unexpected increases, the AESO considered different approaches which could enable a prompt and accurate settlement of the outstanding deferral account balances.

The AESO concluded that filing a revised and extended 2004-2007 application was appropriate, where the application included a request for interim approval to immediately settle deferral account amounts with customers. The purpose of requesting the immediate settlement is to clear the outstanding deferral account balances to the greatest extent possible without further delay. It would, at the same time, be interim and refundable, subject to adjustment in the final decision on the 2004-2007 application following a full regulatory review.

The deferral account balances in this extended 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 \$51.1 million net balance reconciled in this application represents a probable and material amount, and this is one reason it is appropriate to request interim approval.

The allocation of deferral account balances to customers has been prepared in this extended application using the same methodology as in the original application. No material concerns were raised with that methodology during either the technical meeting or through the information requests on the original 2004-2005 application. The AESO therefore considers that the allocation in this application will be found to be reasonable. The allocation should therefore result in rate stability and intergenerational equity, and this is another reason interim approval is appropriate.

One aspect of this application not included in the original 2004-2005 application is the redistribution of interest on deferral account balances. This matter was discussed with stakeholders in April 2008 but did not receive consensus support from all parties as summarized in section A-13 of Appendix A. This application nevertheless includes redistribution of interest for reasons discussed in more detail in section 2.3 of this application. The redistribution of interest does not change the overall deferral account balance, and simply affects the allocation of about 6% (\$2.9 million) of the \$51.1 million net balance being settled in this application. On balance, the AESO considers that including redistribution of interest is a reasonable approach and more likely to result in

intergenerational equity, and therefore contributes to the reasons interim approval is appropriate in this case.

Based on the above, immediate interim settlement will fulfill the objectives of 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 accordingly includes a request for approval of immediate interim settlement of deferral account balances with customers in section 1.4 below.

### **1.3 Organization of This Application**

This application is organized into the following sections:

- 1 Application** — Provides background on the application and specifies the relief requested.
- 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.
- 3 2007 Financial Results and Deferral Account Balance** — Discusses cost and revenue variances for 2007 and provides the deferral account balance for 2007.
- 4 2006 Financial Results and Deferral Account Balance** — Discusses cost and revenue variances for 2006 and provides the deferral account balance for 2006.
- 5 2005 Financial Results and Deferral Account Balance** — Discusses cost and revenue variances for 2005 and provides the deferral account balance for 2005.
- ~~4~~–**6** 2004 Financial Results and Deferral Account Balance** — Discusses cost and revenue variances for 2004 and provides the deferral account balance for 2004.
- ~~5~~–**7** 2003 Financial Results and Deferral Account Balance** — Discusses adjustments to costs and revenues that occurred after the first 2003 deferral account reconciliation and provides the outstanding deferral account balance for 2003.
- ~~6~~–**8** Pre-2003 Deferral Account Adjustments** — Discusses adjustments to costs and revenues included in this application that relate to 1999 through 2002 inclusive and provides the outstanding deferral account balances for those years.
- ~~7~~–**9** Allocation to Customers** — Discusses the process by which deferral account balances are allocated to customers.
- ~~8~~–**10** Proposed Method of Refunding and Collecting** — Discusses the proposed method of refunding and collecting deferral account amounts.
- ~~9~~–**11** Responses to Directions** — Provides responses to outstanding directions from EUB Decision 2005-034 and from the AUC's letter of April 16, 2008.

Appendices A through MN provide additional detail in support of the application, including customer level allocation of deferral account balances. In particular, Appendix A provides a summary of conclusions reached during stakeholder consultation in 2004 ~~and~~, 2005, and 2008.

### 1.34 Relief Requested

This application addresses matters raised in the deferral account reconciliation applications for 2000-2002 and for 2003, and additional matters raised during consultation with stakeholders in 2004 ~~and~~, 2005, and 2008. The AESO expects that the comprehensive nature of this application should improve the efficiency of the regulatory review process. The AESO therefore suggests this application be subject to an expedited approval, through a written proceeding.

Based on the entirety of this application, and for the foregoing ~~discussion~~reasons, the AESO requests:

(a) Approval of the deferral account balance reconciliation calculations for the period January 1 to December 31, ~~2005~~2007 as described in section 3 of this application;

(b) Approval of the deferral account balance reconciliation calculations for the period January 1 to December 31, ~~2004~~2006 as described in section 4 of this application;

(c) Approval of the deferral account balance reconciliation calculations for the period January 1 to December 31, ~~2003~~2005 as described in section 5 of this application;

(d) Approval of the deferral account balance reconciliation calculations for the period January 1 to December 31, 2004 as described in section 6 of this application;

(e) Approval of the deferral account balance reconciliation calculations for the period January 1 to December 31, 2003 as described in section 7 of this application;

(f) Approval of the deferral account adjustment calculations for the period January 1, 1999 to December 31, 2002 as described in section ~~6~~8 of this application;

~~(g)~~ Approval of the customer allocation methodology as presented in section ~~7~~9 and Appendices H through ML of this application, for purposes of recovering and refunding outstanding variance amounts from and to the AESO's DTS and STS rate classes;

(h) Approval to collect and refund amounts through use of a one-time payment/collection option similar to that used for previous years' deferral account balances as more particularly described in section ~~8~~10 of this application;

(gi) 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;

5 (i) 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);

10 (k) Confirmation ~~from~~by the EUBAUC of its acceptance of the AESO's responses to outstanding directions provided in section 911; and

(h) Such further and other relief as the EUBAUC may prescribe.

15 All of which is respectfully submitted this ~~1st~~2nd day of ~~December, 2007~~June, 2008.

Alberta Electric System Operator

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

## 2 SUMMARY OF DEFERRAL ACCOUNT RECONCILIATION PROCESS

The deferral account reconciliation process used for this application reflects prior EUBAUC decisions, conclusions reached during extensive stakeholder consultation, and development and use of a software program to automate deferral account reconciliation calculations.

Several aspects of the deferral account reconciliation process affected by the decisions, consultation, and software development are described in the following sections.

### 2.1 Data Included in This Application

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 2005-2007 or prior years for all costs except those related to losses, and to 2005 and prior years for costs related to losses; and
- were accounted for up to JulyMarch 31, 20072008.

Specifically, and as described in more detail later in this section, the following data is included for the different components of this application:

(a) **2007 First 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 March 31, 2008. The reconciliation includes all 2007-related costs and revenues settled during calendar year 2007, as well as all adjustments relating to 2007 which occurred on or after January 1, 2008 and up to March 31, 2008, which result in a 2007 deferral account balance surplus of \$2.0 million.

(b) **2006 First 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 March 31, 2008. The reconciliation includes all 2006-related costs and revenues settled during calendar year 2006, as well as all adjustments relating to 2006 which occurred on or after January 1, 2007 and up to March 31, 2008, which result in a 2006 deferral account balance surplus of \$11.3 million.

(c) **2005 First Reconciliation** — This application reconciles all costs paid and revenues collected by the AESO with respect to 2005, including losses, from January 1, 2005 to JulyMarch 31, 20072008. The reconciliation includes all 2005-related costs and revenues settled during calendar year 2005, as well as all adjustments relating to 2005 which occurred on or after January 1, 2006 and up to JulyMarch 31, 20072008, which result in a 2005 deferral account balance shortfall of \$6.80.9 million.

(d) **2004 First Reconciliation** — This application reconciles all costs paid and revenues collected by the AESO with respect to 2004, including losses, from January 1, 2004 to JulyMarch 31, 20072008. The reconciliation includes all 2004-related costs and

revenues settled during calendar year 2004, as well as all adjustments relating to 2004 which occurred on or after January 1, 2005 and up to ~~July~~~~March~~ 31, ~~2007~~~~2008~~, which result in a 2004 deferral account balance shortfall of \$~~4.15.3~~ million.

5 (ee) **2003 Second Reconciliation** — This application reconciles all costs paid and revenues collected by the AESO with respect to 2003, ~~including losses~~, from ~~January~~~~January~~ 1, 2003 to ~~July~~~~March~~ 31, ~~2007~~~~2008~~. The AESO notes that its previous 2003 deferral account reconciliation application included all 2003-related costs and revenues settled during calendar year 2003, as well as:

- 10
- all adjustments to losses costs and revenues relating to 2003 which occurred on or after January 1, 2004 and up to August 31, 2004; and
  - all adjustments to costs and revenues other than losses relating to 2003 which occurred on or after January 1, 2004 and up to January 31, 2004.

15 This current application also incorporates all later adjustments relating to 2003 which occurred, for losses, on or after September 1, 2004 and up to ~~July~~~~March~~ 31, ~~2007~~~~2008~~, and, for other costs and revenues, on or after February 1, 2004 and up to ~~July~~~~March~~ 31, ~~2007~~~~2008~~, which result in a 2003 deferral account balance ~~shortfall of \$11.0~~~~surplus of \$42.1~~ million.

20 (df) **Allocation of Prior Year Adjustments** — Finally, this application allocates to customers:

- 25
- all deferral account balance adjustments to losses costs and revenues relating to 1999, 2000, 2001, and 2002 which occurred on or after September 1, 2004 and up to ~~July~~~~March~~ 31, ~~2007~~~~2008~~; and
  - all deferral account balance adjustments to costs and revenues other than losses relating to 1999, 2000, 2001, and 2002 which occurred on or after February 1, 2004 and up to ~~July~~~~March~~ 31, ~~2007~~~~2008~~.

30 As well, any adjustments relating to 1999-2002 which were included in the 2003 deferral account reconciliation have been reallocated in accordance with the process for prior year adjustments utilized in this application. The net impact of prior year adjustments is a deferral account balance surplus of \$~~36.84~~ million.

35 ~~Any adjustments occurring on or after August 1, 2007 are not included in this application, and will be addressed in a future deferral account reconciliation application.~~  
**2.1.1 Significant Prior Period Adjustments**

40 ~~The AESO also notes that This application includes several significant amounts that were attributed to prior periods under the production month presentation used in this application. The following amounts were the subject of discussion with stakeholders during consultation and during the 2004-2005 deferral account reconciliation application review discussed in section 1.1 of this application.~~  
~~includes:~~

- the \$24.2 million ~~adjustment~~~~refund accounted for in May 2005 and~~ relating to 2001-2003 losses identified in the AESO's 2005-2006 General Tariff Application proceeding (discussed in more detail in section 7.2.2);

- the \$6.2 million refund accounted for in March 2008 and relating to Transmission Administrator (TA) Adjustments reflecting 2001-2005 changes to point-of-delivery meter volumes (discussed in more detail in section 5.1.3);
- the \$19.2 million refund accounted for in December 2007 and relating to adjustments to 2003-2007 ATCO Electric TFO costs, including a \$16.1 million refund with respect to ATCO Electric's tax liability refiling addressed in AUC Decision 2007-104 (discussed in more detail in section 3.1.1), a \$1.5 million charge to the AESO with respect to ATCO Electric's 2005 deferral account addressed in AUC Decision 2007-071 (discussed in more detail in section 5.1.1), and a \$4.6 million refund with respect to ATCO Electric's 2006 deferral account addressed in AUC Order U2007-256 (discussed in more detail in section 4.1.1); and
- a \$2.1 million charge accounted for in March 2008 and relating to TMR services from the Rainbow Lake facilities originally conscripted under an interim arrangement and finalized under a commercial agreement in accordance with AUC Decision 2008-014 (discussed in more detail in section 3.1.2).

### **2.1.2 Transmission System Losses**

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 2007 and 2006 deferral account years in this application.

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. Such pre-2006 adjustments continue to be addressed through the annual retrospective reconciliations for those years in this application.

Revenue and cost adjustments related to losses continue to be attributed to a production month, and when the production month was prior to January 2006, the adjustments have been included in this retrospective reconciliation application. Where the production month was January 2006 or later the adjustments have been or will be addressed through prospective Rider E.

### **2.1.3 Adjustments Not Included**

Any adjustments relating to 2007 or prior years which occurred on or after March 31, 2008 are not included in this application, and will be addressed in a future deferral account reconciliation application.

For example, AUC Decision 2008-014 approving the AESO's Ancillary Services Article 11 Negotiated Settlement will result in costs for unforeseeable TMR services paid on an interim basis as far back as December 17, 2004 being reassessed under the pricing provision approved in that decision. The AESO expects that on the order of \$2 million of adjustments relating to these costs will occur in 2008 after March 31, 2008. The costs will therefore be

included in the AESO's 2008 deferral account reconciliation application, currently expected to be filed in early 2009.

## 2.2 Production Month Presentation

In Decision 2005-034 on the AESO's 2003 Deferral Account Reconciliation, the EUBAUC 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. (p. 9)*

In the 2003 Deferral Account Reconciliation proceeding, the EUBAUC 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, p. 10)

Consistent with the 2003 Deferral Account Reconciliation-this ruling, all revenues and costs included in this application for 2007, 2006, 2005, 2004, and 2003 are presented on a production month basis in this application. 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.

The first exception to the production month presentation of costs for 2003, 2004, and 2005 through 2007 is "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 only about 5% of the AESO's annual revenue requirement, 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.

The second exception to the production month presentation of revenues for 2003, 2004, and 2005 through 2007 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 applied as well as accumulated balances from prior quarters. They typically charge or refund amounts relating to two or three quarters. However, in this application, 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.

5 Prior year adjustments relating to 1999, 2000, 2001, and 2002 have also been treated on a production basis, by year for 1999-2001 and by month for 2002. Although the deferral  
~~account reconciliations for those years were originally performed on an accounting basis, the adjustments relating to those years have been treated on a production basis consistent with the current reconciliation methodology. The AESO considers it impractical to revisit those years and convert the original reconciliation from accounting month to production month. Prior period adjustments total about \$37 million over all four years, accounting for only about 4% of the AESO's annual revenue requirement.~~

10  
~~Finally, adjustments relating to 1999 and 2000 are extremely small, totaling less than \$100,000 over both years. Those amounts have been included for allocation with the adjustments for 2001. This treatment greatly simplified the allocation of adjustments for 1999 and 2000, and was a practical approach to avoid dealing with very small amounts for those two years.~~

15  
~~In summary, revenues, costs, and adjustments for the different deferral account reconciliation years have been attributed as shown in Table 2-1.~~

20  
~~The method of allocating the deferral account balance for each of these years to customers is discussed in detail in section 7 of this application.~~

25  
**Table 2-1 Summary of Deferral Account Attribution Characteristics, 1999-~~2005~~2007**

Deferral Year	Reconciliation Basis	Adjustments Basis	Attribution Period	Allocation Year
<u>2007</u>	<u>production</u> <sup>1</sup>	<u>—</u> <sup>5</sup>	<u>month</u>	<u>2007</u>
<u>2006</u>	<u>production</u> <sup>1</sup>	<u>—</u> <sup>5</sup>	<u>month</u>	<u>2006</u>
2005	production <sup>1</sup>	— <sup>5</sup>	month	2005
2004	production <sup>1</sup>	— <sup>5</sup>	month	2004
2003	production <sup>2</sup>	— <sup>5</sup>	month	2003
2002	accounting <sup>3</sup>	production	month	2002
2001	accounting <sup>3</sup>	production	year	2001
2000	accounting <sup>3</sup>	production	year	2001
1999	accounting <sup>4</sup>	production	year	2001

Notes:

- <sup>1</sup> 2007, 2006, 2005, and 2004 first reconciliations are included in this application
- <sup>2</sup> 2003 second reconciliation is included in this application; 2003 first reconciliation was included in the AESO's Application of June 4, 2004 (refiled on December 14, 2004)
- <sup>3</sup> 2002, 2001, and 2000 first reconciliations were included in the AESO's Application of September 15, 2003; in that application all costs were reconciled on an accounting basis, except losses which were reconciled on a production basis
- <sup>4</sup> 1999 deferral account balances were included in ESBI Alberta Ltd.'s Application of October 2000
- <sup>5</sup> 2007, 2006, 2005, 2004, and 2003 adjustments are included in the reconciliations for those years in this application

5 account reconciliations for those years were originally performed on an accounting basis, the adjustments relating to those years have been treated on a production basis consistent with the current reconciliation methodology. The AESO considers it impractical to revisit those years and convert the original reconciliation from accounting month to production month. Prior period adjustments total about \$42.1 million over all four years, accounting for only about 5% of the AESO's average annual revenue requirement during that time.

10 Finally, adjustments relating to 1999 and 2000 are extremely small, totalling less than \$100,000 over both years. Those amounts have been included for allocation with the adjustments for 2001. This treatment greatly simplified the allocation of adjustments for 1999 and 2000, and was a practical approach to avoid dealing with very small amounts for those two years.

15 In summary, revenues, costs, and adjustments for the different deferral account reconciliation years have been attributed as shown in Table 2.1.

20 The method of allocating the deferral account balance for each of these years to customers is discussed in detail in section 9 of this application.

### 2.3 Redistribution of Interest

25 This application includes the recognition of interest on deferral account balances and its redistribution both between production months and between rate and rate components. This differs from the AESO's previous deferral account reconciliation applications which did not explicitly include any recognition of interest.

30 The AESO generally considers that interest is appropriately addressed through the "normal" determination of deferral account riders. However, the current application deals with several extraordinary circumstances, and the AESO considers that in this specific application it is appropriate to recognize and redistribute interest. The redistribution of interest does not change the overall deferral account balance, but deems interest to have accrued on monthly balances and redistributes the accrued amounts according to the allocation of the associated balances as described in more detail below.

35 The AESO notes that it conducted a brief stakeholder consultation process on recognition of interest in April 2008. Stakeholders did not unanimously support the AESO's proposed approach, as discussed further in section A-13 of Appendix A of this application. The AESO reviewed stakeholder comments received during the consultation, and concluded the merits of recognizing interest outweighed concerns about doing so in these specific circumstances.

40 As background, a deferral account balance generally adds to (in the case of a shortfall) or reduces (in the case of a surplus) the bank debt balances held by the AESO. Bank debt provides the AESO with working capital due to the timing difference in the collection of revenue and the payment of expenses, and funds capital purchases by the AESO. Interest expense is incurred by the AESO as a result of bank debt, and a deferral account balance accordingly increases (in the case of a shortfall) or decreases (in the case of a surplus)

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interest expense. Interest expense is included in general and administrative costs and is allocated in the same manner as interconnection charges in the AESO's deferral accounts.

5 As explained in section 1.1 of this application, the AESO's tariff includes Riders B and C which allow the AESO to manage its deferral account balances throughout the year. In particular, Deferral Account Adjustment Rider C is applied on a forecast basis to "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." Rider C is generally expected to result in deferral account balances that are sometimes shortfalls and sometimes surpluses, and that average near zero over time within a reasonable range of forecast variance.

10 However, the deferral account balances during 2006, 2005, and 2004 frequently totalled a material surplus, as summarized in Table 2-2. During the three-year period, the total deferral account balance was a surplus for 29 months and a shortfall for only 7 months, and the average balance was \$11.3 million surplus. This resulted in large part from the AESO's decision to retain the \$24.2 million one-time refund accounted for in May 2005 related to losses incurred from 2001 to 2003, as discussed in section 7.2.2 of this application.

20 Table 2-2 Total Deferral Account Closing Surpluses (Shortfalls) by Month, 2004-2006, \$ 000 000

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
2006	\$25.7	\$38.1	\$40.5	\$37.8	\$27.2	\$17.0	\$8.4	\$11.9	\$12.0	\$0.4	\$1.9	\$7.5	\$19.0
2005	0.7	(7.1)	(8.3)	(7.3)	22.1	19.4	8.6	1.6	(7.0)	(4.1)	(1.0)	12.4	2.5
2004	16.7	11.1	23.9	(2.7)	6.0	9.1	14.2	17.5	21.4	18.5	8.0	3.6	12.3

Notes: The AESO's 2003 Deferral Account Reconciliation Application settled all prior amounts, resulting in an opening balance of \$0.0 million for January 2004

Additional information on deferral account balances by rate component is provided in Appendix G

25 The existence of material surpluses for extended periods of time reduced the AESO's interest expense as discussed above, which in turn reduced the general and administrative costs allocated to customers. General and administrative costs (including interest expense) are allocated in the same manner as interconnection charges in the AESO's deferral accounts, which for 2004 and 2005 was 58% to DTS customers and 42% to STS customers, and for 2006 and later years was 100% to DTS customers. The AESO considers that this "normal" treatment of interest expense results in two inappropriate results in this circumstance.

30 (a) First, adjustments which create deferral account surpluses or shortfalls frequently relate to prior periods, as in the case, for example, of the \$24.2 million losses refund in June 2005 which related to losses incurred from 2001 to 2003. Using the production month approach discussed in the preceding section of this application, a deferral account adjustment itself is allocated back to the relevant prior production months, but any interest expense impact remains in the accounting months. In effect, "accounting month" customers are impacted by deferral account balances attributed back to "production month" customers.

35 (b) Second, the interest expense impacts arising from deferral account adjustments are allocated in the same manner as the interconnection charge rate component, even

5 though the deferral account adjustments themselves may arise from any rate component — interconnection charge, losses charge (before 2006), operating reserve charge, voltage control charge (since 2006), and other system support services charge — and rate components other than interconnection charge are allocated on different bases. In effect, customers subject to the interconnection charge are impacted by deferral account balances attributed to other rate components.

10 The AESO considers that these two results of “normal” deferral account treatment of interest expense are inconsistent with the production month and rate component alignment of other costs, when material deferral account surpluses or shortfalls exist for extended periods of time. The AESO would not consider either of the results (misalignment in time or misalignment in rate component) to be material if deferral account balances averaged near zero on a forecast basis, or if deferral account balances were subject to a reconciliation application shortly after year-end. However, in the current application deferral account balances have remained in a surplus position for an extended period of time, and interest expense should therefore be redistributed to the appropriate production months and rate components to avoid the inconsistent results discussed above.

20 Consistent with this discussion, the AESO does not consider deferral account balances during 2007 should be subject to interest redistribution. The monthly deferral account balances for 2007, less the \$7.5 million closing balance surplus from December 2006, averaged only a \$0.9 million shortfall. As well, the AESO’s 2007 deferral accounts are reconciled in this application, which is being filed in the second quarter following year-end. As the deferral account balances averaged near zero over the year and the reconciliation is being filed within a reasonable time frame, the AESO concludes the 2007 amounts should not require interest redistribution.

30 The calculation of interest for redistribution does include the 2006 deferral account closing balances throughout 2007 and up to July 2008, however, as those balances have remained in the AESO’s deferral account and have reduced interest expense that would otherwise have been allocated to customers.

35 For additional guidance on the redistribution of interest, the AESO has taken into account AUC Rule 023 respecting payment of interest. The AESO’s recognition of interest is consistent with the following aspects of section 3(2) of Rule 023:

- 40 (b) the regulatory lag before implementation of the rate adjustment must exceed a period of twelve months;
- (c) for general utility rates, the minimum amount of the forecast aggregate change in revenue shall ordinarily be the greater of ±\$1,000,000 or ±3% of the revenue from the rates being revised...;
- (d) interest will be calculated from the date on which the rate adjustment becomes effective;
- 45 (e) interest will be calculated using a rate equal to the Bank of Canada’s Bank Rate plus 1½%....

The recognition of interest based on these principles results in the redistribution of interest amounts between production years and rates as provided in Table 2-3. The deferral account

surpluses which existed in 2004 and later years resulted in interest expense reductions which have been attributed back to the same production months to which the deferral account surpluses were attributed. The interest expense in the accounting months in 2004 and later years has accordingly increased with the attribution of the interest expense reduction to prior production months.

The interest expense production month adjustments have also been allocated to the same rates and rate components to which the deferral account surpluses were attributed. At the same time, the interest expense accounting month adjustments have been allocated to the same rates and rate components as interconnection charges.

Additional detail is provided in Appendix G of this application.

Table 2-3 Redistribution of Interest, \$ 000 000

<u>Year</u>	<u>Increase (Decrease) in Interest Expense</u>			<u>Allocation to Customers</u>	
	<u>Calculation by Accounting Month</u>	<u>Redistribution by Production Month</u>	<u>Net Annual Increase (Decrease)</u>	<u>DTS</u>	<u>STS</u>
<u>2008</u>	<u>\$0.2</u>	<u>-</u>	<u>\$0.2</u>	<u>\$0.2</u>	<u>-</u>
<u>2007</u>	<u>0.5</u>	<u>-</u>	<u>0.5</u>	<u>0.5</u>	<u>-</u>
<u>2006</u>	<u>1.1</u>	<u>0.9</u>	<u>2.0</u>	<u>2.0</u>	<u>-</u>
<u>2005</u>	<u>0.1</u>	<u>1.2</u>	<u>1.3</u>	<u>0.6</u>	<u>0.6</u>
<u>2004</u>	<u>0.5</u>	<u>(0.4)</u>	<u>0.1</u>	<u>(1.3)</u>	<u>1.4</u>
<u>2003</u>	<u>-</u>	<u>(1.7)</u>	<u>(1.7)</u>	<u>1.0</u>	<u>(2.7)</u>
<u>2002</u>	<u>-</u>	<u>(2.3)</u>	<u>(2.3)</u>	<u>(0.0)</u>	<u>(2.3)</u>
<u>Total</u>	<u>\$2.4</u>	<u>(\$2.4)</u>	<u>-</u>	<u>\$2.9</u>	<u>(\$2.9)</u>

Note: Numbers may not add due to rounding.

The AESO does not expect that redistribution of interest will be required in future deferral account reconciliation applications. As discussed in section 2.8 of this application, the AESO intends to file future deferral account reconciliation applications on an annual basis, in the second calendar quarter following the year to which the deferral account relates. The AESO considers that such filings would avoid material inconsistencies in production month and rate component alignment of interest expense amounts.

#### 2.4 Deferral Account Balances for 1999 to 2005 2007

Table 2-24 summarizes the deferral account balances and adjustments addressed in this application for deferral account years from 1999 to ~~2005~~2007.

Variances between revenues and costs before Rider C collections or refunds were:

- a shortfall of \$25,456.1 million or 8% of costs for 2007,
- a shortfall of \$3.7 million or 1% of costs for 2006,
- a shortfall of \$19.6 million or 2% of costs for 2005,
- a surplus of \$68,066.8 million or 10% of costs for 2004, and
- a surplus of \$108,121.5 million or 1517% of costs for 2003.

The ~~From 2003 through 2006, the AESO attributes the~~ observes a trend of general ~~reduction~~ reductions in the deferral account balance (before Rider C) ~~for 2005 compared to 2004, and for 2004 compared to 2003,~~ attributable to better alignment of costs and rate components in the 2004, 2005, and 2005/2006 approved tariffs, ~~and to~~ general process refinements, and improvements in initial settlement results. The 2007 shortfall arises in part from misalignment attributable to using rates based on 2006 costs to recover costs in 2007, and in part to a trend to lower discounts, and in some cases premiums, for operating reserves in recent years.

The 2007, 2006, 2005, 2004, and 2003 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. The net deferral account balances remaining after Rider C charges and refunds were:

- a ~~shortfall~~ surplus of \$6.82.0 million or 0.83% of costs for 2005/2007,
- ~~a shortfall~~ surplus of \$4.111.3 million or 0.1.6% of costs for 2004, and
- 2006,
- a shortfall of \$41.0.9 million or 0.1-% of costs for 2005,
- a shortfall of \$5.3 million or 0.8% of costs for 2004, and
- a surplus of \$2.0 million or 0.3% of costs for 2003.

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,
- EUBAUC decisions on TFO costs and other matters,

*Table 2-2 — Summary of 2004-2005 Deferral Account (DA) Reconciliation Application, \$ 000 000*

*Table 2-2 Summary of 2004-2005 Deferral Account (DA) Reconciliation Application, \$ 000 000*

	DA Reconciliations			DA Adjustments <sup>1</sup>				Totals
	2005	2004	2003	2002	2001	2000	1999	1999-2003
<b>Revenues</b>								
Interconnection	—431.4	—381.0	—393.5	—(0.6)	—(0.1)	—	—	
Losses	—180.7	—138.4	—216.5	—(1.2)	—(0.0)	—	—	
Operating Reserve	—217.2	—236.2	—237.9	—(0.0)	—0.0	—	—	
Other System Support	—2.4	—2.2	—2.2	—(0.1)	—(0.0)	—	—	
<b>Total Revenues</b>	<b>—831.8</b>	<b>—757.8</b>	<b>—850.1</b>	<b>—(1.9)</b>	<b>—(0.1)</b>	<b>—</b>	<b>—</b>	<b>—2,437.8</b>
<b>Costs Paid</b>								
Wires	—(429.6)	—(390.2)	—(368.8)	—15.9	—7.7	—0.1	—	
Ancillary Services	—(189.9)	—(126.1)	—(177.4)	—(0.7)	—(0.1)	—(0.1)	—(0.0)	
Losses	—(202.0)	—(142.2)	—(156.8)	—15.6	—0.2	—0.0	—	
Other Industry	—(5.3)	—(5.0)	—(9.3)	—0.0	—	—	—	
General & Administrative	—(30.3)	—(26.3)	—(29.4)	—0.0	—	—	—	
<b>Total Costs Paid</b>	<b>—(857.2)</b>	<b>—(689.8)</b>	<b>—(741.6)</b>	<b>—30.8</b>	<b>—7.8</b>	<b>—0.1</b>	<b>—(0.0)</b>	<b>—(2,249.9)</b>
<b>Deferral Account</b>								
Surplus (Shortfall)	—(25.4)	—68.0	—108.5	—29.0	—7.7	—0.1	—(0.0)	—187.9



Rider C Collection (Refund) <sup>2</sup>	<u>18.7</u>	<u>(72.1)</u>	<u>(119.5)</u>	<u>    </u>	<u>    </u>	<u>    </u>	<u>    </u>	<u>    </u>	<u>(172.9)</u>
Net Surplus (Shortfall)	<u>(6.8)</u>	<u>(4.1)</u>	<u>(11.0)</u>	<u>29.0</u>	<u>7.7</u>	<u>0.1</u>	<u>(0.0)</u>	<u>    </u>	<u>15.0</u>

Notes:

Numbers may not add due to rounding.

<sup>1</sup> Adjustments relating to the 1999-2002 deferral account years have been reconciled independently in this 2004-2005 Deferral Account Reconciliation Application and are no longer grouped as a "13th month" in 2003. These columns include all changes that have occurred since these deferral account years were originally filed.

<sup>2</sup> The \$38.5 million true-up related to the 2003 Deferral Account Reconciliation Application was fully applied to 2003 as a Rider C collection. This process allows for more accurate customer allocations for the years 1999-2002 given the new detailed deferral account reconciliation compared to the original 2003 Deferral Application filed in 2004 that grouped these years together as a 13th month in 2003.

- PFAM (Post Final Adjustment Mechanism) data restatements,
- vendor invoice corrections,
- revisions to contract terms, and
- revisions to rate calculations or application.



Table 2-4 Summary of 2004-2007 Deferral Account Reconciliation Application, \$ 000 000

	Deferral Account Reconciliations					Deferral Account Adjustments <sup>1</sup>				Totals
	2007	2006	2005	2004	2003	2002	2001	2000	1999	1999-2007
<b>Revenues</b>										
Interconnection	\$478.8	\$467.0	\$431.4	\$381.0	\$393.5	(\$0.6)	(\$0.1)	-	-	
Losses	-	-	180.7	138.4	216.5	(1.2)	(0.0)	-	-	
Operating Reserve	145.9	173.4	217.2	236.2	237.9	(0.0)	0.0	-	-	
Voltage Control	52.8	52.3	-	-	-	-	-	-	-	
Other System Support	8.0	7.9	2.4	2.2	2.2	(0.1)	(0.0)	-	-	
<b>Total Revenues</b>	<b>\$685.6</b>	<b>\$700.6</b>	<b>\$831.8</b>	<b>\$757.8</b>	<b>\$850.1</b>	<b>(\$1.9)</b>	<b>(\$0.1)</b>	<b>-</b>	<b>-</b>	<b>\$3,823.9</b>
<b>Costs Paid</b>										
Wires	(\$459.4)	(\$434.3)	(\$428.7)	(\$390.5)	(\$358.1)	\$15.8	\$7.7	\$0.1	-	
Ancillary Services	(232.7)	(233.0)	(189.7)	(123.7)	(177.5)	(0.7)	(0.1)	(0.1)	(0.0)	
Losses	-	-	(196.1)	(145.5)	(156.2)	16.6	2.2	0.0	-	
Other Industry	(4.8)	(3.6)	(5.3)	(5.0)	(9.3)	0.0	-	-	-	
General & Administrative	(44.8)	(33.4)	(31.6)	(26.4)	(27.7)	2.3	-	-	-	
<b>Total Costs Paid</b>	<b>(\$741.7)</b>	<b>(\$704.3)</b>	<b>(\$851.4)</b>	<b>(\$691.1)</b>	<b>(\$728.7)</b>	<b>\$34.1</b>	<b>\$9.8</b>	<b>\$0.1</b>	<b>(\$0.0)</b>	<b>(\$3,673.1)</b>
<b>Deferral Account</b>										
Surplus (Shortfall)	(56.1)	(3.7)	(19.6)	66.8	121.5	32.3	9.7	0.1	(0.0)	150.8
Rider C Collection (Refund) <sup>2</sup>	58.1	15.1	18.7	(72.1)	(119.5)	-	-	-	-	(99.8)
<b>Net Surplus (Shortfall)</b>	<b>\$2.0</b>	<b>\$11.3</b>	<b>(\$0.9)</b>	<b>(\$5.3)</b>	<b>\$2.0</b>	<b>\$32.3</b>	<b>\$9.7</b>	<b>\$0.1</b>	<b>(\$0.0)</b>	<b>\$51.1</b>

Notes:

Numbers may not add due to rounding.

<sup>1</sup> Adjustments relating to the 1999-2002 deferral account years have been reconciled independently in this 2004-2007 Deferral Account Reconciliation Application and are no longer grouped as a "13th month" in 2003. These columns include all changes that have occurred since these deferral account years were originally filed.

<sup>2</sup> The \$38.5 million true-up related to the 2003 Deferral Account Reconciliation Application was fully applied to 2003 as a Rider C collection. This process allows for more accurate customer allocations for the years 1999-2002 given the new detailed deferral account reconciliation compared to the original 2003 Deferral Application filed in 2004 that grouped these years together as a 13th month in 2003.

Where adjustments relate to a calendar year prior to the years being reconciled or re-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 (or years, for 1999 to 2001), as discussed in section 2.2 of this application.

This application includes the following prior period adjustment amounts as summarized in Table 2-24:

- for 2002, a surplus of \$29.032.3 million,
- for 2001, a surplus of \$79.7 million,
- for 2000, a surplus of \$0.06 million, and
- for 1999, a shortfall of \$0.003 million.

The variances between revenues and costs and the prior period adjustments included in Table 2-24 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 when a deferral account is subject to full reconciliation as for 2007, 2006, 2005, 2004, and 2003. (Non-material prior period adjustments are allocated using previously-approved allocators which would not be affected by adjustments to revenues, as discussed in section A-9 of Appendix A of this application.)

The final allocations to individual customers therefore result from both deferral account balances and individual customer revenues. The allocations to individual customers for 2007, 2006, 2005, 2004, 2003, 2002, and 2001 are provided in Appendices H, J, K, L, and M of this application, respectively.

For comparison with Table 2-24, Table 2-35 provides a summary of similar amounts as included in the AESO’s 2003 deferral account reconciliation application. The 1999-2002 adjustments from the 2003 first reconciliation (as summarized in Table 2-35) differ from the 1999-2002 adjustments in this application (as summarized in Table 2-24) because of the additional transactions related to those years than have occurred since the data cut off date for the 2003 first reconciliation.

In addition, “Other Industry” costs are treated differently in this application than in the 2003 first reconciliation. Other industry costs consist of external regulatory costs, Western Electricity Coordinating Council (WECC) membership costs, and the AESO’s share of EUBAUC operating costs. In the 2003 first reconciliation, external regulatory costs were attributed to the year or years to which the regulatory proceeding was deemed to be relevant. In this application, those costs are treated on an accounting month basis, consistent with other “own costs” as discussed in section 2.2 of this application. This recognizes, for example, that even though a regulatory proceeding occurs in a particular year, it may relate to multiple years or the resulting decision may not be implemented until the following year. The result of this change in treatment is that about \$8 million of external regulatory costs which were attributed to 2002 and 2001 in the 2003 first reconciliation are now attributed to 2003 in this application.





Table 2-35 Summary of 2003 Deferral Account Reconciliation Application (Filed December 2004), \$ 000 000

	DA Reconciliation Deferral Account Reconciliations						Prior-Period Deferral Account Adjustments <sup>1</sup>	Totals
	2005	2004	2003	2002	2001	2000	1999	
<b>Revenues</b>								
Interconnection			—397.3	—(0.1)	—	—	—	
Losses			—216.2	—(1.0)	—(0.0)	—	—	
Operating Reserve			—238.0	—0.1	—	—	—	
Other System Support			—2.3	—(0.0)	—	—	—	
<b>Total Revenues</b>			<b>—853.9</b>	<b>—(1.0)</b>	<b>—(0.0)</b>	<b>—</b>	<b>—</b>	<b>—852.8</b>
<b>Costs Paid</b>								
Wires			—(342.7)	—(0.6)	—0.5	—	—	
Ancillary Services			—(177.7)	—(0.7)	—(0.1)	—(0.1)	—(0.0)	
Losses			—(173.3)	—0.2	—0.0	—	—	
Other Industry			—(0.8)	—(6.2)	—(2.4)	—	—	
General & Administrative			—(29.4)	—0.0	—	—	—	
<b>Total Costs Paid</b>			<b>—(724.0)</b>	<b>—(7.4)</b>	<b>—(1.9)</b>	<b>—(0.1)</b>	<b>—(0.0)</b>	<b>—(733.3)</b>
<b>Deferral Account</b>								
Surplus (Shortfall)			—129.9	—(8.4)	—(1.9)	—(0.1)	—(0.0)	—119.5
Rider C Collection (Refund) <sup>2</sup>			—(129.9)	—8.4	—1.9	—0.1	—0.0	—(119.5)
<b>Net Surplus (Shortfall)</b>			<b>—</b>	<b>—</b>	<b>—</b>	<b>—</b>	<b>—</b>	<b>—</b>

Notes:

Numbers may not add due to rounding.

<sup>1</sup> These adjustments are included in the “13th month” of 2003 in the 2003 Deferral Account Reconciliation Application filed in 2004.

<sup>2</sup> EUB Decision 2005-034.

## 2.4 — Cost Prudency Considerations

As confirmed by the AESO in response to Information Request BR.AESO-06 in the AESO’s 2003 Deferral Account Reconciliation proceeding, the AESO considers this application and related proceeding to be the proper venue for the consideration of the prudence of AESO costs incurred with respect to 2005 and 2004.



5

As well, where significant adjustments to 2003 costs are included, this application and related proceeding is also the proper venue for consideration of the prudence of those adjustments to 2003 costs. The AESO notes, however, that the prudence of AESO costs incurred with respect to 2003 and already included in the AESO's 2003 deferral account reconciliation application was considered in the 2003 proceeding, and should not be reviewed again. The presentation of a second reconciliation of the AESO's 2003 deferral account in this application does not imply that all costs relating to 2003 are again subject to review. Rather, the second reconciliation is provided to appropriately allocate all 2003-related costs to customers, not to re-examine the prudence of costs which have already been approved.

	<u>2007</u>	<u>2006</u>	<u>2005</u>	<u>2004</u>	<u>2003</u>	<u>2002</u>	<u>2001</u>	<u>2000</u>	<u>1999</u>	<u>1999-2007</u>
<b>Revenues</b>										
Interconnection					\$397.3	(\$0.1)	-	-	-	
Losses					216.2	(1.0)	(0.0)	-	-	
Operating Reserve					238.0	0.1	-	-	-	
Voltage Control					-	-	-	-	-	
Other System Support					2.3	(0.0)	-	-	-	
<b>Total Revenues</b>					<b>\$853.9</b>	<b>(\$1.0)</b>	<b>(\$0.0)</b>	<b>-</b>	<b>-</b>	<b>\$852.8</b>
<b>Costs Paid</b>										
Wires					(\$342.7)	(\$0.6)	\$0.5	-	-	
Ancillary Services					(177.7)	(0.7)	(0.1)	(0.1)	(0.0)	
Losses					(173.3)	0.2	0.0	-	-	
Other Industry					(0.8)	(6.2)	(2.4)	-	-	
General & Administrative					(29.4)	0.0	-	-	-	
<b>Total Costs Paid</b>					<b>(\$724.0)</b>	<b>(\$7.4)</b>	<b>(\$1.9)</b>	<b>(\$0.1)</b>	<b>(\$0.0)</b>	<b>(\$733.3)</b>
<b>Deferral Account</b>										
Surplus (Shortfall)					129.9	(8.4)	(1.9)	(0.1)	(0.0)	119.5
Rider C Collection (Refund) <sup>2</sup>					(129.9)	8.4	1.9	0.1	0.0	(119.5)
<b>Net Surplus (Shortfall)</b>					<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>

Notes:

Numbers may not add due to rounding.

<sup>1</sup> These adjustments are included in the "13th month" of 2003 in the 2003 Deferral Account Reconciliation Application filed in 2004.

<sup>2</sup> AUC Decision 2005-034.



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## 2.5 Cost Prudence Considerations

5 As confirmed by the AESO in response to Information Request BR.AESO-06 in the AESO's 2003 Deferral Account Reconciliation proceeding, the AESO considers this application and related proceeding to be the proper venue for the consideration of the prudence of AESO costs incurred with respect to 2007, 2006, 2005, and 2004.

10 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, AR 86/2007. Forecast and actual losses costs and revenues for 2007 and 2006 are reported in the Rider E Calibration Factor Calculations provided in advance of each calendar quarter on the AESO web site, and are not further discussed in this deferral account reconciliation application. The Rider E Calibration Factor Calculations are available on the AESO's web site at [www.aeso.ca](http://www.aeso.ca) by following the path Transmission ► Loss Factors ► Calibration Factors.

15 Forecast and actual losses costs and revenues for 2005 and 2004 are included in this application, and are subject to review in the same manner as other amounts included in this deferral account reconciliation. As well, losses-related adjustments which have occurred since 2006 but which relate to 2005 and 2004 production months are included in this application and are subject to review in the related proceeding.

20 Where significant adjustments to 2003 costs are included in this deferral account reconciliation, this application and related proceeding is also the proper venue for consideration of the prudence of those adjustments to 2003 costs. The AESO notes, however, that the prudence of AESO costs incurred with respect to 2003 and already included in the AESO's 2003 deferral account reconciliation application was considered in the 2003 proceeding, and should not be reviewed again. The presentation of a second reconciliation of the AESO's 2003 deferral account in this application does not imply that all costs relating to 2003 are again subject to review. Rather, the second reconciliation is provided to appropriately allocate all 2003-related costs to customers, not to re-examine the prudence of costs which have already been approved.

25 Finally, where significant adjustments to 2002 and prior year costs are included, the proceeding related to this application is the proper venue for consideration of the prudence of those adjustments to such costs.

30 The AESO has accordingly provided schedules and explanations of significant variances by line item for 2007, 2006, 2005, and 2004, and of significant adjustments to costs for 2003 and for prior years where such adjustments have not previously been included in a deferral account reconciliation application, in section 3, 4, 5, 6, 7, and 68 of this application.

## 2.56 Reconciliation to Annual Reports

5 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 annual reports include or accrue for only those 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.

10 Therefore, revenues, costs, and deferral account balances included in this application have been reconciled to the revenues and costs reported in the audited income statements and balance sheets of the AESO for 2007, 2006, 2005, 2004, and 2003, and are provided in Appendices B and C of this application. ~~As well, where revenues, costs, and deferral account balances for 2005, 2004, and 2003 are affected by transactions that occurred in 2006, those amounts have been reconciled to the audited income statement and balance sheet of the AESO for 2006, also provided in Appendices B and C.~~

15  
20 The AESO's annual reports for 2007, 2006, 2005, 2004, and 2003 are provided in Appendix Appendix D.

## 2.67 Allocation to and Settlement With Customers

25 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.

30 Regulated distribution utilities will normally include their deferral account refunds and collections in their own tariff applications to the EUBAUC 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 this application.

35 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.

40 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 9.3 of this application.

## 45 2.78 Future Deferral Account Reconciliations

5 The AESO notes that effective January 1, 2006, transmission system losses will no longer be subject to retrospective deferral account reconciliation as has occurred for original 2004-2005 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 2007 Transmission Regulation, AR 86/2007. The AESO will therefore not include reconciliation of Rider E amounts for 2006 and subsequent years in future deferral account reconciliation applications.

10 Although transmission system losses have been subject to prospective Rider E since January 1, 2006, the AESO expects adjustments relating to years prior to 2006 will occur into the future. The AESO proposes that such pre-2006 adjustments continue to be addressed through annual retrospective reconciliations with respect to those years, as discussed in the preceding sections.

15 Revenue and cost adjustments related to losses will continue to be attributed to a production month. When the production month is prior to January 2006, the adjustments will be included in an annual retrospective reconciliation application. Where the production month is January 2006 or later the adjustments will be addressed through prospective Rider E.

20 The AESO notes that continued treatment of prior year loss adjustments through retrospective reconciliation will likely be subject to materiality thresholds as discussed in Appendix A of this application.

25 This deferral account reconciliation application has been was filed significantly later than was expected when the AESO consulted with stakeholders in 2004 and 2005. The initial delay of that application was to allow for a data cut-off several months after the end of the 2004 deferral account year. The inclusion of the re-reconciliation of the 2003 deferral account, as well as the attribution to production months or years of adjustments relating to several prior years, added to the complexity of the application and to the time required to compile and analyze financial and customer data. The AESO accordingly determined that the development and implementation of a software program would allow more effective handling of the large quantity of data involved in multi-year deferral account reconciliations. Although the delay has been was longer than anticipated, this resulting application is comprehensive and should improve the efficiency of the regulatory review process comprehensively addresses all deferral account amounts relating to 2005 and prior years.

40 Because of the legislative change which excludes transmission system losses from deferral account reconciliation effective January 1, 2006, the AESO decided to not include a 2006 deferral account reconciliation as part of this As discussed in section 1.1, the 2004-2005 application. However, the AESO plans to file the reconciliation for 2006 soon after filing this- originally filed on December 1, 2007, was suspended on April 16, 2008, to be replaced with this extended 2004-2007 application, and will base the 2006. The software program developed for the original application allowed the same data cut-off date addition of July 31, 2007. This will allow for an efficient filing

~~process that avoids filing adjustments to prior years based on a limited number of additional months of adjustment transactions.~~

5 ~~At this time, the AESO proposes to file the 2006 deferral account reconciliation and 2006 to the reconciliation relatively easily, allowing this extended application after information requests have been answered on this 2004-2005 to comprehensively addresses all deferral account amounts relating to 2007 and prior years as of March 31, 2008, which should allow an efficient and complete regulatory review process.~~

10 ~~The AESO also notes that as part of the examination of the original 2004-2005 deferral account reconciliation application, in order to enable incorporation, where appropriate, of matters raised during the information request process.~~

15 ~~The AESO the AESO assessed the effect of changes to transmission billing volumes for load customers between initial, interim, and final settlements. The AESO found the volume changes to be minimal, and expects that the resulting changes in deferral account allocation would then expect be expected to file be below the 2007 and subsequent annual ±\$50,000 materiality threshold for individual customer revenues discussed in section A-4 of Appendix A of this application.~~

20 ~~Therefore, based on the quality of initial settlement data, the AESO proposes to prepare future retrospective deferral account reconciliation applications in fall after initial settlement of December volumes. Historically, the year AESO has waited for final settlement of December data (which occurs in the following the deferral account year. At this time the AESO expects to use an August 31 cut-off date in accordance with the conclusion reached during stakeholder consultation, as discussed in Appendix A of this application. This approach will be reviewed prior to preparing the 2007-) before beginning preparation of a deferral account reconciliation application, to consider any relevant comments arising in the current and 2006 . The AESO believes that preparing future applications based on initial settlement volumes would have minimal impact on the accuracy of deferral account allocations to customers.~~

35 ~~Accordingly, the AESO intends to file its 2008 and 2009 deferral account reconciliation applications in the second calendar quarter of the year following the deferral account reconciliation proceedings year. The AESO will use a data cut-off date in the first calendar quarter of the year, for transactions to be included in that application.~~



5 As further discussed in section A-8 of Appendix A of this application, the AESO proposes to consult with stakeholders in early 2009, after the AUC issues its final decision on the extended 2004-2007 application. The consultation will consider:

- when and on what basis full reconciliations should be permanently discontinued for a deferral account year; and
- whether a prospective methodology could be implemented for the AESO's deferral accounts.

10 If the consultation results in recommendations for revisions to Rider B or C, such revisions would be proposed as part of the AESO's next General Tariff Application or in a separate rider amendment application if appropriate.

### 3 2007 FINANCIAL RESULTS AND DEFERRAL ACCOUNT BALANCE

5 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*, AR 86/2007. Therefore, the financial results and deferral account balance for 2007 discussed in this section do not include costs and revenues related to losses.

10 In determining the financial results and deferral account balance for 2007, all other revenue and cost transactions that occurred from January 1, 2007, to March 31, 2008 and that relate to 2007 have been included in the reconciliations. These transactions establish the 2007 production month data for deferral account reconciliation purposes in this application. The net result of these transactions is \$741.7 million in costs and \$743.7 million in customer revenues (including Rider C collections and refunds) being attributed to 2007.

15 The AESO notes that revenue and cost transactions that occurred from January 1, 2007, to March 31, 2008 may also relate, in whole or in part, to years prior to 2007. 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. Where the transaction (or part of the transaction) relates to losses prior to 2006, it also has been assigned to the prior year. Detail on the assignment between 2007 and prior years for transactions which occurred in 2007 and 2008 is provided in Appendix E-1 of this application.

#### 3.1 2007 Cost Variances

20 Table 3-1 presents the AESO's 2007 revenue requirement (excluding losses) as approved in AUC Decision 2008-037 on the AESO's 2007 General Tariff Application Refiling, dated May 8, 2008. Additional information on the AESO's 2007 revenue requirement is contained in AUC Decision 2007-106 on the AESO's 2007 General Tariff Application, dated December 21, 2007, as well as in the AESO's 2007 General Tariff Application itself available on the AESO web site at [www.aeso.ca](http://www.aeso.ca) by following the path Tariff ► Current Applications ► 2007 Tariff Application (Application 1485517).

25 Table 3-1 also includes recorded costs as incurred for 2007, and variances between approved and recorded costs in both dollar amounts and as a percentage of approved costs.

30 Total 2007 recorded costs are \$52.0 million (8%) higher than the total 2007 approved revenue requirement. This variance consists of 2007 recorded costs being:

- \$0.9 million (0.2%) higher than the 2007 approved revenue requirement for wires,
- \$48.3 million (26%) higher for ancillary services,
- \$0.7 million (13%) lower for other industry costs, and
- \$3.5 million (9%) higher for general and administrative costs.

**Table 3-1 2007 Revenue Requirement and Recorded Costs (Excluding Losses), \$ 000 000**

Line No.		Approved Forecast	Recorded Costs	Variance Over (Under)	
		(a)	(b)	\$ (c)=(b)-(a)	% (d)=(c)÷(a)
<b>WIRES</b>					
<b>TFO Wires-Related Costs</b>					
1	AltaLink	208.0	208.0	-	-
2	ATCO Electric Ltd.	169.5	169.5	-	-
3	Isolated Generation	(7.9)	(5.9)	2.0	(25.6%)
4	Subtotal ATCO Costs	161.6	163.6	2.0	1.2%
5	Enmax Power Corporation	31.9	31.9	-	-
6	EPCOR Transmission Inc.	36.8	36.8	-	-
7	City of Lethbridge	4.4	4.4	-	-
8	TransAlta	4.2	4.2	-	-
9	Refund to the AESO	-	-	-	-
10	Subtotal TransAlta Costs	4.2	4.2	-	-
11	City of Red Deer	1.7	1.7	-	-
12	FortisAlberta Networks (Farm)	1.5	1.5	-	-
13	Subtotal TFO Wires-Related Costs	450.0	452.1	2.0	0.4%
<b>Non-Wires Costs</b>					
14	Invitation to Bid on Credits (IBOC)	1.7	1.6	(0.1)	(5.3%)
15	Location Based Credit Standing Offer (LBC SO)	6.8	5.8	(1.0)	(15.4%)
16	Subtotal IBOC/LBC SO Costs	8.5	7.4	(1.1)	(13.4%)
17	TOTAL WIRES COSTS	458.5	459.4	0.9	0.2%
<b>ANCILLARY SERVICES</b>					
<b>Operating Reserves</b>					
Active					
18	Regulating	34.7	46.7	12.0	34.5%
19	Spinning	41.1	64.9	23.8	57.9%
20	Supplemental	32.0	56.1	24.1	75.2%
21	Subtotal Active Reserves	107.8	167.7	59.9	55.5%
Standby					
22	Regulating	4.6	6.2	1.6	35.8%
23	Spinning	5.7	8.8	3.1	55.2%
24	Supplemental	3.1	2.7	(0.4)	(12.3%)
25	Subtotal Standby Reserves	13.4	17.8	4.4	32.9%
26	Trading Fees & Other Related Charges	-	(4.8)	(4.8)	-
27	Subtotal Operating Reserves	121.2	180.7	59.5	49.1%
<b>Other Ancillary Services</b>					
28	Brazeau Fast Ramp (Previously GRAS)	0.6	0.6	0.0	1.6%
29	Black Start	2.8	2.0	(0.8)	(29.8%)
30	Transmission Must Run (TMR)	50.8	42.5	(8.3)	(16.4%)
31	Under Frequency Mitigation	5.9	5.0	(1.0)	(16.2%)
32	Subtotal Other Ancillary Services	60.2	50.1	(10.1)	(16.8%)

**Table 3-1 2007 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>Poplar Hill/ILRAS</b>					
33	Poplar Hill	1.9	2.0	0.1	5.5%
34	Interruptible Load Remedial Action Scheme (ILRAS)	0.7	0.0	(0.7)	(99.4%)
35	Generator Remedial Action Scheme (RAS)	0.5	-	(0.5)	(100.0%)
36	<b>Subtotal Poplar Hill/ILRAS</b>	<b>3.1</b>	<b>2.0</b>	<b>(1.1)</b>	<b>(35.2%)</b>
37	<b>TOTAL ANCILLARY SERVICES</b>	<b>184.5</b>	<b>232.8</b>	<b>48.3</b>	<b>26.2%</b>
<b>OTHER INDUSTRY COSTS</b>					
38	External Regulatory Costs	1.1	0.7	(0.4)	(32.0%)
39	Western Electricity Coordination Council (WECC)	2.2	1.8	(0.4)	(18.9%)
40	Share of AUC Overhead	2.2	2.3	0.1	3.4%
41	<b>TOTAL OTHER INDUSTRY COSTS</b>	<b>5.5</b>	<b>4.8</b>	<b>(0.7)</b>	<b>(12.6%)</b>
<b>GENERAL AND ADMINISTRATIVE COSTS</b>					
<b>Administrative Costs</b>					
42	Staff and Benefits	24.4	23.9	(0.5)	(1.9%)
43	Consultants	3.3	5.9	2.6	77.8%
44	Board Members Fees	0.4	0.3	(0.1)	(36.4%)
45	Travel and Training	1.1	1.2	0.1	8.8%
46	Legal	0.4	1.1	0.7	170.5%
47	Audits/Reviews	0.4	0.3	(0.1)	(31.7%)
48	Rent <sup>1</sup>	1.9	1.8	(0.1)	(6.5%)
49	Insurance	0.4	0.4	0.0	5.7%
50	Other Administrative Costs	1.5	1.7	0.2	15.5%
51	Telecomm and IT Maintenance	2.1	2.6	0.5	23.8%
52	Interconnection Fees (Offset)	(0.2)	(0.0)	0.2	(81.5%)
53	<b>Total Administrative Costs</b>	<b>35.7</b>	<b>39.1</b>	<b>3.4</b>	<b>9.5%</b>
<b>General Costs</b>					
54	Interest	1.2	1.8	0.6	53.2%
55	Amortization and Depreciation	4.4	3.9	(0.5)	(11.8%)
56	Taxes	-	-	-	-
57	<b>Total General Costs</b>	<b>5.6</b>	<b>5.7</b>	<b>0.1</b>	<b>2.1%</b>
58	<b>TOTAL GENERAL &amp; ADMINISTRATIVE COSTS</b>	<b>41.3</b>	<b>44.8</b>	<b>3.5</b>	<b>8.5%</b>
59	<b>Total G&amp;A and Other Industry Costs</b>	<b>46.8</b>	<b>49.6</b>	<b>2.8</b>	<b>6.0%</b>
60	<b>TOTAL REVENUE REQUIREMENT</b>	<b>689.8</b>	<b>741.7</b>	<b>52.0</b>	<b>7.5%</b>
<b>CAPITAL</b>					
61	General Capital	4.2	3.9	(0.3)	(7.1%)
62	System Coordination Centre	-	0.2	0.2	-
63	<b>Total Capital</b>	<b>4.2</b>	<b>4.1</b>	<b>(0.1)</b>	<b>(2.4%)</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 2007 Recorded Costs on Line 46

5 Variances arise due to a number of factors, including finalization of TFO costs through AUC 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  $\pm\$4.0$  million, which represents approximately 10% of the \$41.3 million general and administrative costs component of the AESO's revenue requirement. A line item variance smaller than  $\pm\$4.0$  million is also considered significant when it is both at least  $\pm\$0.4$  million and at least  $\pm 10\%$  of the approved line item amount. The  $\pm\$0.4$  million threshold represents approximately 1% of the \$41.3 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.

10 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  $\pm\$0.4$  million or less than  $\pm 10\%$  (except where such variance is  $\pm\$4.0$  million or greater) explanations are not provided, as such variances are small enough that specific variance explanations are not required.

### 20 **3.1.1 Wires Costs**

25 The AESO's 2007 TFO wires costs forecast was based on TFO costs approved at the time of the AESO's 2007 tariff application (for the City of Lethbridge and the City of Red Deer) or during the course of the proceeding (for all other TFOs). These costs were comprehensively summarized in section 2.2 of the AESO's 2007 General Tariff Application filed on November 3, 2006, and in response to Direction 1 in the AESO's 2007 GTA Refiling on February 1, 2008.

30 The recorded 2007 wires costs were as billed by the TFOs to the AESO based on the final or interim 2007 tariffs approved for the TFOs. The AESO notes that final approval has not yet been issued for the 2007 TFO tariffs of Enmax Power Corporation and EPCOR Transmission. If those TFOs' final tariffs differ from the interim tariffs 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 tariffs are approved.

### 35 **Line 2 ATCO Electric**

40 Although not resulting in a variance for 2007, this deferral account reconciliation application includes refunds with respect to ATCO Electric's tax liability refiling addressed in AUC Decision 2007-104, as mentioned in section 2.1.1 of this application. Decision 2007-104 on ATCO Electric's 2007-2008 General Tariff Application Refiling approved a total of \$16.1 million resulting from compliance with Direction 38's requirement for ATCO Electric to refund future income taxes that ATCO Electric had collected from customers as part of a transition to a flow-through method to compute federal and provincial income taxes.

ATCO Electric's compliance with Direction 38 resulted in the following adjustments being applied to its TFO tariff for the years 2003 through 2007:

- 2007: \$ 2.7 million refund
- 2006: \$ 0.4 million refund
- 2005: \$ 2.5 million refund
- 2004: \$ 0.3 million charge
- 2003: \$10.8 million refund
- Total: \$16.1 million refund

The AESO notes the 2007 refund of \$2.7 million listed above was included in the AESO's 2007 forecast cost for ATCO Electric wires, and therefore does not result in a cost variance for 2007. Amounts for other years are included in this application in the cost variance discussions for those years where appropriate.

### Line 3 ATCO Electric Isolated Generation

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 2007 recorded isolated generation credit was \$5.9 million, which is \$2.0 million (or 26%) less than the 2007 approved forecast credit of \$7.9 million.

On review, the AESO found the 2007 forecast isolated generation credit was based on the 2006 forecast fuel costs for isolated generation approved for ATCO Electric in AUC Decision 2006-024. However, the forecast fuel costs are not necessarily reflective of pool price for the energy used in communities served by isolated generation. The 2007 forecast credit of \$7.9 million was also significantly higher than the 2006 forecast credit of \$3.5 million and 2005 recorded credit of \$5.9 million noted in the AESO's 2007 GTA. The AESO accordingly concludes that the 2007 forecast isolated generation credit was developed on an inappropriate basis and was thus inappropriately high. The 2007 recorded credit of \$5.9 million is based on actual pool price during 2007 and was determined in accordance with the *Isolated Generating Units and Customer Choice Regulation*.

### Line 15 Location Based Credit Standing Offer (LBC SO)

The LBC SO program provides increased system security, whereby the AESO retains dispatch rights to location-specific generation in return for location-based credits made up of fixed and variable payments. The 2007 recorded costs for LBC SO were \$5.8 million, which is \$1.0 million (or 15%) less than the 2007 approved forecast of \$6.8 million. This variance is due to lower volumes in 2007 compared to forecast and to higher market heat rates compared to forecast. The 2007 actual market heat rate (pool price divided by natural gas price) averaged 11.0 GJ/MWh compared to the 2007 forecast of 7.9 GJ/MWh, and higher market heat rates generally result in lower LBC SO costs.

### 3.1.2 Ancillary Services

The recorded ancillary service costs for 2007 totalled \$232.8 million, which is \$48.3 million (or 26%) more than the 2007 approved forecast of \$184.5 million. The primary component of this variance is an increase in active operating reserves costs of \$59.9 million (or 56%)

reflective of a trend to lower discounts, and in some cases premiums, for operating reserves in recent years. This cost increase was offset by reductions in the costs of black start, transmission must run (TMR), and under frequency mitigation services.

5 Detailed explanations of the variances of the 2007 recorded costs from the 2007 approved forecast are provided in the sections that follow.

### **Lines 18 to 27 Operating Reserves**

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

15 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. In Alberta, regulating reserves track variations in the 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  
20 volumes of regulating reserve are specified as a range in MW over which a level of control is required by the AGC system.

25 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.

30 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.

35 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.

Operating reserves are procured through the Alberta Watt Exchange or directly from suppliers through Over-The-Counter transactions.

### **Lines 18 to 21 Active Operating Reserves**

40 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. 2007 recorded costs were \$167.7 million, which is \$59.9 million (or 56%) more than the 2007 approved forecast of \$107.8 million, and comprised the following amounts:

- 45 • For active regulating reserve, the 2007 recorded cost was \$46.7 million, which is \$12.0 million (or 35%) more than the 2007 approved forecast of \$34.7 million.

- For active spinning reserve, the 2007 recorded cost was \$64.9 million, which is \$23.8 million (or 58%) more than the 2007 approved forecast of \$41.1 million.
- For active supplemental reserve, the 2007 recorded cost was \$56.1 million, which is \$24.1 million (or 75%) more than the 2007 approved forecast of \$32.0 million.

The increase in 2007 recorded costs compared to the approved forecast for all active operating reserves was reflective of a trend to lower discounts, and in some cases premiums, for operating reserves in recent years.

Recorded active operating reserves volumes in 2007 were essentially comparable to the 2007 approved forecast.

#### Lines 22 to 25 Standby Operating Reserves

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.

For standby regulating reserves premiums, the 2007 recorded cost was \$5.6 million, which is \$2.3 million (or 70%) more than the 2007 approved forecast of \$3.3 million reflective of a trend to lower discounts, and in some cases premiums, for operating reserves in recent years. The 2007 recorded volumes for premiums were essentially comparable to the 2007 approved forecast.

For standby regulating reserves activations, the 2007 recorded cost was \$0.6 million, which is \$0.7 million (or 54%) less than the 2007 approved forecast of \$1.3 million. This variance is due to 2007 recorded volumes for activations being 73% lower than forecast as a result of higher than forecast unit availability of active regulating reserve providers.

For standby spinning reserves premiums, the 2007 recorded cost was \$4.0 million, which is \$1.3 million (or 48%) more than the 2007 approved forecast of \$2.7 million due to slightly higher volumes arising from the occasional substitution of standby spinning reserves for standby supplemental reserves for cost-saving purposes and to changes in offer price strategies of the providers of operating reserves.

For standby spinning reserves activations, the 2007 recorded costs was \$4.9 million which is \$1.9 million (or 63%) more than the 2007 approved forecast of \$3.0 million, due to higher than forecasted pool prices which resulted in higher activation prices. The higher activation prices were offset by 2007 recorded volumes for activations being 28% lower than forecast as a result of higher than forecast unit availability of active spinning reserve providers.

For standby supplemental reserves premiums, the 2007 recorded cost was \$1.6 million, which is \$0.6 million (or 60%) more than the 2007 approved forecast of \$1.0 million reflective of a trend to lower discounts, and in some cases premiums, for operating reserves in recent years.

5 For standby supplemental reserves activations, the 2007 recorded costs was \$1.2 million, which is \$1.0 million (or 45%) less than the 2007 approved forecast of \$2.2 million due to 2007 recorded volumes for activations being 74% lower than forecast as a result of higher than forecast unit availability of active supplemental reserve providers. The lower activation volumes were offset in part by higher than forecasted pool prices which resulted in higher activation prices.

10 *Line 26 Trading Fees and Other Related Charges*

The 2007 recorded cost for trading fees and other related charges was a credit of \$4.8 million. No corresponding amount was included in the approved forecast. The variance arose from unforecast collections of non-compliance charges of \$5.5 million, offset by trading costs of \$0.7 million.

15 Other variances between recorded and forecast operating reserves costs are not significant, and reflect reasonable variability of recorded costs compared to forecast costs.

20 **Lines 28 to 36 Other Ancillary Services**

Other ancillary services include the remaining services that the AESO procures for the secure and reliable operation of the AIES. These services are normally procured through bilateral contract negotiations with one or more suppliers, and include Brazeau fast ramp, black start, transmission must run (TMR), under frequency mitigation, Poplar Hill, interruptible load remedial action scheme (ILRAS), and generator remedial action schemes (GRAS) services.

25 The 2007 recorded cost of other ancillary services was \$52.1 million, which is \$11.2 million (or 18%) less than the 2007 approved forecast of \$63.3 million, primarily due to prices being lower than forecast for TMR.

30 Black start service is provided by suppliers that have the ability to self-start, energize transmission lines, and provide start up power to other generators. This service is integral to the AESO's system restoration plan and enables timely restoration of electrical supply on the AIES in the unlikely event of a blackout. The 2007 recorded cost for black start service was \$2.0 million, which is \$0.8 million (or 30%) less than the 2007 approved forecast of \$2.8 million due to the AESO being unable to conclude contract negotiations with one black start service provider.

35 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 service is normally procured through commercial agreements negotiated between the AESO and suppliers. TMR agreements provide the AESO with dispatch rights to TMR generation to ensure adequate voltages are maintained following transmission or generation contingencies on the system. The 2007 recorded cost for TMR was \$42.5 million, which is \$8.3 million (or 16%) less than the 2007 approved forecast of \$50.8 million due to higher market heat rates than forecast for 2007. The 2007 actual market heat rate (pool price divided by natural gas price) averaged 11.0 GJ/MWh compared to the 2007 forecast of 7.9 GJ/MWh, and higher market heat rates generally result in lower TMR costs.

5 The 2007 recorded cost for TMR includes costs finalized in 2008 through a commercial agreement with ATCO Power for compensation for TMR service provided by the Rainbow Lake generating units, as confirmed in a letter from the AESO to the AUC dated March 20, 2008, in accordance with a direction in AUC Decision 2008-014 on the AESO's Ancillary Services Article 11 Negotiated Settlement.

10 The agreement included the following increases to compensation for TMR service provided by the Rainbow Lake generating units from January 2006 to February 2008:

- 2008: \$0.009 million
- 2007: \$1.225 million
- 2006: \$0.888 million
- Total: \$2.122 million

15 Under the agreement, no adjustments to compensation would be made for TMR service provided by the Rainbow Lake generating units from December 16, 2004 to December 2005. The AESO notes the 2008 amount listed above will be included in the AESO's 2008 deferral account reconciliation application.

20 The AESO considers that this commercial agreement settles the outstanding issues of TMR compensation with ATCO Power, represents appropriate compensation for TMR service provided by the Rainbow Lake generating units in the past, and provides a reasonable basis for future compensation for TMR service from those units. It is therefore appropriate to include those amounts in the deferral accounts reconciled in this application.

25 Under frequency mitigation 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 2007 recorded cost for under frequency mitigation was \$5.0 million, which is \$1.0 million (or 16%) less than the 2007 approved forecast of \$5.9 million due to contracted MW levels being lowered by one service providers as a result of a change in operations at their facility.

35 Interruptible load remedial action scheme (ILRAS) 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 2007 recorded cost for ILRAS service was \$0.004 million, which is \$0.7 million (or 99%) less than the 2007 approved forecast of \$0.7 million due to the provision of ILRAS being amended in early 2007 such that ILRAS is utilized only when the AIES is experiencing or expects an imminent supply shortfall.

45 Generator remedial action schemes (GRAS) respond to the sudden loss of the Alberta-BC interconnection during high levels of export by requiring generators to trip off instantaneously to stabilize system frequency. At the time of filing its 2007 GTA, the AESO expected to begin contracting for GRAS services in 2007. However, the service was not procured during 2007, resulting in the cost being \$0.5 million (or 100%) less than the 2007

approved forecast of \$0.5 million which had been included as a placeholder estimate in the AESO's 2007 revenue requirement. The AESO currently has no plans to implement GRAS in the near future.

5 The 2007 recorded costs for the remaining other ancillary services (Brazeau fast ramp and Poplar Hill) did not vary significantly from the 2007 approved forecast.

### **3.1.3 Other Industry Costs**

10 The 2007 recorded other industry costs were \$4.8 million, which is \$0.7 million (or 13%) less than the 2007 approved forecast of \$5.5 million, due to both recorded external regulatory costs and WECC costs being less than forecast.

### **Line 38 External Regulatory Costs**

15 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.

20 The 2007 recorded external regulatory costs were \$0.7 million, which is \$0.4 million (32%) less than the 2007 approved forecast of \$1.1 million. In 2007, recorded external regulatory costs represented the recoverable costs of the AESO and registered participants related to the review and variance of the Edmonton-Calgary 500 kV transmission need Decision 2005-031. The 2007 forecast amount had been based on the estimated cost recovery for several AESO proceedings which did not result in cost awards in 2007, including:

- 25 • Southeast Alberta Transmission Development Application, filed on November 5, 2007;
- Ancillary Services Article 11 Amendment, filed as a negotiated settlement on November 26, 2007;
- 2004-2005 Deferral Account Reconciliation Application, filed on December 1, 2007;
- Terms and Conditions Amendment Application, filed on February 27, 2008; and
- 30 • Northeast Alberta Transmission Development Application, which has been separated into a number of projects at different stages of consultation, planning, and application.

### **Line 39 Western Electricity Coordinating Council (WECC) Costs**

35 The AESO is a member of WECC, the body responsible for coordinating and promoting electricity system reliability in the Western North American interconnected electric system. The fee for WECC membership is based on a control area *pro rata* assessment based on net energy for load, which results in the AESO paying the bulk of the Alberta control area charges. The 2007 recorded costs for WECC membership were \$1.8 million, which is \$0.4 million (or 19%) less than the forecast of \$2.2 million due to lower than anticipated WECC costs and a lower US currency exchange rate.

40 The 2007 recorded costs for the AESO's share of AUC overhead did not vary significantly from the 2007 approved forecast.

### **3.1.4 General and Administrative Costs**

45 The 2007 recorded general and administrative costs were \$44.8 million, which is \$3.5 million (9%) higher than the 2007 approved forecast of \$41.3 million. This variance was driven primarily by increases in consultants, legal fees, and telecommunication and IT maintenance

costs, and increases in interest and amortization and depreciation expenses, with smaller increases and decreases in other general and administrative cost components offsetting each other.

5 **Line 43 Consultants**

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 and shortages. The 2007 recorded consulting costs were \$5.9 million, which is \$2.6 million (78%) more than the 2007 approved forecast of \$3.3 million. This variance is due to increases in the following areas during 2007:

- 10 • enhanced public education and outreach arising from new industry responsibilities,
- business continuity planning and operating protocols,
- specialized information technology support and project management,
- 15 • additional assistance to support processing and managing interconnection applications,  
and
- project management and technical expertise for EMS replacement project scoping and vendor selection.

20 **Line 46 Legal**

Corporate legal costs are for non-recoverable regulatory legal costs (in excess of the AUC Scale of Costs guidelines) and for general business matters. The 2007 recorded costs were \$1.1 million, which is \$0.7 million (or 171%) more than the 2007 approved forecast of \$0.4 million. This variance is due to higher than anticipated costs for general business matters and for regulatory proceedings such as the review and variance of the Edmonton-Calgary 500 kV transmission need Decision 2005-031 and the Montana Alberta Tie Ltd. interconnection need application.

30 **Line 51 Telecomm and IT Maintenance**

Telecomm and IT maintenance costs arise primarily from costs related to the network and telephone communications requirements of the AESO and to software licenses to support the operating system and general applications used by the AESO. The 2007 recorded costs were \$2.6 million, which is \$0.5 million (or 24%) more than the 2007 approved forecast of \$2.1 million, primarily due to the cost of the telecommunication links required between the new System Coordination Centre, the AESO offices in downtown Calgary, and the secondary data centre. IT maintenance costs also increased due to requirements for additional software licenses as well as maintenance for a full year on new systems related to the System Coordination Centre.

40 **Line 54 Interest**

Interest expense includes:

- 45 • 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; and
- amounts reflecting the recognition of interest on deferral account balances and its redistribution between production months to allow the appropriate allocation of costs

under the extraordinary circumstances of this deferral account reconciliation application as detailed in section 2.3.

5 The 2007 recorded costs for interest expense were \$1.8 million, which is \$0.6 million (or 53%) more than the 2007 approved forecast of \$1.2 million. The \$1.8 million of recorded interest expense comprises \$1.3 million of interest expense as actually incurred during 2007, plus \$0.5 million reflecting the recognition and redistribution of interest discussed above. The variance between recorded and forecast costs is due primarily to the redistribution of interest to account for the extraordinary circumstances of this application.

10 **Line 55 Amortization and Depreciation**

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

- 15 • three (3) years for office equipment and computer hardware,
- five (5) years for computer software,
- 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.

20 The 2007 recorded amortization and depreciation costs were \$3.9 million, which is \$0.5 million (or 12%) less than the 2007 approved forecast of \$4.4 million, primarily due to the majority of asset purchases being completed in the last few months of the year rather than earlier in the year as forecast.

25 The 2007 recorded costs for the remaining general and administrative components did not vary significantly from the 2007 approved forecast.

30 **3.1.5 Capital**

Capital investment is required by the AESO for the development of IT infrastructure necessary to support the transmission function, for the new System Coordination Centre (SCC) facility and infrastructure, and for leasehold improvements, furniture, and equipment. Although the 2007 recorded capital costs did not vary significantly from the 2007 approved forecast, the AESO provides the following information on capital costs related to the System Coordination Centre.

35 **Line 62 System Coordination Centre**

40 In 2002 the AESO began the process of planning, designing, and constructing a single-tenant, security-focused facility for its System Coordination Centre operations. This project was approved by the AESO Board in June 2004, and was approved by the AUC separately from the AESO's 2005 revenue requirement in Decision 2005-021 dated March 22, 2005. The original project budget of \$15.2 million was updated to \$20.8 million in a cost variance report filed with the AUC on November 22, 2005, primarily reflecting inflation of industry construction costs.

45 The AUC acknowledged the cost increase explained in the variance report, and noted that actual costs will be reviewed for prudence in the deferral account reconciliation process. The

AUC further directed the AESO to report any further cost increases if they exceeded 10% of the updated cost estimate of \$20.8 million set out in the variance report.

The System Coordination Centre facility was substantially completed in December 2006 with occupancy occurring in January 2007. The final total construction cost is estimated to be \$21.2 million, which is \$0.4 million (or 2%) more than the updated cost estimate of \$20.8 million. The final variance is consistent with the detailed variance analysis provided in the cost variance report filed with the AUC on November 22, 2005. The AESO notes that as of March 31, 2008, approximately \$0.1 million of the \$21.2 million total construction costs remains outstanding for the final stage of construction.

The cost of the System Coordination Centre has been allocated 67% to transmission customers, consistent with the cost allocation methodology used for 2006-2008 and described in sections 2.7 and 2.8 of the AESO's 2007 GTA. The allocation is based on the utilization and allocation percentages of the departments occupying the facility. The capital cost allocated to transmission customers for the System Coordination Centre project is therefore \$14.2 million, calculated as 67% of the final cost estimate of \$21.2 million.

### 3.2 2007 Revenue Variances

Table 3-2 presents AESO revenue (excluding revenue related to losses) forecast to be collected from base rates in effect during 2007. The table also includes recorded revenue as collected through 2007 base rates, as well as variances between forecast and recorded revenues in both dollar amounts and as a percentage of forecast revenue. (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.)

The base rates which were in effect during 2007 were approved at the conclusion of the AESO's 2006 GTA proceeding, in Order U2005-464 dated December 20, 2005. Those rates were based on the AESO's 2006 forecast revenue requirement and 2006 forecast billing determinants, and continued in effect through 2007 as rates arising from the AESO 2007

Table 3-2 2007 Base Rate Revenue Variances (Excluding Losses), \$ 000 000

<u>Line No.</u>	<u>Forecast Revenue</u>	<u>Recorded Revenue</u>	<u>Variance Over (Under)</u>		
			<u>\$</u>	<u>%</u>	
	<u>(a)</u>	<u>(b)</u>	<u>(c)=(b)-(a)</u>	<u>(d)=(c)÷(a)</u>	
<u>Demand Transmission Service</u>					
<u>1</u>	<u>Interconnection</u>	<u>\$478.8</u>	<u>\$478.8</u>	<u>\$0.1</u>	<u>0.0%</u>
<u>2</u>	<u>Operating Reserve</u>	<u>145.5</u>	<u>145.9</u>	<u>0.4</u>	<u>0.3%</u>
<u>3</u>	<u>Voltage Control</u>	<u>53.6</u>	<u>52.8</u>	<u>(0.8)</u>	<u>(1.4%)</u>
<u>4</u>	<u>Other System Support</u>	<u>7.7</u>	<u>8.0</u>	<u>0.3</u>	<u>3.9%</u>
<u>5</u>	<u>Total DTS</u>	<u>\$685.6</u>	<u>\$685.6</u>	<u>\$0.0</u>	<u>0.0%</u>

Note: Numbers may not add due to rounding.

GTA were not approved until after year-end. To calculate the 2007 forecast revenue presented in Table 3-2, the AESO applied the rates to its forecast of billing determinants for 2007 as filed in the AESO's 2007 General Tariff Application on November 3, 2006.

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 2007 recorded DTS base rates revenue in column (b) of Table 3-2 totalled \$685.6 million, which is the same as the 2007 forecast revenue of \$685.6 million.

The base rate revenue variances for individual DTS rate components varied from about 1% below forecast up to 4% above forecast, which is considered small enough that specific variance explanations are not required.

### **3.3 2007 Deferral Account Balance**

Costs and revenue variances through the year give rise to deferral account balances. The deferral account balances for 2007 are summarized in Table 3-3, and reflect the 2007 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.

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 the quarter and forecast billing volumes for the quarter.

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

Line No.	Recorded	Recorded	Over	Rider C	Net Over (Under)		
	Base Rate		(Under)	Collected	Collection Variance		
	Revenue	Costs	Collection	(Refunded)	\$	%	
	(a)	(b)	(c)=(a)+(b)	(d)	(e)=(c)+(d)	(f)=- (e)÷(b)	
<b><u>Demand Transmission Service</u></b>							
1	Interconnection	478.8	(509.0)	(30.2)	34.1	3.9	0.8%
2	Operating Reserve	145.9	(183.3)	(37.4)	36.8	(0.6)	(0.3%)
3	Voltage Control	52.8	(42.5)	10.3	(11.6)	(1.3)	(3.0%)
4	Other System Support	8.0	(6.9)	1.1	(1.2)	(0.1)	(1.2%)
5	<b>Total DTS</b>	<b>685.6</b>	<b>(741.7)</b>	<b>(56.1)</b>	<b>58.1</b>	<b>2.0</b>	<b>0.3%</b>

Note: Numbers may not add due to rounding.



5

The total recorded revenue collected with respect to 2007 is therefore the sum of revenue collected through base rates as discussed in section 3.2, plus revenue collected or refunded through Rider C during 2007 and in the first quarter of 2008. The goal of Rider C is to provide total revenue which aligns more closely with total costs incurred than would be possible through the use of base rates only.

10

In general, Rider C collections and refunds for 2007 maintained net deferral account balances at reasonable levels of less than  $\pm 3\%$  of costs for all rate components.

Additional details on 2007 recorded revenues and costs 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.

## 4 2006 FINANCIAL RESULTS AND DEFERRAL ACCOUNT BALANCE

5 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, AR 86/2007*. Therefore, the financial results and deferral account balance for 2006 discussed in this section do not include costs and revenues related to losses.

10 In determining the financial results and deferral account balance for 2006, all other revenue and cost transactions that occurred from January 1, 2006, to March 31, 2008 and that relate to 2006 have been included in the reconciliations. These transactions establish the 2006 production month data for deferral account reconciliation purposes in this application. The net result of these transactions is \$704.3 million in costs and \$715.7 million in customer revenues (including Rider C collections and refunds) being attributed to 2006.

15 The AESO notes that revenue and cost transactions that occurred from January 1, 2006, to March 31, 2008 may also relate, in whole or in part, to years prior to 2006. 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. Where the transaction (or part of the transaction) relates to losses prior to 2006, it also has been assigned to the prior year. Detail on the assignment between 2006 and prior years for transactions which occurred in 2006, 2007, and 2008 is provided in Appendix E-1 of this application.

### 4.1 2006 Cost Variances

25 Table 4-1 presents the AESO's 2006 revenue requirement (excluding losses):

- 30 • as approved in AUC Order 2005-464 on the AESO's 2005-2006 General Tariff Application Second Refiling, dated December 20, 2005, and
- incorporating the 2006 Own Costs Update filed with the AUC on January 13, 2006.

35 Information on the AESO's 2006 revenue requirement is contained in

- Decision 2005-131 on the AESO's 2005-2006 General Tariff Application Refiling, dated December 6, 2005, and
- Decision 2005-096 on the AESO's 2007 General Tariff Application, dated August 28, 2005.

40 Additional information is also provided in the AESO's 2006 General Tariff Application itself available on the AESO web site at [www.aeso.ca](http://www.aeso.ca) by following the path Tariff ► Previous Applications ► 2006 Tariff Application (Application 1363012).

45 The AUC noted in Decision 2005-096 that the AESO's "own costs" included in the 2006 GTA were a placeholder to be updated as a result of a consultative process with stakeholders. The AESO's 2006 budget was reviewed through the Budget Review Committee (comprising members of the AESO's stakeholder community) and approved by the AESO's Board Members in late 2005. The 2006 Own Costs Update totalled \$0.7 million

**Table 4-1 2006 Revenue Requirement and Recorded Costs (Excluding Losses), \$ 000 000**

Line No.		Approved	Recorded	Variance Over (Under)	
		Forecast	Costs	\$	%
		(a)	(b)	(c)=(b)-(a)	(d)=(c)÷(a)
<b>WIRES</b>					
<b>TFO Wires-Related Costs</b>					
1	AltaLink	193.7	189.0	(4.7)	(2.4%)
2	ATCO Electric Ltd.	161.2	166.1	4.9	3.1%
3	Isolated Generation	(3.5)	(7.0)	(3.5)	100.1%
4	Subtotal ATCO Costs	157.7	159.2	1.4	0.9%
5	Enmax Power Corporation	33.6	31.9	(1.7)	(5.2%)
6	EPCOR Transmission Inc.	32.8	36.9	4.1	12.3%
7	City of Lethbridge	4.5	4.2	(0.3)	(5.9%)
8	TransAlta	3.7	3.7	(0.0)	(1.0%)
9	Refund to the AESO	-	-	-	-
10	Subtotal TransAlta Costs	3.7	3.7	(0.0)	(1.0%)
11	City of Red Deer	1.8	1.8	(0.0)	(0.4%)
12	FortisAlberta Networks (Farm)	1.9	1.5	(0.4)	(21.1%)
13	Subtotal TFO Wires-Related Costs	429.8	428.1	(1.7)	(0.4%)
<b>Non-Wires Costs</b>					
14	Invitation to Bid on Credits (IBOC)	2.0	1.7	(0.3)	(15.2%)
15	Location Based Credit Standing Offer (LBC SO)	7.7	4.5	(3.2)	(41.8%)
16	Subtotal IBOC/LBC SO Costs	9.7	6.2	(3.5)	(36.3%)
17	TOTAL WIRES COSTS	439.5	434.3	(5.2)	(1.2%)
<b>ANCILLARY SERVICES</b>					
<b>Operating Reserves</b>					
Active					
18	Regulating	24.8	47.1	22.3	89.6%
19	Spinning	25.6	63.4	37.8	147.4%
20	Supplemental	20.9	61.5	40.6	194.5%
21	Subtotal Active Reserves	71.4	172.0	100.7	141.0%
Standby					
22	Regulating	7.6	5.2	(2.4)	(31.4%)
23	Spinning	4.3	6.2	1.9	42.8%
24	Supplemental	2.1	2.5	0.4	20.9%
25	Subtotal Standby Reserves	14.0	13.9	(0.1)	(0.7%)
26	Trading Fees & Other Related Charges	-	(2.9)	(2.9)	-
27	Subtotal Operating Reserves	85.3	183.0	97.6	114.4%
<b>Other Ancillary Services</b>					
28	Generator Remedial Action Schemes (RAS)	0.4	0.5	0.1	22.8%
29	Black Start	2.3	1.8	(0.4)	(18.7%)
30	Transmission Must Run (TMR)	53.2	39.3	(13.9)	(26.1%)
31	Under Frequency Mitigation	6.9	5.6	(1.3)	(18.7%)
32	Subtotal Other Ancillary Services	62.8	47.3	(15.5)	(24.7%)

*Table 4-1 2006 Revenue Requirement and Recorded Costs (Excluding Losses), \$ 000 000 (cont'd)*

<u>Line No.</u>		<u>Approved</u>	<u>Recorded</u>	<u>Variance Over (Under)</u>	
		<u>Forecast</u>	<u>Costs</u>	<u>\$</u>	<u>%</u>
		<u>(a)</u>	<u>(b)</u>	<u>(c)=(b)-(a)</u>	<u>(d)=(c)÷(a)</u>
<b><u>Poplar Hill/ILRAS</u></b>					
33	Poplar Hill	1.9	2.0	0.1	5.1%
34	Interruptible Load Remedial Action Scheme (ILRAS)	0.5	0.8	0.3	53.1%
35	<b>Subtotal Poplar Hill/ILRAS</b>	<b>2.4</b>	<b>2.8</b>	<b>0.4</b>	<b>15.9%</b>
36	<b>TOTAL ANCILLARY SERVICES</b>	<b>150.6</b>	<b>233.0</b>	<b>82.5</b>	<b>54.8%</b>
<b><u>OTHER INDUSTRY COSTS</u></b>					
37	External Regulatory Costs	2.3	0.3	(2.0)	(86.3%)
38	Western Electricity Coordination Council (WECC)	1.4	1.3	(0.1)	(6.8%)
39	Share of AUC Overhead	1.8	2.0	0.2	9.2%
40	Balancing Pool	-	-	-	-
41	<b>TOTAL OTHER INDUSTRY COSTS</b>	<b>5.5</b>	<b>3.6</b>	<b>(1.9)</b>	<b>(34.8%)</b>
<b><u>GENERAL AND ADMINISTRATIVE COSTS</u></b>					
<b><u>Administrative Costs</u></b>					
42	Staff and Benefits	20.8	20.1	(0.7)	(3.5%)
43	Staff and Benefits Allocated to Capital	(0.9)	(0.7)	0.2	(23.0%)
44	<b>Subtotal Staff and Benefits</b>	<b>19.9</b>	<b>19.4</b>	<b>(0.5)</b>	<b>(2.6%)</b>
45	Consultants	2.1	2.9	0.8	39.3%
46	Board Members Fees	0.4	0.4	(0.0)	(11.5%)
47	Travel and Training	1.0	0.8	(0.2)	(16.4%)
48	Legal	0.4	0.4	0.0	3.8%
49	Accounting and Tax Advice	0.2	0.2	0.0	12.5%
50	Rent <sup>1</sup>	1.5	1.4	(0.1)	(5.7%)
51	Insurance	0.4	0.4	(0.0)	(6.3%)
52	Other Administrative Costs	1.3	1.5	0.2	17.4%
53	Telecomm and IT Maintenance	1.6	1.5	(0.1)	(4.6%)
54	System Access Application Fees	-	(0.5)	(0.5)	-
55	<b>Total Administrative Costs</b>	<b>28.8</b>	<b>28.5</b>	<b>(0.3)</b>	<b>(1.1%)</b>
<b><u>General Costs</u></b>					
56	Interest	0.5	1.9	1.4	278.8%
57	Amortization and Depreciation	2.9	3.0	0.1	4.8%
58	Taxes	-	-	-	-
59	<b>Total General Costs</b>	<b>3.4</b>	<b>4.9</b>	<b>1.5</b>	<b>45.1%</b>
60	<b>TOTAL GENERAL &amp; ADMINISTRATIVE COSTS</b>	<b>32.2</b>	<b>33.4</b>	<b>1.2</b>	<b>3.8%</b>
61	<b>Total G&amp;A and Other Industry Costs</b>	<b>37.7</b>	<b>37.0</b>	<b>(0.7)</b>	<b>(1.9%)</b>
62	<b>TOTAL REVENUE REQUIREMENT</b>	<b>627.7</b>	<b>704.3</b>	<b>76.6</b>	<b>12.2%</b>

Table 4-1 2006 Revenue Requirement and Recorded Costs (Excluding Losses), \$ 000 000 (cont'd)

<u>Line No.</u>		<u>Approved</u>	<u>Recorded</u>	<u>Variance Over (Under)</u>	
		<u>Forecast</u>	<u>Costs</u>	<u>\$</u>	<u>%</u>
		<u>(a)</u>	<u>(b)</u>	<u>(c)=(b)-(a)</u>	<u>(d)=(c)÷(a)</u>
<u>CAPITAL</u>					
63	Salaries and Benefits	0.9	0.7	(0.2)	(23.0%)
64	Other Capital	2.7	2.9	0.2	7.4%
65	System Coordination Centre	11.6	11.9	0.3	2.6%
66	<u>Total Capital</u>	<u>15.2</u>	<u>15.5</u>	<u>0.3</u>	<u>1.9%</u>

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 2006 Recorded Costs on Line 50

5 more than the placeholder amounts filed in the 2006 GTA, and comprehensive explanations of variances from the placeholder amounts were provided in the Update. The Update amounts have therefore been incorporated in the approved forecast of the AESO's 2006 revenue requirement. As noted in the AESO's 2007 GTA, the allocation of capital costs of the AESO's new System Coordination Centre (as discussed in section 3.1.6 of this application) was inadvertently omitted from the AESO's 2006 Own Costs Update, but has  
10 been appropriately included in Table 4-1.

15 Table 4-1 also includes recorded costs as incurred for 2006, and variances between approved and recorded costs in both dollar amounts and as a percentage of approved costs.

Total 2006 recorded costs are \$76.6 million (12%) higher than the total 2006 approved revenue requirement. This variance consists of 2006 recorded costs being:

- \$5.2 million (1%) lower than the 2006 approved revenue requirement for wires,
- \$82.5 million (55%) higher for ancillary services,
- \$1.9 million (35%) lower for other industry costs, and
- \$1.2 million (4%) higher for general and administrative costs.

25 Variances arise due to a number of factors, including finalization of TFO costs through AUC 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 ±\$3.0 million, which represents approximately 10% of the \$32.2 million general and administrative costs component of the AESO's revenue requirement. A line item variance smaller than ±\$3.0 million is also considered significant when it is both at least ±\$0.3 million and at least  
30 ±10% of the approved line item amount. The ±\$0.3 million threshold represents approximately 1% of the \$32.2 million general and administrative costs component of the AESO's revenue requirement, while the AESO considers ±10% to be a reasonable threshold below which specific variance explanations are not required.

5 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 ±\$0.3 million or less than ±10% (except where such variance is ±\$3.0 million or greater) explanations are not provided, as such variances are small enough that specific variance explanations are not required.

#### 4.1.1 Wires Costs

10 The AESO's 2006 TFO wires costs forecast was based on TFO costs approved at the time of the AESO's 2006 General Tariff Application Second Refiling on December 9, 2005. These costs were comprehensively summarized in section 2.2 of the AESO's 2006 General Tariff Application filed on January 31, 2005, and updated in response to Direction 4B in the AESO's 2005-2006 GTA Refiling on September 27, 2005.

15 The recorded 2006 wires costs were as billed by the TFOs to the AESO based on final 2006 tariffs approved for the TFOs.

#### Line 1 AltaLink

20 The 2006 recorded cost for AltaLink wires was \$189.0 million, which is \$4.7 million (or 2%) less than the 2006 approved forecast of \$193.7 million. The forecast cost was from AUC Decision 2005-082 which approved AltaLink's 2004-2006 Transmission Tariff on a final basis. The recorded cost includes:

- a reduction of \$2.2 million approved in AUC Order U2006-043 to reflect the generic return on equity of 8.93% for 2006 that was approved by the AUC in Order U2005-410, and
- a reduction of \$2.5 million approved on an interim basis in AUC Decision 2007-050 to reflect the reduction during 2006 of the balance of AltaLink's 2005-2006 Debt Cost Deferral Account.

#### Line 2 ATCO Electric

30 The 2006 recorded cost for ATCO Electric wires was \$166.1 million, which is \$4.9 million (or 3%) more than the 2006 approved forecast of \$161.2 million. The forecast cost was from AUC Decision 2005-102 which approved ATCO Electric's 2005 Interim Transmission Facility Owner Tariff on an interim refundable basis. The recorded cost was based on:

- AUC Decision 2006-070 on ATCO Electric's 2005-2006 GTA Refiling which approved transmission tariff revenue of \$171.2 million for 2006,
- AUC Decision 2007-104 on ATCO Electric's 2007-2008 General Tariff Application Refiling which approved a refund of future income taxes that ATCO Electric had collected from customers, of which \$0.4 million was applied as a refund to 2006 as discussed in section 3.1.1 of this application, and
- AUC Order U2007-256 on ATCO Electric's 2006 Transmission Deferral Accounts which approved a one-time refund of \$4.6 million to the AESO with respect to 2006.

#### Line 3 ATCO Electric Isolated Generation

45 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 2006 recorded isolated generation credit was \$7.0 million, which is \$3.5 million (or 100%)

more than the 2006 approved forecast credit of \$3.5 million. The 2006 forecast credit was estimated in the AESO's 2006 tariff application based on an average pool price of \$41.20/MWh. The 2006 recorded credit is based on actual pool price, which averaged \$80.79/MWh or 96% higher than forecast.

**Line 6 EPCOR Transmission Inc.**

The 2006 recorded cost for EPCOR wires was \$36.9 million, which is \$4.1 million (or 12%) more than the 2006 approved forecast of \$32.8 million. The forecast cost was from AUC Order U2004-418 which approved EPCOR Transmission's Interim 2005 Transmission Tariff on an interim refundable basis. The recorded cost was from AUC Order U2006-240 which approved EPCOR Transmission's 2005-2006 Transmission Facility Owner Tariff Refiling on a final basis.

**Line 12 FortisAlberta Networks (Farm)**

"Farm transmission costs" are costs determined by the owner of an electric distribution system in accordance with the *Electric Utilities Act*, S.A. 2003, c. E-5.1, and paid by the AESO. The 2006 recorded cost for FortisAlberta Networks farm transmission wires was \$1.5 million, which is \$0.4 million (or 21%) less than the 2006 approved forecast of \$1.9 million. The forecast cost was the 2003 amount approved in AUC Decision 2003-019 on FortisAlberta's 2002/2003 Distribution Tariff. The recorded cost was the 2006 amount approved in AUC Decision 2006-099 on FortisAlberta's 2006/2007 Distribution Tariff — Phase II and Other Matters.

Other variances between recorded and forecast wires costs are not significant, and reflect costs paid in accordance with decisions and approvals subsequent to the AESO's 2006 General Tariff Application proceeding.

**Line 14 Invitation to Bid on Credits (IBOC)**

The IBOC program provides a financial credit to a specific generator in the Calgary area based on the volume of megawatt-hours generated each month. The 2006 recorded cost for IBOC was \$1.7 million, which is \$0.3 million (or 15%) less than the 2006 approved forecast of \$2.0 million due to IBOC volumes for 2006 being lower than expected.

**Line 15 Location Based Credit Standing Offer (LBC SO)**

The LBC SO program provides increased system security, whereby the AESO retains dispatch rights to location-specific generation in return for location-based credits made up of fixed and variable payments. The 2006 recorded costs for LBC SO were \$4.5 million, which is \$3.2 million (or 42%) less than the 2006 approved forecast of \$7.7 million. This variance is due to lower volumes and higher market heat rates in 2006 as compared to the forecast, and to low availability in 2006 for one of the three LBC SO facilities which reduced the fixed payments to that facility for most of the year. The 2006 actual market heat rate (pool price divided by natural gas price) averaged 13.1 GJ/MWh compared to the 2006 forecast of 7.1 GJ/MWh, and higher market heat rates generally result in lower LBC SO costs.

**4.1.2 Ancillary Services**

The recorded ancillary service costs for 2006 totalled \$233.0 million, which is \$82.5 million (or 55%) more than the 2006 approved forecast of \$150.6 million. The primary component of

5 this variance is an increase in active operating reserves costs of \$100.7 million (or 141%) due to higher than forecasted pool prices and changes in offer price strategies of the providers of operating reserves. This cost increase was offset by a reduction in the cost of transmission must run (TMR) service.

Detailed explanations of the variances of the 2006 recorded costs from the 2006 approved forecast are provided in the sections that follow.

10 **Lines 18 to 27 Operating Reserves**

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

15 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. In Alberta, regulating reserves track variations in the 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 MW over which a level of control is required by the AGC system.

20 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.

25 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.

30 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.

35 Operating reserves are procured through the Alberta Watt Exchange or directly from suppliers through Over-The-Counter transactions.

40 **Lines 18 to 21 Active Operating Reserves**

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. 2006 recorded costs were \$172.0 million, which is \$100.7 million (or 141%) more than the 2006 approved forecast of \$71.4 million, and comprised the following amounts:

- 45
  - For active regulating reserve, the 2006 recorded cost was \$47.1 million, which is \$22.3 million (or 90%) more than the 2006 approved forecast of \$24.8 million.

- For active spinning reserve, the 2006 recorded cost was \$63.4 million, which is \$37.8 million (or 147%) more than the 2006 approved forecast of \$25.6 million.
- For active supplemental reserve, the 2006 recorded cost was \$61.5 million, which is \$40.6 million (or 194%) more than the 2006 approved forecast of \$20.9 million.

The increase in 2007 recorded costs compared to the approved forecast was due to higher than forecasted pool prices and changes in offer price strategies of the providers of operating reserves. The 2006 recorded average pool price was \$80.79/MWh, which is \$39.59/MWh (or 96%) higher than the forecast average pool price of \$41.20/MWh.

Recorded active operating reserves volumes in 2006 were essentially comparable to the 2006 approved forecast.

#### *Lines 22 to 25 Standby Operating Reserves*

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.

For standby regulating reserves premiums, the 2006 recorded cost was \$4.2 million, which is \$2.0 million (or 90%) more than the 2006 approved forecast of \$2.2 million due to a higher than forecast pool price which resulted in a higher premium from the market. The 2006 recorded volumes for premiums are essentially comparable to the forecast.

For standby regulating reserves activations, the 2006 recorded cost was \$1.0 million, which is \$4.4 million (or 81%) less than the 2006 approved forecast of \$5.4 million. This variance is due to 2006 recorded volumes for activations being 87% lower than forecast as a result of higher than forecast unit availability of active regulating reserve providers.

For standby spinning reserves premiums, the 2006 recorded cost was \$3.3 million, which is \$1.4 million (or 74%) more than the 2006 approved forecast of \$1.9 million, due in part to slightly higher volumes arising from the occasional substitution of standby spinning reserves for standby supplemental reserves for cost-saving purposes and in part to a higher than forecast pool price which resulted in a slightly higher premium from the market. The 2006 recorded volumes for standby spinning reserves premiums were essentially comparable to the forecast.

For standby spinning reserves activations, the 2006 recorded costs was \$2.9 million, which is \$0.4 million (or 17%) more than the 2006 approved forecast of \$2.4 million due to higher than forecast pool price which resulted in a higher activation price from the market. As an offset to higher activation prices, 2006 recorded volumes for activations were 38% lower than forecast as a result of higher than forecast unit availability of active spinning reserve providers.

For standby supplemental reserves premiums, the 2006 recorded cost was \$1.3 million, which is \$0.5 million (or 63%) more than the 2006 approved forecast of \$0.8 million due to higher than forecast pool price which resulted in a higher premium from the market.

5 Recorded costs for standby supplemental reserves activations in 2006 were essentially comparable to the 2006 approved forecast.

*Line 26 Trading Fees and Other Related Charges*

10 The 2006 recorded cost for trading fees and other related charges was a credit of \$2.9 million. No corresponding amount was included in the approved forecast. The variance arose from unforecast collections of non-compliance charges of \$3.5 million, offset by trading costs of \$0.6 million.

15 Other variances between recorded and forecast operating reserves costs are not significant, and reflect reasonable variability of recorded costs compared to forecast costs.

**Lines 28 to 36 Other Ancillary Services**

20 Other ancillary services include the remaining services that the AESO procures for the secure and reliable operation of the AIES. These services are normally procured through bilateral contract negotiations with one or more suppliers, and include generator remedial action schemes (GRAS), black start, transmission must run (TMR), under frequency mitigation, Poplar Hill, and interruptible load remedial action scheme (ILRAS) services.

25 The 2006 recorded cost of other ancillary services was \$50.1 million, which is \$15.1 million (or 23%) less than the 2006 approved forecast of \$65.2 million, primarily due to prices being lower than forecast for TMR.

30 Black start service is provided by suppliers that have the ability to self-start, energize transmission lines, and provide start up power to other generators. This service is integral to the AESO's system restoration plan and enables timely restoration of electrical supply on the AIES in the unlikely event of a blackout. The 2006 recorded cost for black start service was \$1.8 million, which is \$0.4 million (or 19%) less than the 2006 approved forecast of \$2.3 million due to the AESO being unable to conclude contract negotiations with one black start service provider.

35 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 service is normally procured through commercial agreements negotiated between the AESO and suppliers. TMR agreements provide the AESO with dispatch rights to TMR generation to ensure adequate voltages are maintained following transmission or generation contingencies on the system. The 2006 recorded cost for TMR was \$39.3 million, which is \$13.9 million (or 26%) less than the 2006 approved forecast of \$53.2 million due to higher market heat rates than forecast for 2006. The 2006 actual market heat rate (pool price divided by natural gas price) averaged 13.1 GJ/MWh compared to the 2006 forecast of 7.1 GJ/MWh, and higher market heat rates generally result in lower TMR costs.

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5 The 2006 recorded cost for TMR includes \$0.9 million for costs finalized in 2008 through a commercial agreement with ATCO Power for compensation for TMR service provided by the Rainbow Lake generating units, as discussed for Other Ancillary Services (Lines 28 to 36) in section 3.1.2 of this application.

10 Under frequency mitigation is configured to automatically trip a specified 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 2006 recorded cost for under frequency mitigation was \$5.6 million, which is \$1.3 million (or 19%) less than the 2006 approved forecast of \$6.9 million due to the AESO securing contracts by way of a competitive procurement process conducted in 2005.

15 Interruptible load remedial action scheme (ILRAS) 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 recorded cost for ILRAS was \$0.8 million, which is \$0.3 million (or 53%) more than the 2006 approved forecast of \$0.5 million due to higher levels of imports than forecasted resulting in more ILRAS being required.

20 The 2006 recorded costs for the remaining other ancillary services (generator remedial action schemes and Poplar Hill) did not vary significantly from the 2006 approved forecast.

#### 25 **4.1.3 Other Industry Costs**

30 The 2006 recorded other industry costs were \$3.6 million, which is \$1.9 million (or 35%) less than the 2006 approved forecast of \$5.5 million, primarily due to recorded external regulatory costs being less than forecast.

#### 35 **Line 41 External Regulatory Costs**

40 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.

45 The 2006 recorded external regulatory costs were \$0.3 million, which is \$2.0 million (86%) less than the 2006 approved forecast of \$2.3 million. In 2006, recorded external regulatory costs represented the recoverable costs of the AESO and registered participants related to the interim approval of Article 11 of the AESO's terms and conditions regarding maximum TMR compensation, and to the 2005-2006 General Tariff Application Refiling. The 2006 forecast amount had been based on the estimated cost recovery for several AESO proceedings which did not result in cost awards in 2006, including:

- 2007 General Tariff Application, filed on November 3, 2006;
- Export, Import, and Merchant Tariffs, included in the 2007 GTA rather than filed separately;

- Generic Transmission Facility Owner Terms and Conditions of Service, which resulted in TFOs leading an initiative concluding with an application filed by AltaLink on September 28, 2007.
- Ancillary Services Article 11 Amendment, filed as a negotiated settlement on November 26, 2007; and
- 2004 Deferral Account Reconciliation Application, filed as part of the 2004-2005 application on December 1, 2007.

#### **4.1.4 General and Administrative Costs**

The 2006 recorded general and administrative costs were \$33.4 million, which is \$1.2 million (or 4%) more than the 2006 approved forecast of \$32.2 million. This variance was driven primarily by increases in consultants and interest expense, offset in part by a decrease in staff and benefits and an increase in system access application fees, with smaller increases and decreases in other general and administrative costs offsetting each other.

#### **Line 45 Consultants**

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 and shortages. The 2006 recorded consulting costs were \$2.9 million, which is \$0.8 million (39%) more than the 2006 approved forecast of \$2.1 million. This variance is due to increases in the following areas during 2006:

- development and preparation of the 2007-2016 10-Year Transmission System Plan,
- additional assistance to support processing and managing interconnection applications,
- specialized information technology support and project management,
- assessment of the existing energy management system (EMS) to develop system specifications which were used for the subsequent request for information (RFI), and
- project management and technical support related the Montana Alberta Tie Ltd. interconnection.

#### **Line 54 System Access Application Fees (Offset)**

Application fees are collected by the AESO in accordance with Article 5 of the terms and conditions of the AESO's 2006 tariff, from customers submitting applications for new or expanded system access service. The 2006 recorded revenue offset from application fees was \$0.5 million, which is \$0.5 million (or 100%) more than the 2006 approved forecast of \$0.0 million.

As part of an interconnection process redesign, the AESO applied and received approval in its 2006 GTA for application fees to be refundable upon energization of the customer's facilities, effective January 1, 2006. The application fees were also simplified and reduced, and due to uncertainty on the amount of fees that would be collected as a revenue offset, the 2006 forecast under the redesigned interconnection process was set to zero. Any fees that were collected and not refunded due to projects being cancelled would be addressed in a deferral account reconciliation application. The net amount of application fee collections and refunds during 2006 resulted in the recorded revenue offset of \$0.5 million.

**Line 57 Interest**

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; and
- amounts reflecting the recognition of interest on deferral account balances and its redistribution between production months to allow the appropriate allocation of costs under the extraordinary circumstances of this deferral account reconciliation application as detailed in section 2.3.

The 2006 recorded costs for interest expense were \$1.9 million, which is \$1.4 million (or 279%) more than the 2006 approved forecast of \$0.5 million. The \$1.9 million of recorded interest expense comprises \$0.1 million credit for interest expense as actually incurred during 2006, plus \$2.0 million reflecting the recognition and redistribution of interest discussed above. The variance between recorded and forecast costs is due primarily to the redistribution of interest to account for the extraordinary circumstances of this application.

The 2006 recorded costs for the remaining general and administrative components did not vary significantly from the 2006 approved forecast.

**4.1.5 Capital**

Capital investment is required by the AESO for the development of IT infrastructure necessary to support the transmission function, for the new System Coordination Centre (SCC) facility and infrastructure, and for leasehold improvements, furniture, and equipment. Although the 2006 recorded capital costs did not vary significantly from the 2006 approved forecast, the AESO provides the following information on capital costs related to the System Coordination Centre.

**Line 65 System Coordination Centre**

The AUC approved the AESO's System Coordination Centre project in Decision 2005-021 dated March 22, 2005. The original project budget of \$15.2 million was updated to \$20.8 million in a cost variance report filed with the AUC on November 22, 2005, in response to which the AUC noted that actual costs will be reviewed for prudence in the deferral account reconciliation process. As discussed in section 3.1.5 of this application, the final total construction cost is estimated to be \$21.2 million.

The recorded costs of the System Coordination Centre project at the end of 2006 were \$17.3 million, of which \$11.9 million (or 67%) was allocated to transmission customers. The 2006 allocated recorded cost of \$11.9 million is \$0.3 million (or 3%) more than the 2006 approved forecast of \$11.6 million.

**4.2 2006 Revenue Variances**

Table 4-2 presents AESO revenue (excluding revenue related to losses) forecast to be collected from base rates in effect during 2006. The table also includes recorded revenue as collected through 2006 base rates, as well as variances between forecast and recorded revenues in both dollar amounts and as a percentage of forecast revenue. (Base rates

Table 4-2 2006 Base Rate Revenue Variances (Excluding Losses), \$ 000 000

<u>Line No.</u>	<u>Forecast Revenue</u>	<u>Recorded Revenue</u>	<u>Variance Over (Under)</u>		
			<u>\$</u>	<u>%</u>	
	<u>(a)</u>	<u>(b)</u>	<u>(c)=(b)-(a)</u>	<u>(d)=(c)÷(a)</u>	
<u>Demand Transmission Service</u>					
1	<u>Interconnection</u>	<u>\$478.8</u>	<u>\$467.0</u>	<u>(\$11.8)</u>	<u>(2.5%)</u>
2	<u>Operating Reserve</u>	<u>88.1</u>	<u>173.4</u>	<u>85.3</u>	<u>96.9%</u>
3	<u>Voltage Control</u>	<u>53.2</u>	<u>52.3</u>	<u>(0.9)</u>	<u>(1.8%)</u>
4	<u>Other System Support</u>	<u>8.7</u>	<u>7.9</u>	<u>(0.8)</u>	<u>(9.0%)</u>
5	<u>Total DTS</u>	<u>\$628.8</u>	<u>\$700.6</u>	<u>\$71.8</u>	<u>11.4%</u>

Note: Numbers may not add due to rounding.

5 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.)

10 The AUC approved the base rates in effect during 2006 in Order U2005-464 dated December 20, 2005. Those rates were based on the AESO's 2006 revenue requirement and billing determinants, with 2006 forecast revenue provided in Schedule 5.9 of the AESO's 2005-2006 GTA Second Refiling dated December 9, 2005.

15 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 2006 recorded DTS base rates revenue in column (b) of Table 4-2 totalled \$700.6 million, which is \$71.8 million (or 11%) more than the 2006 forecast revenue of \$628.8 million.

20 This base rates revenue variance arises mainly from recorded operating reserve revenue of \$173.4 million, which is \$85.3 million (or 97%) more than the 2006 forecast revenue of \$88.1 million. Operating reserve charges in the AESO's 2006 tariff were determined as a percentage of pool price, and recorded pool price during 2006 averaged \$80.79/MWh — about 96% higher than the forecast pool price of \$41.20 in the AESO's 2006 General Tariff Application.

30 Also, the 2006 recorded revenue for other system support services was \$7.9 million, which is \$0.8 million (or 9%) less than the 2006 forecast revenue of \$8.7 million. The 2006 forecast revenue for other system support services was inadvertently based on forecast billing capacity, whereas the recorded revenue was correctly charged on highest metered demand in accordance with the DTS rate. Recorded billing determinants for highest metered demand were about 13% less than those for billing capacity in 2006.

35 The base rate revenue variances for other DTS rate components were 2-3% below forecast, which is considered small enough that specific variance explanations are not required.

### 4.3 2006 Deferral Account Balance

Costs and revenue variances through the year give rise to deferral account balances. The deferral account balances for 2006 are summarized in Table 4-3, and reflect the 2006 recorded costs and revenue provided in Tables 4-1 and 4-2 respectively. Table 4-3 also includes Deferral Account Adjustment Rider C, which collects or refunds revenue to align actual revenues with actual costs by rate and rate component.

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 the quarter and forecast billing volumes for the quarter.

The total recorded revenue collected with respect to 2006 is therefore the sum of revenue collected through base rates as discussed in section 4.2, plus revenue collected or refunded through Rider C during 2006 and in the first quarter of 2007. The goal of Rider C is to provide total revenue which aligns more closely with total costs incurred than would be possible through the use of base rates only.

In general, Rider C collections and refunds for 2006 maintained net deferral account balances at reasonable levels of less than  $\pm 2\%$  of costs for all rate components except other system support services charges, which were overcollected by 15% of costs. However, at only 0.9% of the AESO's annual DTS revenue requirement, other system support services costs represent the smallest AESO rate component. In absolute terms the associated variance represented only a \$1.0 million overcollection over the year.

The AESO also notes that Rider C collections and refunds for 2006 have resulted in a \$10.4 million overcollection of interconnection costs, compared to a \$4.1 million undercollection

Table 4-3 2006 Deferral Account Summary (Excluding Losses), \$ 000 000

Line No.	Recorded	Recorded	Over	Rider C	Net Over (Under)		
	Base Rate		(Under)	Collected	Collection Variance		
	Revenue	Costs	Collection	(Refunded)	\$	%	
	(a)	(b)	(c)=(a)+(b)	(d)	(e)=(c)+(d)	(f)=- (e)÷(b)	
<u>Demand Transmission Service</u>							
1	Interconnection	467.0	(471.1)	(4.1)	14.5	10.4	2.2%
2	Operating Reserve	173.4	(187.3)	(13.8)	13.3	(0.6)	(0.3%)
3	Voltage Control	52.3	(39.3)	12.9	(12.4)	0.5	1.4%
4	Other System Support	7.9	(6.7)	1.3	(0.3)	1.0	14.6%
5	<u>Total DTS</u>	<u>700.6</u>	<u>(704.3)</u>	<u>(3.7)</u>	<u>15.1</u>	<u>11.3</u>	<u>1.6%</u>

Note: Numbers may not add due to rounding.



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before application of Rider C. Rider C during 2006 and the first quarter of 2007 was based on wires costs known or forecast in that period. As discussed in section 4.1.1 of this application, 2006 recorded costs for wires were reduced by AUC decisions issued after 2006, by \$2.5 million for AltaLink and \$5.0 million for ATCO Electric. These reductions significantly increased the overcollection through Rider C, beyond that which would have resulted based on wires costs known or forecast up to the first quarter of 2007.

10

Additional details on 2006 recorded revenues and costs 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.

## **35 2005 FINANCIAL RESULTS AND DEFERRAL ACCOUNT BALANCE**

In determining the financial results and deferral account balance for 2005, all revenue and cost transactions that occurred from January 1, 2005, to ~~July~~March 31, ~~2007~~2008 and that relate to 2005 have been included in the reconciliations. These transactions establish the 2005 production month data for deferral account reconciliation purposes in this application. The net result of these transactions is ~~\$857.2851.4~~ million in costs and \$850.5 million in customer revenues (including Rider C collections and refunds) being attributed to 2005.

The AESO notes that revenue and cost transactions that occurred from January 1, 2005, to ~~July~~March 31, ~~2007~~2008 may also relate, in whole or in part, to years prior to 2005. 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 2005 and prior years for transactions which occurred in 2005, 2006, and 2007 is provided in Appendix E-1 ~~of~~of this application.

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 and 4 relating to 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 application section relating to 2005.

### **35.1 2005 Cost Variances**

Table ~~35~~-1 presents the AESO's 2005 revenue requirement as approved in ~~EUBAUC~~ Order U2005-464 dated December 20, 2005. Additional information on the AESO's 2005 revenue requirement is contained in ~~EUBAUC~~ Decisions 2005-015 on the AESO's 2005 Own Costs and 2005-096 on the AESO's 2005-2005 General Tariff Application, as well as in the AESO's 2005 General Tariff Application itself available on the AESO web site at www.aeso.ca by following the path Tariff ► Previous Applications ► 2005 Tariff Application (Application No. 1363012).

Table ~~35~~-1 also includes recorded costs as incurred for 2005, and variances between approved and recorded costs in both dollar amounts and as a percentage of approved costs.

Total 2005 recorded costs are ~~\$74.368.5~~ million (9%) higher than the total 2005 approved revenue requirement. This variance consists of 2005 recorded costs being:

- ~~\$2.4~~1.5 million (~~10.3~~) higher than ~~the~~ 2005 approved revenue requirement for wires,
- \$52.~~20~~ million (38%) higher for ancillary services,
- ~~\$21.015.1~~ million (~~128~~) higher for losses,
- \$2.5 million (31%) lower for other industry costs, and
- ~~\$1.12.4~~ million (~~48~~) higher for general and administrative costs,



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~~Variances arise due to a number of factors, including finalization of TFO costs through EUB 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  $\pm\$3.0$  million, which represents approximately 10% of the  $\$29.2$  million general and administrative costs component of the AESO's revenue requirement. A line item variance smaller than  $\pm\$3.0$  million is also considered significant when it is both at least  $\pm\$0.3$  million and at least  $\pm 10\%$  of the approved line item amount. The  $\pm\$0.3$  million threshold represents~~

Table 35-1 2005 Revenue Requirement and Recorded Costs, \$ 000 000

Line No.	Approved Forecast (a)	Recorded Costs (b)	Variance Over (Under)		
			\$ (c)=(b)-(a)	% (d)=(c)÷(a)	
<b>WIRES</b>					
<b>TFO's Wires-Related Costs</b>					
1	AltaLink	181.5	182.1	0.6	0.3%
2	ATCO Electric Ltd.	161.2	<del>164.6</del> 163.7	<del>3.4</del> 2.5	<del>2.1</del> 1.5%
3	Isolated Generation	(5.5)	(5.9)	(0.4)	7.5%
4	Subtotal ATCO Costs	155.7	<del>158.7</del> 157.8	<del>3.0</del>	<del>1.9</del> 1.3%
5	Enmax Power Corporation	33.6	34.1	0.5	1.4%
6	EPCOR Transmission Inc.	35.2	37.1	1.9	5.3%
7	City of Lethbridge	4.5	4.5	-	-
8	TransAlta	3.6	3.6	-	-
9	Refund to the AESO	n/a	n/a	n/a	n/a
10	Subtotal TransAlta Costs	3.6	3.6	-	-
11	City of Red Deer	1.8	1.8	0.0	1.0%
12	FortisAlberta Networks (Farm)	1.9	1.9	-	-
13	Subtotal TFO Wires-Related Costs	417.8	<del>423</del> 422.8	<del>5.0</del>	<del>1.2</del> 1.4%
<b>Non-Wires Costs</b>					
14	Invitation to Bid on Credits (IBOC)	1.9	1.7	(0.2)	(9.3%)
15	Location Based Credit Standing Offer (LBC SO)	7.5	4.1	(3.4)	<del>(45.0)</del> 4.8%
16	Subtotal IBOC/LBC SO Costs	9.4	<del>5.8</del> 5.9	<del>(3.6)</del> 5	<del>(37.8)</del> 6%
17	TOTAL WIRES COSTS	427.2	<del>429.6</del> 428.7	<del>2.4</del> 1.5	<del>0.6</del> 0.3%
<b>ANCILLARY SERVICES</b>					
<b>Operating Reserves</b>					
Active					
18	Regulating	27.0	38.6	11.6	42.8%
19	Spinning	29.2	44.1	14.9	51.0%
20	Supplemental	15.1	30.9	15.8	104.4%
21	Subtotal Active Reserves	71.3	113.5	42.2	59.2%
Standby					
22	Regulating	4.2	3.6	(0.6)	(15.4%)
23	Spinning	7.0	5.2	(1.8)	(26.0%)
24	Supplemental	1.9	2.2	0.3	14.2%
25	Subtotal Standby Reserves	13.1	10.9	(2.2)	(16.7%)
26	Trading Fees & Other Related Charges	-	(2.2)	(2.2)	-
27	Subtotal Operating Reserves	84.4	122.2	37.8	44.8%
<b>Other Ancillary Services</b>					
28	Generator Remedial Action Schemes (RAS)	0.4	0.5	0.1	12.5%
29	Black Start	2.3	1.6	(0.7)	(29.0%)
30	Transmission Must Run (TMR)	41.4	<del>56.4</del> 52	<del>15.0</del> 14.8	<del>36.3</del> 35.8%
31	Under Frequency Mitigation	6.5	6.3	(0.2)	(3.0%)
32	Subtotal Other Ancillary Services	50.6	<del>64.8</del> 66	<del>14.2</del> 14.8	<del>28.1</del> 27.7%

Table 35-1 2005 Revenue Requirement and Recorded Costs, \$ 000 000 (continued)

Line No.	Approved Forecast (a)	Recorded Costs (b)	Variance Over (Under)		
			\$ (c)=(b)-(a)	% (d)=(c)÷(a)	
<b>Poplar Hill/ILRAS</b>					
33	Poplar Hill	1.9	1.9	0.0	1.5%
34	Interruptible Load Remedial Action Scheme (ILRAS)	0.8	0.9	0.1	12.3%
35	<b>Subtotal Poplar Hill/ILRAS</b>	<b>2.7</b>	<b>2.8</b>	<b>0.1</b>	<b>4.7%</b>
36	<b>TOTAL ANCILLARY SERVICES</b>	<b>137.7</b>	<b>189.97</b>	<b>52.20</b>	<b>37.97%</b>
<b>LOSSES</b>					
37	Pool Payment	181.0	202.0	21.0	15.1%
38	Prior Year Losses Adjustments	-	-	-	-
39	One-time Settlement Data Adjustment	-	-	-	-
40	<b>TOTAL LOSSES COSTS</b>	<b>181.0</b>	<b>202.0</b>	<b>21.0</b>	<b>15.1%</b>
<b>OTHER INDUSTRY COSTS</b>					
41	External Regulatory Costs	5.0	2.7	(2.3)	(45.5%)
42	Western Electricity Coordination Council (WECC)	1.0	0.8	(0.2)	(15.5%)
43	Share of EUBAUC Overhead	1.8	1.8	(0.0)	(1.5%)
44	Balancing Pool	-	-	-	-
45	<b>TOTAL OTHER INDUSTRY COSTS</b>	<b>7.8</b>	<b>5.3</b>	<b>(2.5)</b>	<b>(31.5%)</b>
<b>GENERAL AND ADMINISTRATIVE COSTS</b>					
<b>Administrative Costs</b>					
46	Staff and Benefits	19.2	19.7	0.5	2.8%
47	Consultants	2.6	2.6	(0.0)	(0.0%)
48	Board Members Fees	0.3	0.4	0.1	39.7%
49	Travel and Training	1.0	0.8	(0.2)	(22.9%)
50	Legal	0.4	0.6	0.2	54.3%
51	Accounting and Tax Advice	0.3	0.2	(0.1)	(39.7%)
52	Rent <sup>1</sup>	1.2	1.2	0.0	1.5%
53	Insurance	0.5	0.4	(0.1)	(26.0%)
54	Other Administrative Costs	2.6	2.4	(0.2)	(8.2%)
55	Interconnection Fees (Offset)	(0.9)	(0.6)	0.3	(33.4%)
56	<b>Total Administrative Costs</b>	<b>27.2</b>	<b>27.7</b>	<b>0.5</b>	<b>1.8%</b>

Table 35-1 2005 Revenue Requirement and Recorded Costs, \$ 000 000 (continued)

Line No.	Approved Forecast (a)	Recorded Costs (b)	Variance Over (Under)	
			\$ (c)=(b)-(a)	% (d)=(c)÷(a)
<b>General Costs</b>				
57	0.3	0.4	0.1	33.3%
58	1.7	2.3	0.6	35.3%
59	-	-	-	-
60	2.0	2.6	0.6	30.0%
61	29.2	30.3	1.1	3.8%
62	37.0	35.7	(1.3)	(3.5%)
63	782.9	857.2	74.3	9.5%
64	4.5	5.9	1.4	31.1%

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 2005 Recorded Costs on Line 52

5 Variances arise due to a number of factors, including finalization of TFO costs through AUC 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 ±\$3.0 million, which represents approximately 10% of the \$29.2 million general and administrative costs component of the AESO's revenue requirement. A line item variance smaller than  
 10 ±\$3.0 million is also considered significant when it is both at least ±\$0.3 million and at least ±10% of the approved line item amount. The ±\$0.3 million threshold represents  
 approximately 1% of the \$29.2 million general and administrative costs component of the AESO's revenue requirement, while the AESO considers ±10% to be a reasonable threshold below which specific variance explanations are not required.

15 Variances exceeding these thresholds are shaded in Table 35-1, with explanations provided by line number in the following discussion. Where variances were either less than ±\$0.3 million or less than ±10% (except where such variance is ±\$3.0 million or greater)  
 20 explanations are not provided, as such variances are small enough that specific variance explanations are not required.

### 35.1.1 Wires Costs

25 The AESO's 2005 TFO wires costs forecast was based on TFO costs approved at the time of the AESO's 2005 tariff application or (in the case of AltaLink, ATCO Electric, and TransAlta) during the course of the proceeding. These costs were comprehensively summarized in section 2.2 of the AESO's 2006 General Tariff Application filed on January 31, 2005, and in response to Direction 4B in the AESO's 2005-2006 GTA Refiling on September 27, 2005.

The recorded 2005 wires costs were as billed by the TFOs to the AESO based on final 2005 tariffs approved for the TFOs.

**Line 2 ATCO Electric**

Although not resulting in a significant variance for 2005, this deferral account reconciliation includes several adjustments to ATCO Electric costs including a refund with respect to ATCO Electric's tax liability refiling as discussed in section 3.1.1 of this application.

The 2005 recorded cost for ATCO Electric wires was ~~\$164.6~~163.7 million, which is ~~\$3.42.5~~ million (or 2%) more than the 2005 approved forecast of \$161.2 million. The forecast cost was from EUBAUC Decision 2005-102 which approved ATCO Electric's 2005 Interim Transmission Facility Owner Tariff on an interim refundable basis, ~~while the~~. The recorded cost ~~reflected~~was based on:

- AUC Decision 2006-070 on ATCO Electric's 2005-2006 General Tariff Application Refiling, ~~including a which included a~~ final 2005 transmission revenue requirement. ~~The \$3.4 million shortfall between the 2005 of \$164.6 million;~~
- AUC Decision 2007-104 on ATCO Electric's 2007-2008 General Tariff Application Refiling which approved ~~forecast and the~~ a refund of future income taxes that ATCO Electric had collected from customers, of which \$2.5 million was applied as a refund to 2005 ~~recorded costs is simply the difference between ATCO Electric's interims~~ discussed in section 3.1.1 of this application, and
- AUC Decision U2007-071 on ATCO Electric's 2007-2008 General Tariff Application which approved ~~and final approved tariffs~~ a charge of \$1.5 million to the AESO with respect to 2005.

Other variances between recorded and forecast wires costs are not significant, and reflect costs paid in accordance with decisions and approvals subsequent to the AESO's 2005-2006 tariff application proceeding.

**Line 15 Location Based Credit Standing Offer (LBC SO)**

The LBC SO program provides increased system security, whereby the AESO retains dispatch rights to location-specific generation in return for location-based credits made up of fixed and variable payments. The 2005 recorded costs for LBC SO were \$4.1 million, which is \$3.4 million (or 45%) less than the 2005 approved forecast of \$7.5 million. This variance is due to significantly lower volumes in 2005 as compared to the forecast and to low availability in 2005 for one of the three LBC SO facilities which reduced the fixed payments to that facility for most of the year.

**35.1.2 Ancillary Services**

The recorded ancillary services costs for 2005 ~~totalled~~totalled \$189.97 million, which is \$52.20 million (or 38%) more than the 2005 approved forecast of \$137.7 million. The primary component of this variance is an increase in active operating reserves costs of \$42.2 million (or 59%) due to extremely high pool prices in the second half of 2005. A secondary component is an increase in transmission must run (TMR) costs of ~~\$15.0~~14.8 million (or 36%) due to lower than expected market heat rates and higher than expected gas prices. These cost increases were offset by reductions in the costs of standby operating reserves and black start service.

Detailed explanations of the variances of the 2005 recorded costs from the 2005 approved forecast are provided in the sections that follow.

5 **Lines 18 to 27 Operating Reserves**

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

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. In Alberta, regulating reserves track variations in the 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 MW over which a level of control is required by the AGC system.

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.

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.

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.

Operating reserves are procured through the Alberta Watt Exchange or directly from suppliers through Over-The-Counter transactions.

35 *Lines 18 to 21 Active Operating Reserves*

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. 2005 recorded costs were \$113.5 million, which is \$42.2 million (or 59%) more than the 2005 approved forecast of \$71.3 million, and comprised the following amounts:

- For active regulating reserve, the 2005 recorded cost was \$38.6 million, which is \$11.6 million (or 43%) more than the 2005 approved forecast of \$27.0 million.
- For active spinning reserve, the 2005 recorded cost was \$44.1 million, which is \$14.9 million (or 51%) more than the 2005 approved forecast of \$29.2 million.
- For active supplemental reserve, the 2005 recorded cost was \$30.9 million, which is \$15.8 million (or 104%) more than the 2005 approved forecast of \$15.1 million.



5 The increase in 2005 recorded costs compared to the approved forecast for all active operating reserves was due to a large increase in operating costs observed in the second half of 2005 as a result of pool price increases. In particular, recorded costs for active regulating and active spinning reserves were tracking forecasts costs very closely in the first half of 2005, after which pool prices increased considerably which caused these costs to increase.

10 Recorded active operating reserves volumes in 2005 were 4% lower than the approved forecast due to recorded Alberta internal load being 2.2% lower than forecast for 2005.

*Lines 22 to 25 Standby Operating Reserves*

15 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.

20 For standby regulating reserves premiums, the 2005 recorded cost was \$2.9 million, which is \$0.3 million (or 10%) more than the 2005 approved forecast of \$2.6 million due to increased pool prices during the second half of 2005 which commanded a slightly higher premium from the market. -The 2005 recorded volumes for premiums were 4% lower than forecast for 2005.

25 For standby regulating reserves activations, the 2005 recorded cost was \$0.7 million, which is \$0.9 million (or 57%) less than the 2005 approved forecast of \$1.5 million. This variance is due to 2005 recorded volumes for activations being 54% lower than forecast as a result of higher than forecast unit availability of regulating reserve providers and improved System Controller management of the system.

30 For standby spinning reserves premiums, the 2005 recorded cost was \$2.6 million, which is \$0.5 million (or 22%) more than the 2005 approved forecast of \$2.2 million due in part to slightly higher volumes arising from the occasional substitution of standby spinning reserves for standby supplemental reserves for cost-saving purposes.

35 For standby spinning reserves activations, the 2005 recorded costs was \$2.5 million, which is \$2.3 million (or 47%) less than the 2005 approved forecast of \$4.8 million due to higher than forecast availability of generating units and increased competition on the part of active spinning reserve providers. The 2005 recorded volumes for activations were 54% lower than forecast as a result of higher than forecast unit availability of regulating — reserve providers.

45 For standby supplemental reserves premiums, the 2005 recorded cost was \$0.9 million, which is \$0.2 million (or 27%) more than the 2005 approved forecast of \$0.7 million due to higher than expected pool prices in the second half of 2005 which commanded higher premium prices, offset by lower than forecast volumes arising from the occasional substitution of standby spinning reserves for standby supplemental reserves for cost-saving purposes.

For standby supplemental reserves activations, the 2005 recorded costs was \$1.2 million, which is \$0.1 million (or 7%) more than the 2005 approved forecast of \$1.2 million and is essentially comparable to the forecast.

5 | *Line 26 Trading Fees and Other Related Charges*

The 2005 recorded cost for trading fees and other related charges was a credit of \$2.2 million. No corresponding amount was included in the approved forecast. The variance arose from unforecast collections of non-compliance charges of \$2.8 million, offset by trading costs of \$0.6 million.

Other variances between recorded and forecast operating reserves costs are not significant, and reflect reasonable variability of recorded costs compared to forecast costs.

15 | **Lines 2928 to 3736 Other Ancillary Services**

Other ancillary services include the remaining services that the AESO procures for the secure and reliable operation of the AIES. These services are normally procured through bilateral contract negotiations with one or more suppliers, and include generator remedial action schemes (GRAS), black start, transmission must run (TMR), under frequency mitigation, Poplar Hill, and interruptible load remedial action scheme (ILRAS) services. The 2005 recorded cost of other ancillary services was ~~\$64.867.4~~ million, which is \$14.21 million (or ~~2827~~%) more than the 2005 approved forecast of ~~\$50.653.3~~ million, primarily due to both volumes and prices being higher than forecast for TMR.

25 | Black start service is provided by suppliers that have the ability to self-start, energize transmission lines, and provide start up power to other generators. This service is integral to the AESO's system restoration plan and enables timely restoration of electrical supply on the AIES in the unlikely event of a blackout. The 2005 recorded cost for black start service was \$1.6 million, which is \$0.7 million (or 29%) less than the 2005 approved forecast of \$2.3 million due to the AESO being unable to conclude contract negotiations with one black start service provider and concluding negotiations with another provider partway through 2005.

35 | 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 service is normally procured through commercial agreements negotiated between the AESO and suppliers. TMR agreements provide the AESO with dispatch rights to TMR generation to ensure adequate voltages are maintained following transmission or generation contingencies on the system. The 2005 recorded cost for TMR was \$56.42 million, which is ~~\$15.014.8~~ million (or 36%) more than the 2005 approved forecast of \$41.4 million, due to the requirement for Rossdale TMR not being forecast for 2005 and to higher gas prices and lower market heat rates than forecast for 2005.

45 | The 2005 recorded cost for TMR includes costs finalized in 2008 through a commercial agreement with ATCO Power for compensation for TMR service provided by the Rainbow Lake generating units, as discussed for Other Ancillary Services (Lines 28 to 36) in section 3.1.2 of this application. Under the agreement, no additional adjustments to compensation were made for TMR service provided by the Rainbow Lake generating units in 2005.

The 2005 recorded costs for the remaining other ancillary services (generator remedial action schemes (GRAS), under frequency mitigation, Poplar Hill, and interruptible load remedial action scheme (ILRAS)) did not vary significantly from the 2005 approved forecast.

### 35.1.3 Losses (Line 37)

Losses are the energy lost on the transmission system when power is transmitted from suppliers to loads. Losses are the residual of the metered generation plus scheduled imports less scheduled exports and less metered loads. Losses can vary significantly and are influenced by many factors, including load level, generation dispatch, and the level of exports and imports.

The 2005 recorded cost for losses was ~~\$202.0~~196.1 million, which is ~~\$21.0~~15.1 million (or ~~128~~128%) more than the 2005 approved forecast of \$181.0 million. This variance is due to higher than forecast pool prices in 2005, offset in part by recorded volumes of 2,847 GWh being 139 GWh (or 5%) less than the 2005 approved forecast of 2,986 GWh.

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. Although losses were accordingly not included in sections 3 and 4 relating to 2007 and 2006 respectively, this application does include losses-related adjustments which occurred after January 1, 2006 and which relate to 2005 and prior years. Revenue and cost adjustments related to losses continue to be attributed to relevant production months, and in particular include the \$6.2 million refund relating to Transmission Administrator (TA) Adjustments reflecting 2001-2005 changes to point-of-delivery meter volumes, mentioned in section 2.1.1 of this application.

From November 21, 2005 through December 31, 2007, the Alberta Department of Energy had suspended processing of TA Adjustments (PFAM adjustments related to metering at the transmission-distribution interface), pending resolution of issues related to such TA Adjustments. In April 2008 the AUC convened a working group to review the recommendations in the Settlement Zone Accuracy Working Group Final Report, and concluded there should be no further delay to the financial clearing of the TA Adjustments that had been suspended. The AUC accordingly advised the AESO that the suspension for processing TA Adjustments was removed, and financial settlement of the suspended adjustments should be prepared for inclusion in the AESO's 2004-2007 deferral account reconciliation application.

As the suspended TA Adjustments relate to metering at the transmission-distribution interface, processing the adjustments results in changes to transmission system losses volumes and the associated cost of losses. The impact on the cost of losses of processing the adjustments is provided in Table 5-2.

Although Table 5-2 lists the \$4.3 million refund arising from suspended TA Adjustments attributable to 2006, the AESO notes that amount will be addressed through Calibration Factor Rider E and is not included in this deferral account reconciliation application, as discussed in section 2.1.2 of this application.

The \$5.9 million refund arising from suspended TA Adjustments attributable to 2005 is reflected in the 2005 recorded cost of losses of \$196.1 million.

5

Table 5-2 Impact of Suspended TA Adjustments, \$ 000 000

<u>Production Year</u>	<u>Increase (Decrease) in Cost of Losses</u>	<u>Method of Collection (Refund)</u>	
		<u>Rider E in Q3-Q4 2008</u>	<u>Deferral Account Reconciliation</u>
2006	(\$4.3)	(\$4.3)	-
2005	(5.9)	-	(5.9)
2004	3.3	-	3.3
2003	(0.5)	-	(0.5)
2002	(1.0)	-	(1.0)
2001	(2.0)	-	(2.0)
<b>Net</b>	<b>(\$10.5)</b>	<b>(\$4.3)</b>	<b>(\$6.2)</b>

Note: Numbers may not add due to rounding.

#### **5.1.4 Other Industry Costs**

10 The 2005 recorded other industry costs were \$5.3 million, which is \$2.5 million (or 31%) less than the 2005 approved forecast of \$7.8 million, primarily due to recorded external regulatory costs being less than forecast.

#### **Line 41 External Regulatory Costs**

15 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.

20 The 2005 recorded external regulatory costs were \$2.7 million, which is \$2.3 million (45%) less than the 2005 approved forecast of \$5.0 million as a result of lower than forecast costs for the Edmonton-Calgary 500 kV Transmission Development Need Application proceeding in addition to substantially lower than forecast costs incurred for the AESO's 2005-2006 General Tariff Application proceeding.

25 The 2005 recorded costs for the remaining other industry costs (Western Electricity Coordinating Council (WECC) membership and the AESO's share of ~~Alberta Energy and Utilities Board (EUB)AUC~~ overhead) did not vary significantly from the 2005 approved forecast.

#### **35.1.5 General and Administrative Costs**

30 The 2005 recorded general and administrative costs were ~~\$30.331.6~~ million, which is ~~\$1.42.4~~ million (or 48%) more than the 2005 approved forecast of \$29.2 million. This variance was driven primarily by increases in the cost of staff and benefits, interest, and amortization and depreciation, and a decrease in interconnection fees collected, with  
35 smaller increases and decreases in other cost components offsetting each other.

**Line 55 Interconnection Fees (Offset)**

Interconnection fees are collected by the AESO from customers submitting applications for system access service, in accordance with the terms and conditions of the AESO's tariff. The 2005 recorded revenue offset from interconnection fees was \$0.6 million, which is \$0.3 million (or 33%) less than the 2005 approved forecast of \$0.9 million revenue offset, due to a decrease in application fees for interconnection compared to forecast.

**Line 56 Interest**

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; and
- amounts reflecting the recognition of interest on deferral account balances and its redistribution between production months to allow the appropriate allocation of costs under the extraordinary circumstances of this deferral account reconciliation application as detailed in section 2.3.

The 2005 recorded costs for interest expense were \$1.6 million, which is \$1.3 million (or 443%) more than the 2005 approved forecast of \$0.3 million. The \$1.6 million of recorded interest expense comprises \$0.3 million of interest expense as actually incurred during 2005, plus \$1.3 million reflecting the recognition and redistribution of interest discussed above. The variance between recorded and forecast costs is due primarily to the redistribution of interest to account for the extraordinary circumstances of this application.

**Line 58 Amortization and Depreciation**

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

- three (3) years for computer hardware, furniture, and office equipment;
- five (5) years for software development;
- the lease term for leasehold improvements; and
- other periods as appropriate for specific capital expenditures.

The 2005 recorded amortization and depreciation was \$2.3 million, which is \$0.6 million (or 32%) more than the 2005 approved forecast of \$1.7 million due to a larger than forecast portion of 2005 capital expenditures being allocated to the AESO's transmission function and to additional depreciation on 2004 transmission-related capital expenditures.

The 2005 recorded costs for the remaining general and administrative components did not vary significantly from the 2005 approved forecast.

**35.1.6 Capital (Line 64)**

Capital investment is required by the AESO for the development of IT infrastructure necessary to support the transmission function, for the new System Coordination Centre (SCC) for which construction began in September 2005, and for leasehold improvements, furniture, and equipment. Capital costs recorded in 2005 were \$5.9 million, which is \$1.4

million (or 31%) higher than the 2005 approved forecast due to \$2.1 million of costs incurred in 2005 for the SCC. Costs for the SCC were not included in the 2005 approved forecast, but were separately approved by the EUBAUC in Decision 2005-021 dated March 22, 2005 and updated in a cost variance report filed with the AUC on November 22, 2005, as discussed in section 3.1.5 of this application. The increase due to SCC costs was partially offset by decreases in other forecast capital costs, primarily due to the deferral of changes to the Real Time Systems program until the new SCC was complete.

### 35.2 2005 Revenue Variances

Table 5-3-2 presents AESO revenue forecast to be collected from base rates in effect during 2005. The table also includes recorded revenue as collected through 2005 base rates, as well as variances between forecast and recorded revenues in both dollar amounts and as a percentage of forecast revenue. (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.)

The AUC approved base rates to be in effect during 2005 in Order U2004-476. Those rates were derived from the AESO's 2004 revenue requirement (as approved in AUC Order U2004-429) and billing determinants. To calculate the 2005 forecast revenue presented in Table 5-3, the AESO applied the rates to its forecast of billing determinants for 2005 as filed in the AESO's 2005 General Tariff Application on October 3, 2004.

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 2005 recorded base rates revenue in column (b) of Table 5-3 totalled \$831.8 million, which is \$20.0 million (or 2%) more than the 2005 forecast revenue of \$811.8 million.

**Table 5-3** 2005 Base Rate Revenue Variances, \$ 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	257.6	258.6	1.1	0.4%
2	Operating Reserve	92.9	110.7	17.8	19.2%
3	Other System Support	2.5	2.4	(0.2)	(6.6%)
4	<b>Total DTS</b>	<b>353.0</b>	<b>371.7</b>	<b>18.7</b>	<b>5.3%</b>
<b>Supply Transmission Service</b>					
5	Interconnection	178.5	172.8	(5.7)	(3.2%)
6	Losses	185.5	180.7	(4.8)	(2.6%)

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7	Operating Reserve	94.8	106.5	11.7	12.4%
8	Total STS	458.8	460.1	1.3	0.3%
<b>Total DTS and STS</b>					
9	Interconnection	436.0	431.4	(4.6)	(1.1%)
10	Losses	185.5	180.7	(4.8)	(2.6%)
11	Operating Reserve	187.7	217.2	29.5	15.7%
12	Other System Support	2.5	2.4	(0.2)	(6.6%)
13	Total DTS and STS	811.8	831.8	20.0	2.5%

Note: Numbers may not add due to rounding.

~~tariff applications, and Rider C is therefore not included in this discussion of variances from forecast.)~~

~~The EUB approved base rates to be in effect during 2005 in Order U2004-476. Those rates were derived from the AESO's 2004 revenue requirement (as approved in EUB Order U2004-429) and billing determinants. To calculate the 2005 forecast revenue presented in Table 3-2, the AESO applied the rates to its forecast of billing determinants for 2005 as filed in the AESO's 2005 General Tariff Application on October 3, 2004.~~

~~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 2005 recorded base rates revenue in column (b) of Table 3-2 totaled \$831.8 million, which is \$20.0 million (or 2%) more than the 2005 forecast revenue of \$811.8 million.~~

This base rates revenue variance arises mainly from recorded operating reserve revenue of \$217.2 million, which is \$29.5 million (or 16%) more than the 2005 forecast revenue of \$187.7 million. Operating reserve charges in the AESO's 2005 tariff were determined as a percentage of pool price, and recorded pool price during 2005 averaged \$70.36/MWh — about 17% higher than the forecast pool price of \$59.92 in the AESO's 2005 General Tariff Application.

The base rate revenue variances for other DTS and STS rate components varied from near forecast ~~up~~ to 7% below forecast, which is considered small enough that specific variance explanations are not required.

### **35.3 2005 Deferral Account Balance**

Costs and revenue variances through the year give rise to deferral account balances. The deferral account balances for 2005 are summarized in Table ~~3-35-4~~, and reflect the 2005 recorded costs and revenue provided in Tables ~~35-1~~ and ~~5-3-2~~ respectively. Table ~~3-35-4~~ also includes Deferral Account Adjustment Rider C, which collects or refunds revenue to align actual revenues with actual costs by rate and rate component.

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

5 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 the quarter and forecast billing volumes for the quarter.

10 The total recorded revenue collected with respect to 2005 is therefore the sum of revenue collected through base rates as discussed in section 35.2, plus revenue collected or refunded through Rider C during 2005 and in the first quarter of 2006. The goal of Rider C is to provide total revenue which aligns more closely with total costs incurred than would be possible through the use of base rates only.

15 As a result of changes implemented with the AESO's 2006 tariff as discussed in section 2.1.2 of this application, STS customers are not subject to Rider C adjustments for variances with respect to production months in 2006 and later years. However, a final Rider C was implemented for STS customers in the first two months of 2006 to collect a shortfall in the STS deferral accounts estimated to remain at the end of 2005. Table 3-35-4 therefore includes the Rider C amounts collected from STS customers in January and February 2006. For DTS customers, Table 5-4 includes a portion of the Rider C amounts refunded in the first quarter of 2006, reflecting that portion of the rider which refunded the surplus in the DTS deferral accounts that was estimated to remain at the end of 2005. The allocation between 2005 and 2006 of Rider C amounts charged or refunded in 2006 is reconciled in Appendix E-1 of this application.

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**Table 5-4** 2005 Deferral Account Summary, \$ 000 000

Line No.	Recorded Base Rate Revenue (a)	Recorded Costs (b)	Over (Under) Collection (c)=(a)+(b)	Rider C Collected (Refunded) (d)	Net Over (Under) Collection Variance		
					\$ (e)=(c)+(d)	% (f)=- (e)÷(b)	
<b>Demand Transmission Service</b>							
1	Interconnection	258.6	(270.2)3	(11.6)7	6.0	(5.5)6	(2.1)%
2	Operating Reserve	110.7	(93.5)4	17.2	(15.9)	1.3	1.4%
3	Other System Support	2.4	(2.5)4	(0.1)	0.6	0.5-6	22.323.7%
4	<b>Total DTS</b>	<b>371.7</b>	<b>(366.2)</b>	<b>5.5</b>	<b>(9.2)</b>	<b>(3.7)</b>	<b>(1.0)%</b>
<b>Supply Transmission Service</b>							
5	Interconnection	172.8	(195.4)5	(22.6)7	17.8	(4.8)	(2.45)%
6	Losses	180.7	(202.0)(196.3)	(21.3)(15.5)	22.8	1.5-7.3	03.7%
7	Operating Reserve	106.5	(93.5)4	13.0-1	(12.7)	0.3	0.34%
8	<b>Total STS</b>	<b>460.1</b>	<b>(491.0)(485.2)</b>	<b>(30.9)(25.1)</b>	<b>27.9</b>	<b>(3.0)2.8</b>	<b>(0.6)%</b>
<b>Total DTS and STS</b>							
9	Interconnection	431.4	(465.6)8	(34.2)3	23.9	(10.3)5	(2.2)%
10	Losses	180.7	(202.0)(196.3)	(21.3)(15.5)	22.8	1.5-7.3	03.7%
11	Operating Reserve	217.2	(187.1)(186.9)	30.2-3	(28.6)	1.5-7	0.89%
12	Other System Support	2.4	(2.5)4	(0.1)	0.6	0.5-6	22.323.7%
13	<b>Total DTS and STS</b>	<b>831.8</b>	<b>(857.2)(851.4)</b>	<b>(25.4)(19.6)</b>	<b>18.7</b>	<b>(6.8)(0.9)</b>	<b>(0.81)%</b>

Note: Numbers may not add due to rounding.

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~~provide total revenue which aligns more closely with total costs incurred than would be possible through the use of base rates only.~~

10

~~As a result of changes implemented with the AESO's 2006 tariff, STS customers are not subject to Rider C adjustments for variances with respect to production months in 2006 and later years. However, a final Rider C was implemented for STS customers in the first two months of 2006 to collect a shortfall in the STS deferral accounts estimated to remain at the end of 2005. Table 3-3 therefore includes the Rider C amounts collected from STS customers in January and February 2006. For DTS customers, Table 3-3 includes a portion of the Rider C amounts refunded in the first quarter of 2006, reflecting that portion of the rider which refunded the surplus in the DTS deferral accounts that was estimated to remain at the end of 2005. The allocation between 2005 and 2006 of Rider C amounts charged or refunded in 2006 is reconciled in Appendix N of this application.~~

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In general, Rider C collections and refunds for 2005 maintained net deferral account balances at reasonable levels of less than  $\pm 34\%$  of costs for all rate components except



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DTS other system support charges, which were overcollected by 2224% of costs. However, at only 0.3% of the AESO's annual revenue requirement, DTS other system support costs represent the smallest AESO rate component. In absolute terms the associated variance represented only a \$0.56 million overcollection over the year.

Additional details on 2005 recorded revenues and costs 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 79 of this application.

## **46 2004 FINANCIAL RESULTS AND DEFERRAL ACCOUNT BALANCE**

In determining the financial results and deferral account balance for 2004, all revenue and cost transactions that occurred from January 1, 2004, to ~~July~~March 31, ~~2007~~2008 and that relate to 2004 have been included in the reconciliations. These transactions establish the 2004 production month data for deferral account reconciliation purposes in this application. The net result of these transactions is ~~\$689.8691.1~~ million in costs and \$685.7 million in customer revenues (including Rider C collections and refunds) being attributed to 2004.

The AESO notes that revenue and cost transactions that occurred from January 1, 2004, to ~~July~~March 31, ~~2007~~2008 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 2007 is provided in Appendix E-1 of this application.

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 and 4 relating to 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.

### **6.1 2004 Cost Variances**

Table ~~36~~36-1 presents the AESO's 2004 revenue requirement as approved in ~~EUBAUC~~EUBAUC Decisions 2004-012 (for 2004 "Own Costs") and 2005-005 (for 2004 other costs) and in ~~EUBAUC~~EUBAUC Order U2004-429 (for 2004 total revenue requirement). Additional information on the AESO's 2004 revenue requirement is contained in the Decisions, as well as in the AESO's 2004 General Tariff Application itself (Applications No. 1322864 and No. 1343002).

Table ~~46~~46-1 also includes recorded costs as incurred for 2004, and variances between approved and recorded costs in both dollar amounts and as a percentage of approved costs.

Total 2004 recorded costs are ~~\$67.666.3~~ million (9%) lower than the total 2004 approved revenue requirement. This variance consists of 2004 recorded costs being:

- ~~\$9.48.8~~ million (2%) lower than 2004 approved revenue requirement for wires,
- ~~\$40.242.6~~ million (~~2426~~2426%) lower for ancillary services,
- ~~\$17.714.4~~ million (~~119~~119%) lower for losses,
- \$2.3 million (32%) lower for other industry costs, and
- ~~\$1.78~~ million (7%) higher for general and administrative costs.

~~Variances arise due to a number of factors, including finalization of TFO costs through EUB decisions, variances from forecast of volumes and pool price, delays and changes in AESO~~

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~~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  $\pm$ \$3.0 million, which represents approximately 10% of the \$24.7 million general and administrative costs component of the AESO's revenue requirement. A line item variance smaller than  $\pm$ \$3.0 million is also considered significant when it is both at least  $\pm$ \$0.3 million and at least  $\pm$ 10% of the approved line item amount. The  $\pm$ \$0.3 million threshold represents approximately 1% of the \$24.7 million general and administrative costs component of the~~

Table 46-1 2004 Revenue Requirement and Recorded Costs, \$ 000 000

Line No.	Approved Forecast	Recorded Costs	Variance Over (Under)			
			\$	%		
	(a)	(b)	(c)=(b)-(a)	(d)=(c) $\div$ (a)		
<b>WIRES</b>						
<b>TFO's Wires-Related Costs</b>						
1	AltaLink	160.3	157.5	(2.9)	(1.8%)	
2	ATCO Electric Ltd.	170.0	152.14	(17.96)	(10.64%)	
3	Isolated Generation	(5.1)	(4.8)	0.3	(6.8%)	
4	Subtotal ATCO Costs	164.9	147.36	(17.63)	(10.75%)	
5	Enmax Power Corporation	33.4	33.2	(0.2)	(0.6%)	
6	EPCOR Transmission Inc.	30.6	32.8	2.2	7.2%	
7	City of Lethbridge	4.4	4.5	0.1	1.8%	
8	TransAlta	2.3	3.4	1.1	48.6%	
9	Refund to the AESO	(9.9)	-	9.9	(100.0%)	
10	Subtotal TransAlta Costs	(7.6)	3.4	11.0	(145.0%)	
11	City of Red Deer	1.8	1.8	0.0	1.4%	
12	FortisAlberta Networks (Farm)	1.9	1.9	-	-	
13	<b>Subtotal TFO Wires-Related Costs</b>	<b>389.7</b>	<b>382.47</b>	<b>(7.30)</b>	<b>(1.98%)</b>	
<b>Non-Wires Costs</b>						
14	Invitation to Bid on Credits (IBOC)	3.2	2.1	(1.1)	(34.4%)	
15	Location Based Credit Standing Offer (LBC SO)	6.4	5.7	(0.7)	(10.7%)	
16	<b>Subtotal IBOC/LBC SO Costs</b>	<b>9.6</b>	<b>7.8</b>	<b>(1.8)</b>	<b>(18.6%)</b>	
17	<b>TOTAL WIRES COSTS</b>	<b>399.3</b>	<b>390.25</b>	<b>(9.1)</b>	<b>(8.8)</b>	<b>(2.32%)</b>
<b>ANCILLARY SERVICES</b>						
<b>Operating Reserves</b>						
<b>Active</b>						
18	Regulating	36.4	25.1	(11.3)	(31.0%)	
19	Spinning	38.8	25.7	(13.1)	(33.8%)	
20	Supplemental	8.5	11.1	2.6	30.8%	
21	<b>Subtotal Active Reserves</b>	<b>83.7</b>	<b>61.9</b>	<b>(21.8)</b>	<b>(26.0%)</b>	
<b>Standby</b>						
22	Regulating	8.4	2.8	(5.6)	(67.2%)	
23	Spinning	10.2	4.4	(5.8)	(57.1%)	
24	Supplemental	2.7	1.3	(1.4)	(50.4%)	
25	<b>Subtotal Standby Reserves</b>	<b>21.3</b>	<b>8.5</b>	<b>(12.8)</b>	<b>(60.2%)</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>(35.8)</b>	<b>(34.1%)</b>	

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**Other Ancillary Services**

28	Generator Remedial Action Schemes (RAS)	0.4	0.4	(0.0)	(9.5%)	2.0%
29	Black Start	2.2	1.0	(1.2)	(54.5%)	
30	Transmission Must Run (TMR)	49.3	46.3	(3.0)	(5.4)	(6.1)
31	Under Frequency Mitigation	6.5	6.9	0.4	5.5%	
32	Hydro Motoring	-	-	-	-	-
33	<b>Subtotal Other Ancillary Services</b>	<b>58.4</b>	<b>54.5</b>	<b>(3.9)</b>	<b>(6.2)</b>	<b>(6.6)</b>

**Table 46-1 2004 Revenue Requirement and Recorded Costs, \$ 000 000 (continued)**

Line No.	Approved Forecast	Recorded Costs	Variance Over (Under)			
			\$	%		
	(a)	(b)	(c)=(b)-(a)	(d)=(c)÷(a)		
<b>Poplar Hill/ILRAS</b>						
34	Poplar Hill	1.8	1.9	0.1	4.8%	
35	Interruptible Load Remedial Action Scheme (ILRAS)	1.1	0.6	(0.5)	(49.7)	53.9%
36	<b>Subtotal Poplar Hill/ILRAS</b>	<b>2.9</b>	<b>2.4</b>	<b>(0.5)</b>	<b>(15.9)</b>	<b>17.4%</b>
37	<b>TOTAL ANCILLARY SERVICES</b>	<b>166.3</b>	<b>126.1</b>	<b>(40.2)</b>	<b>(42.6)</b>	<b>(24.1)</b>
<b>LOSSES</b>						
38	Pool Payment	159.9	142.2	(17.7)	(14.4)	(11.9)
39	Losses Studies Surcharge	-	-	-	-	-
40	<b>TOTAL LOSSES COSTS</b>	<b>159.9</b>	<b>142.2</b>	<b>(17.7)</b>	<b>(14.4)</b>	<b>(11.9)</b>
<b>OTHER INDUSTRY COSTS</b>						
41	External Regulatory Costs	4.4	2.3	(2.1)	(47.3%)	
42	Western Electricity Coordination Council (WECC)	0.9	0.8	(0.1)	(10.2%)	
43	Share of EUBAUC Overhead	2.0	1.8	(0.2)	(8.4%)	
44	Balancing Pool	-	-	-	-	-
45	<b>TOTAL OTHER INDUSTRY COSTS</b>	<b>7.3</b>	<b>5.0</b>	<b>(2.3)</b>	<b>(32.0%)</b>	
<b>GENERAL AND ADMINISTRATIVE COSTS</b>						
<b>Administrative Costs</b>						
46	Staff and Benefits	16.0	16.8	0.8	5.1%	
47	Interconnection Fees (Offset)	(0.9)	(0.7)	0.2	(21.0%)	
48	<b>Subtotal Staff &amp; Benefits</b>	<b>15.1</b>	<b>16.1</b>	<b>1.0</b>	<b>6.6%</b>	
49	Consultants	2.9	3.9	1.0	33.2%	
50	Interconnection Fees (Offset)	-	(0.4)	(0.4)	-	-
51	<b>Subtotal Consultants</b>	<b>2.9</b>	<b>3.5</b>	<b>0.6</b>	<b>19.3%</b>	
52	Board Members Fees	0.3	0.3	0.0	14.3%	
53	Travel and Training	1.0	1.0	0.0	1.4%	
54	Legal	0.4	0.4	0.0	10.8%	
55	Accounting and Tax Advice	0.3	0.0	(0.3)	(87.3%)	
56	Rent	1.0	0.9	(0.1)	(5.5%)	
57	Insurance	0.3	0.3	0.0	14.7%	
58	Other Administrative Costs	1.4	2.2	0.8	56.6%	
59	Negotiated Settlement Reduction	-	-	-	-	-
60	<b>Total Administrative Costs</b>	<b>22.8</b>	<b>24.9</b>	<b>2.2</b>	<b>9.6%</b>	

Table 46-1 2004 Revenue Requirement and Recorded Costs, \$ 000 000 (continued)

Line No.	Approved Forecast (a)	Recorded Costs (b)	Variance Over (Under)	
			\$ (c)=(b)-(a)	% (d)=(c)÷(a)
<b>General Costs</b>				
61	0.1	0.23	0.12	112.0%
62	1.8	1.6	(0.2)	(11.6%)
63	-	-	-	-
64	-	-	-	-
65	-	(0.4)	(0.4)	-
66	1.9	1.45	(0.54)	(28.25%)
67	24.7	26.34	1.78	7.1%
68	32.0	31.23	(0.76)	(2.38%)
69	757.5	689.8	(67.6)	(8.98%)
70	3.3	5.2	1.9	57.6%

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 2004 Recorded Costs on Line 56

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Variances arise due to a number of factors, including finalization of TFO costs through AUC 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 ±\$3.0 million, which represents approximately 10% of the \$24.7 million general and administrative costs component of the AESO's revenue requirement. A line item variance smaller than ±\$3.0 million is also considered significant when it is both at least ±\$0.3 million and at least ±10% of the approved line item amount. The ±\$0.3 million threshold represents approximately 1% of the \$24.7 million general and administrative costs component of the AESO's revenue requirement, while the AESO considers ±10% to be a reasonable threshold below which specific variance explanations are not required.

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Variances exceeding these thresholds are shaded in Table 46-1, with explanations provided by line number in the following discussion. Where variances were either less than ±\$0.3 million or less than ±10% (except where such variance is ±\$3.0 million or greater) explanations are not provided, as such variances are considered small enough that specific variance explanations are not required.

20

**46.1.1 Wires Costs**

The AESO's 2004 TFO wires costs forecast was based on TFO costs approved at the time of the AESO's 2004 tariff application or (in the cast of AltaLink and TransAlta) during the course of the proceeding. These costs were comprehensively summarized in the attachment to Information Response CAL.AESO-17 in the AESO's 2004 Phase I Revenue Requirement proceeding.

25

The recorded 2004 wires costs were as billed by the TFOs to the AESO based on final 2004 tariffs approved for the TFOs.

**Line 2 ATCO Electric**

The 2004 recorded cost for ATCO Electric wires was \$152.44 million, which is \$17.96 million (or 11.8%) less than the 2004 approved forecast of \$170.0 million. The forecast cost was from EUBAUC Decisions 2004-014 and 2004-016 which approved ATCO Electric's 2003-2004 GTA Refiling, including several amounts ~~in Decision 2004-014 which~~ related to 2002 and 2003 which had been included in Decision 2004-014 (as detailed in Information Response CAL.AESO-17).

The \$17.96 million surplus between the 2004 approved forecast and the 2004 recorded costs results from ~~the~~:

- amounts ~~with respect~~ related to 2002 and 2003 being appropriately attributed to those years (rather than to 2004) in accordance with the production month presentation of data as discussed in section 2.2 of this application. ~~The 2004 recorded costs also include~~;
- amounts ~~approved in Decision 2004-104 on ATCO Electric's 2003 Deferral Accounts but~~ arising from ATCO Electric's annual filing for adjustments relating to 2004. ~~as approved in Decision 2004-104 on ATCO Electric's 2003 Deferral Accounts; and~~
- amounts approved in Decision 2007-104 on ATCO Electric's 2007-2008 General Tariff Application Refiling respecting a refund of future income taxes that ATCO Electric had collected from customers, of which \$0.3 million was applied as a charge to 2004 as discussed in section 3.1.1 of this application

In summary, the 2004 recorded costs reflect ATCO Electric's wires costs for 2004 only, as approved in those decisions.

**Lines 8 and 9 TransAlta**

The 2004 recorded cost for TransAlta was \$3.4 million, which is \$1.1 million (or 49%) more than the 2004 approved forecast of \$2.3 million. The forecast cost was from EUBAUC Decision 2004-028 on TransAlta's Final TFO Tariff for January through April 2004 and Decision 2004-046 on TransAlta's Interim Transmission Tariff for May through December 2004, while the recorded cost reflected Decision 2005-082 on TransAlta's Final Transmission Tariff for May through December 2004. The \$1.1 million surplus between the 2004 approved forecast and the 2004 recorded costs is simply the difference between TransAlta's interim approved and final approved tariffs.

The approved forecast costs for TransAlta also included a \$9.9 million refund from TransAlta to the AESO, which has been excluded from 2004 recorded costs. The refund has instead been more appropriately recorded as costs in 2001 and 2002 as it related to transmission costs in those years, as discussed in sections 68.1 and 68.2 of this application. The 2004 recorded costs reflect TransAlta's wires costs for 2004 only, as approved in the referenced decisions.

Other variances between forecast and recorded wires costs are not significant, and reflect costs paid in accordance with later decisions and approvals, and the exclusion of forecast costs related to prior years.

#### Line 14 Invitation to Bid on Credits (IBOC)

5 The IBOC program provides a financial credit to specific generators in the Calgary area based on the volume of megawatt-hours they generate each month. The 2004 recorded cost for IBOC was \$2.1 million, which is \$1.1 million (or 34%) less than the 2004 approved forecast of \$3.2 million as two of the three IBOC units were routinely ineligible for IBOC payments during 2004.

#### Line 15 Location Based Credit Standing Offer (LBC SO)

10 The LBC SO program provides increased system security, whereby the AESO retains dispatch rights to location-specific generation in return for location-based credits made up of fixed and variable payments. The 2004 actual costs for LBC SO were \$5.7 million, which is \$0.7 million (or 11%) less than the 2004 approved forecast of \$6.4 million, due to lower recorded volumes in 2004 as compared to the forecast.

#### 46.1.2 Ancillary Services

15 Cost variances for ancillary services generally remain as detailed in the AESO's 2005-2006 General Tariff Application.

20 The recorded ancillary services costs for 2004 ~~totalled \$126.4~~ totalled \$123.7 million, which is ~~\$40.242.6~~ million (or ~~2426~~%) less than the 2004 approved forecast of \$166.3 million. The primary component of this variance is a decrease in operating reserve costs of \$35.8 million (or 34%), due to increased competition among operating reserve providers and higher than expected unit availability.

25 Detailed explanations of the variances of the 2004 recorded costs from the 2004 approved forecast are provided in the sections that follow.

#### Lines 18 to 27 Operating Reserves

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

35 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. In Alberta, regulating reserves track variations in the 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 MW over which a level of control is required by the AGC system.

45 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.

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.

5 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”~~), Alberta must comply with WECC policies for maintaining specific volumes of spinning and supplemental reserves in order to maintain reliability.

10 Operating reserves are procured through the Alberta Watt Exchange or directly from suppliers through Over-The-Counter transactions.

*Lines 18 to 21 Active Operating Reserves*

15 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. 2004 recorded costs were \$61.9 million, which is \$21.8 million (or 26%) less than the 2004 approved forecast of \$83.7 million.

- For active regulating reserve, the 2004 recorded cost was \$25.1 million, which is \$11.3 million (or 31%) less than the 2004 approved forecast of \$36.4 million.
- 20 • For active spinning reserve, the 2004 recorded cost was \$25.7 million, which is \$13.1 million (or 34%) less than the 2004 approved forecast of \$38.8 million.
- For active supplemental reserve, the 2004 recorded cost was \$11.1 million, which is \$2.6 million (or 31%) more than the 2004 approved forecast of \$8.5 million.

25 The decrease in recorded costs compared to the approved forecast for active regulating and active spinning reserves was due to increased competition on the part of operating reserve providers and higher than expected availability of generating units. The increase in recorded costs compared to the approved forecast for active supplemental reserve is due to the amendment to the active supplemental notional volumes in the Hydro PPA which came into effect in August 2004.

35 The active operating reserves variance also incorporates a 3% increase in 2004 recorded volumes compared to 2004 forecast volumes. The increase in volumes for all active reserves was due to AIES load being 3.2% higher than forecast for 2004. The 2004 approved forecast was based on an outlook that the Alberta economy was expected to suffer during 2004 due to factors such as the detection of BSE (bovine spongiform encephalopathy or “mad cow disease”) in an Alberta cow and the SARS (severe acute respiratory syndrome) international outbreak in 2003.

40 *Lines 22 to 25 Standby Operating Reserves*

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.

45

5 For standby regulating reserves premiums, the 2004 recorded cost was \$2.1 million, which is \$0.5 million (or 19%) less than the 2004 approved forecast of \$2.6 million, due to increased competition on the part of operating reserve providers which led to a reduction in costs. The 2004 recorded volumes for premiums were similar to the 2004 approved forecast.

10 For standby regulating reserves activations, the 2004 recorded cost was \$0.6 million, which is \$5.2 million (or 90%) less than the 2004 approved forecast of \$5.8 million. This variance is due to 2004 recorded volumes for activations being 80% lower than forecast as a result of higher than forecast unit availability of regulating reserve providers and increased competition on the part of operating reserve providers.

15 For standby spinning reserves premiums, the 2004 recorded cost was \$2.0 million, which is \$0.4 million (or 17%) less than the 2004 approved forecast of \$2.4 million, due to increased competition on the part of operating reserve providers which led to a reduction in costs. The 2004 recorded volumes for premiums increased 5% above the 2004 approved forecast, primarily due to AIES load being 3.2% higher than forecast for 2004, as discussed above for active reserves.

20 For standby spinning reserves activations, the 2004 recorded cost was \$2.4 million, which is \$5.4 million (or 69%) less than the 2004 approved forecast of \$7.8 million, due to higher than expected availability of generating units and increased competition on the part of operating reserve providers. The 2004 recorded volumes for activations were 54% lower than forecast as a result of higher than forecast unit availability of spinning reserve providers.

25 For standby supplemental reserves premiums, the 2004 recorded cost was \$0.6 million, which is \$0.2 million (or 25%) less than the 2004 approved forecast of \$0.8 million, due to increased competition on the part of operating reserve providers. The 2004 recorded volumes for premiums were similar to the 2004 approved forecast.

30 For standby supplemental reserves activations, the 2004 recorded cost was \$0.7 million which is \$1.2 million (or 63%) less than the 2004 approved forecast of \$1.9 million. The decrease in activation costs is due to increased competition on the part of operating reserve providers and higher than expected availability. The 2004 actual volumes for activations were 14% less than forecast due to higher than forecast unit availability of supplemental reserve providers.

#### *Line 26 Trading Fees and Other Related Charges*

40 The 2004 recorded cost for trading fees and other related charges was a credit of \$1.2 million. No corresponding amount was included in the approved forecast. The variance arose from unforecast collections of non-compliance charges of \$1.8 million, offset by trading costs of \$0.6 million.

#### **Lines 28 to 36 Other Ancillary Services**

45 Other ancillary services include the remaining services that the AESO procures for the secure and reliable operation of the AIES. These services are normally procured through bilateral contract negotiations with one or more suppliers, and include generator remedial

5 action schemes (GRAS), black start, transmission must run (TMR), under frequency mitigation, hydro motoring, Poplar Hill, and interruptible load remedial action scheme (ILRAS) services. The 2004 recorded cost of other ancillary services was \$~~57.0~~54.6 million, which is \$~~4.3~~6.7 million (or 711%) less than the 2004 approved forecast of \$61.3 million, primarily due to volume requirements for less efficient TMR units being less than forecast for 2004.

10 Black start service is provided by suppliers that have the ability to self-start, energize transmission lines, and provide start up power to other generators. This service is integral to the AESO's system restoration plan and enables timely restoration of electrical supply on the AIES in the unlikely event of a blackout. The 2004 recorded cost was \$1.0 million, which is \$1.2 million (or 55%) less than 2004 approved forecast of \$2.2 million, due to prolonged contract negotiations with some Black Start service providers.

15 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 service is normally procured through commercial agreements negotiated between the AESO and suppliers. TMR agreements provide the AESO with dispatch rights to TMR generation to ensure adequate voltages are maintained following transmission or generation contingencies on the system. The 2004  
20 recorded cost for TMR was \$~~46.3~~43.9 million, which is \$~~3.0~~5.4 million (or 611%) less than the 2004 approved forecast of \$49.3 million, primarily due to volume requirements for less efficient TMR units being lower than forecast for 2004.

25 The 2004 recorded cost for TMR includes costs finalized in 2008 through a commercial agreement with ATCO Power for compensation for TMR service provided by the Rainbow Lake generating units, as discussed for Other Ancillary Services (Lines 28 to 36) in section 3.1.2 of this application. Under the agreement, no additional adjustments to compensation were made for TMR service provided by the Rainbow Lake generating units in 2004.

30 Interruptible load remedial action scheme (ILRAS) 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  
35 situations to limit the frequency decline and attempt to prevent shedding of additional system load. The 2004 recorded cost for ILRAS service was \$~~0.6~~5 million, which is \$~~0.5~~6 million (or 5054%) less than the 2004 approved forecast of \$1.1 million. The variance is due to the forecast cost including an estimate of incremental costs related to the procurement of ILRAS from new suppliers. However, the agreement with FortisAlberta remained in effect  
40 throughout 2004 and, as such, increased costs related to procuring new supply was not incurred.

45 The 2004 recorded costs for the remaining other ancillary services (generator remedial action schemes (RAS), under frequency mitigation, and Poplar Hill) did not vary significantly from the 2004 approved forecast.

### 46.1.3 Losses (Line 38)

Losses are the energy lost on the transmission system when power is transmitted from suppliers to loads. Losses are the residual of the metered generation plus scheduled imports less scheduled exports and less metered loads. Losses can vary significantly and are influenced by many factors, including load level, generation dispatch and the level of imports or exports.

The 2004 recorded cost for losses was \$~~142.2145.5~~ million, which is \$~~17.714.4~~ million (or ~~119~~%) less than the 2004 approved forecast of \$159.9 million. The variance is due to a combination of higher volumes in low pool price hours and lower volumes in high price hours as compared to forecast. The 2004 recorded cost for losses is also less than forecast in part because the 2004 recorded losses volumes of 2,862 GWh are 11 GWh (or 0.4%) lower than the 2004 approved forecast of 2,873 GWh. This small losses volume variance demonstrates the AESO's continued improvements in the accuracy of its losses forecasts.

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. Although losses were accordingly not included in sections 3 and 4 relating to 2007 and 2006 respectively, this application does include losses-related adjustments which occurred after January 1, 2006 and which relate to 2005 and prior years. Revenue and cost adjustments related to losses continue to be attributed to relevant production months, and in particular include the \$3.3 million charge arising from suspended TA Adjustments attributable to 2004 as discussed in section 5.1.3 of this application.

### 6.1.4 Other Industry Costs

The 2004 recorded other industry costs were \$5.0 million, which is \$2.3 million (or 32%) less than the 2004 approved forecast of \$7.3 million, primarily due to recorded external regulatory costs being less than forecast.

### Line 41 External Regulatory Costs

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.

The 2004 recorded external regulatory costs were \$2.3 million, which is \$2.1 million (47%) less than the 2004 approved forecast of \$4.4 million, due to the delay of major hearings such as that for the Edmonton-Calgary 500 kV Transmission Development Need Application.

The 2004 recorded costs for the remaining other industry costs (Western Electricity Coordinating Council (WECC) membership and the AESO's share of Alberta ~~Energy and Utilities Board (EUB Commission (AUC))~~ overhead) did not vary significantly from the 2004 approved forecast.

### 46.1.5 General and Administrative Costs

The 2004 recorded general and administrative costs were \$26.~~34~~ million, which is \$1.~~78~~ million (7%) higher than the 2004 approved forecast of \$24.7 million. This variance was

driven primarily by a net increase in staff and benefits and consultants of \$1.6 million, with smaller increases and decreases in other general and administrative costs offsetting each other.

5 **Line 51 Consultants**

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 2004 recorded consulting costs were \$3.5 million, which is \$0.6 million (19%) higher than the 2004 approved forecast of \$2.9 million, net of the interconnection application fees offset. This variance is due to increases in the following areas during 2004:

- project management and technical support related to the Edmonton-Calgary 500 kV Transmission Development Need Application,
- interconnection applications,
- loss factors calculation support, and
- business process review

Additional detail on 2004 consulting costs is available in section 3.1 of the AESO's 2006 General Tariff Application filed on January 31, 2005 and available on the AESO web site at [www.aeso.ca](http://www.aeso.ca) by following the path Tariff ► Previous Applications ► 2006 Tariff Application (Application No. 1363012).

25 **Line 55 Accounting and Tax Advice**

Accounting and tax advice relates primarily to financial and operational audit fees. The 2004 recorded costs were \$0.04 million, which is \$0.3 million (or 87%) less than the 2004 approved forecast of \$0.3 million due to the deferral of a significant portion of the forecast costs into 2005 as a result of starting the operational review in the latter part of 2004.

30 **Line 58 Other Administrative Costs**

Other administrative costs include telecommunications, information technology (IT) maintenance and services, corporate subscriptions, memberships and professional fees, and general office costs. The 2004 recorded costs were \$2.2 million, which is \$0.8 million (or 57%) higher than the 2004 approved forecast of \$1.4 million, as provided in Table 46-2.

**Table 6-2** 2004 Other Administrative Costs Detail, \$ 000 000

Line No.	Approved Forecast (a)	Recorded Costs (b)	Variance Over (Under)	
			\$ (c)=(b)-(a)	% (d)=(c)÷(a)
58.1	0.4	0.5	0.1	25%
58.2	0.6	0.7	0.1	17%
58.3	0.4	1.0	0.6	150%
58	1.4	2.2	0.8	57%

and general office costs. The 2004 recorded costs were \$2.2 million, which is \$0.8 million (or 57%) higher than the 2004 approved forecast of \$1.4 million, as provided in Table 5-2.

The 2004 recorded telecommunications and IT costs are higher than the 2004 approved forecast as a result of unanticipated costs in the following areas:

- additional network links and capacity to support the System Coordination Centre;
- the consolidation of systems into the AESO's new office location; and
- additional software licenses.

The increase of recorded office costs and subscriptions above the approved forecast is primarily attributed to the following:

- The level of printing and advertising costs required for the various Need Applications in 2004, specifically the Edmonton-Calgary 500 kV and the Southwest Alberta Transmission Development Need Applications, were unanticipated.
- Categories such as office stationary, subscriptions, memberships, and bank charges experienced small increases compared to forecasts.
- The 2004 approved forecast of corporate recruitment costs included \$0.1 million for recruiting under the consulting line item. However, the 2004 recorded recruitment costs have been reclassified under the caption office costs due to the types of costs that were incurred. In addition to using consultants for specialized recruitment services, the AESO incurred general costs for job advertisements, travel and accommodations, and legal services. The 2004 recorded amount for recruitment was \$0.1 million.

#### **Line 65 Taxes**

The \$0.4 million in recoverable taxes recorded in 2004 relates to an adjustment for the 2003 federal and provincial taxes of the Transmission Administrator of Alberta, the for-profit predecessor organization to the AESO. Included in the 2003 financial statements of the AESO was an estimate for the 2003 taxes payable and this amount was \$0.4 million in excess of the taxes payable as determined through the filing of the 2003 tax returns in 2004.

The 2004 recorded costs for the remaining general and administrative costs did not vary significantly from the 2004 approved forecast.

#### **46.1.6 Capital (Line 70)**

Capital investment is required by the AESO primarily for the development of IT infrastructure necessary to support the transmission function, and also for furniture and equipment. Capital costs recorded in 2004 were \$5.2 million, which is \$1.9 million (or 58%) higher than the 2004 approved forecast.

The AESO acquired new office space in 2004 which resulted in leasehold improvements and new furniture purchases. In addition, minor leasehold improvements were made to the formerly occupied premises to ready the space for subtenants. The cost attributable to these changes was \$1.5 million, which was not included in the 2004 approved forecast and constitutes three-quarters of the 2004 variance. The relocation costs were required by the

amalgamation of AESO staff into one location in 2003, and were previously approved by AESO Board Members.

The remaining capital cost variance is attributable to the following capital projects:

- 5 • \$0.5 million below forecast cost of \$0.5 million, due to deferral of integration of billing and settlement systems to 2005;
- \$0.1 million below forecast cost of \$0.3 million, due to delay in implementation of common information model;
- 10 • \$0.3 million above forecast cost of \$0.2 million, due to expanded scope of customer and corporate service workflow project;
- \$0.4 million above forecast cost of \$0.1 million, due to NERC cyber security and high availability environment project, the latter component of which was not anticipated in the forecast;
- 15 • \$0.2 million above forecast cost of \$0.1 million, due to modification to the Energy Trading System and Dispatch Tool in conjunction with modifications to the Ancillary Services Market modifications;
- \$0.1 million below forecast cost of \$0.1 million, due to deferral of optimal power flow implementation to 2005;
- 20 • \$0.4 million in unforecast cost, due to unanticipated business efficiency initiatives to manage, automate, and streamline information, data, and business processes throughout the AESO;
- \$0.1 million in unforecast cost, due to unanticipated requirement for interconnection transfer capability posting project;
- 25 • \$0.2 million in unforecast cost, due to allocation of portion of \$4.3 million electronic load settlement initiative (e-LSI, since renamed to a compliance monitoring program) costs to transmission to reflect improvements to POD and system level metering processes and controls; and
- 30 • \$0.1 million under forecast cost of \$0.2 million, due to small variances in other projects and variances in a number of capital projects with individual budgets of less than \$50,000.

Additional detail on 2004 capital costs is available in section 3.2 of the AESO's 2006 General Tariff Application filed on January 31, 2005 and available on the AESO web site at [www.aeso.ca](http://www.aeso.ca) by following the path Tariff ► Previous Applications ► 2006 Tariff Application (Application No. 1363012).

**4**  
**6.2 2004 Revenue Variances**

40 Table 46-3 presents AESO revenue forecast to be collected from base rates in effect during 2004. The table also includes recorded revenue as collected through 2004 base rates, as well as variances between forecast and recorded revenues in both dollar amounts and as a percentage of forecast revenue. (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.)

A tariff was not specifically approved by the EUB for 2004 as the AESO 2004 revenue requirement did not receive EUB approval until December 2, 2004. Rates based on the 2004 revenue requirement accordingly did not become effective until January 1, 2005. The rates in place during 2004 were those approved as part of the AESO's 2003 tariff application, in EUB Decision 2003-077 to be effective December 1, 2003. The forecast revenue provided in

Table 4-3 is accordingly based on those 2003 rates.

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 2004 recorded base rates

**Table 4-3 2004 Base Rate Revenue Variances, \$ 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	226.6	227.5	0.9	0.4%
2	Operating Reserve	116.7	119.9	3.1	2.7%
3	Other System Support	2.3	2.2	(0.1)	(3.9%)
4	<b>Total DTS</b>	<b>345.6</b>	<b>349.6</b>	<b>3.9</b>	<b>1.1%</b>
<b>Supply Transmission Service</b>					
5	Interconnection	155.8	153.5	(2.3)	(1.5%)
6	Losses	177.1	138.4	(38.6)	(21.8%)
7	Operating Reserve	118.0	116.4	(1.7)	(1.4%)
8	<b>Total STS</b>	<b>450.9</b>	<b>408.3</b>	<b>(42.7)</b>	<b>(9.5%)</b>
<b>Total DTS and STS</b>					
9	Interconnection	382.4	381.0	(1.5)	(0.4%)
10	Losses	177.1	138.4	(38.6)	(21.8%)
11	Operating Reserve	234.8	236.2	1.5	0.6%
12	Other System Support	2.3	2.2	(0.1)	(3.9%)
13	<b>Total DTS and STS</b>	<b>796.5</b>	<b>757.8</b>	<b>(38.7)</b>	<b>(4.9%)</b>

Note: Numbers may not add due to rounding.

A tariff was not specifically approved by the AUC for 2004 as the AESO 2004 revenue requirement did not receive AUC approval until December 2, 2004. Rates based on the 2004 revenue requirement accordingly did not become effective until January 1, 2005. The rates in place during 2004 were those approved as part of the AESO's 2003 tariff application, in AUC Decision 2003-077 to be effective December 1, 2003. The forecast revenue provided in Table 6-3 is accordingly based on those 2003 rates.

5 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 2004 recorded base rates revenue in column (b) of Table ~~4-3~~ totalled ~~6-3~~ totalled \$757.8 million, which is \$38.7 million (or 5%) less than the 2004 forecast revenue of \$796.5 million.

10 This base rates revenue variance arises mainly from losses revenue of \$138.4 million, which is \$38.6 million (or 22%) less than the 2004 forecast revenue of \$177.1 million. Losses charges in the AESO's 2004 tariff were determined as a percentage of pool price, and the variance is primarily due to a combination of higher volumes in low pool price hours and lower volumes in high price hours as compared to forecast.

15 The base rate revenue variances for other DTS and STS rate components ranged up to  $\pm 4\%$  of forecast, which is considered small enough that specific variance explanations are not required.

#### 20 **4.3 — 2004 Deferral Account Balance**

25 ~~Costs and revenue variances through the year give rise to deferral account balances. The deferral account balances for 2004 are summarized in Table 4-4, and reflect the 2004 recorded costs and revenues provided in Tables 4-1 and 4-3 respectively. Table 4-3 also includes Deferral Account Adjustment Rider C, which collects or refunds revenue to align actual revenues with actual costs by rate and rate component.~~

~~Table 4-4~~ 2004 Deferral Account Summary, \$ 000 000

Line No.	Recorded Base Rate Revenue (a)	Recorded Costs (b)	Over (Under) Collection (c)=(a)+(b)	Rider C Collected (Refunded) (d)	Net Over (Under) Collection Variance		
					\$ (e)=(c)+(d)	% (f)=- (e)÷(b)	
<b>Demand Transmission Service</b>							
1	227.5	<del>(244.6)</del> <u>(243.9)</u>	<del>(17.1)</del> <u>(16.3)</u>	22.6	<del>5.5</del> <u>6.3</u>	2.26%	
2	119.9	<del>(61.9)</del> <u>(60.3)</u>	<del>58.0</del> <u>59.6</u>	(60.1)	<del>(2.1)</del> <u>(0.5)</u>	<del>(3.4)</del> <u>(0.9)</u> %	
3	2.2	(2.2)	(0.0)	0.2	0.1	6.85%	
4	349.6	<del>(308.7)</del> <u>(306.3)</u>	<del>40.9</del> <u>43.2</u>	(37.4)	<del>3.5</del> <u>9</u>	1.49%	
<b>Supply Transmission Service</b>							
5	153.5	<del>(177.0)</del> <u>(176.4)</u>	<del>(23.5)</del> <u>0</u>	28.3	<del>4.7</del> <u>5.3</u>	<del>2.7</del> <u>3.0</u> %	
6	138.4	<del>(142.2)</del> <u>(148.0)</u>	<del>(3.8)</del> <u>(9.6)</u>	(7.7)	<del>(11.5)</del> <u>(17.3)</u>	<del>(8.1)</del> <u>(11.7)</u> %	
7	116.4	<del>(61.9)</del> <u>(60.3)</u>	<del>54.5</del> <u>56.1</u>	(55.3)	<del>(0.8)</del>	<del>(1.3)</del> %	
8	408.3	<del>(381.1)</del> <u>(384.7)</u>	<del>27.2</del> <u>23.5</u>	(34.7)	<del>(7.6)</del> <u>(11.2)</u>	<del>(2.0)</del> <u>(9)</u> %	



	<b>Total DTS and STS</b>					
9	Interconnection	381.0	<del>(421.6)</del> <u>(420.3)</u>	<del>(40.6)</del> <u>(39.3)</u>	50.8	<del>10.2</del> <u>11.5</u> 2.47%
10	Losses	138.4	<del>(142.2)</del> <u>(148.0)</u>	<del>(3.8)</del> <u>(9.6)</u>	(7.7)	<del>(11.5)</del> <u>(17.3)</u> (8.111.7%)
11	Operating Reserve	236.2	<del>(123.8)</del> <u>(120.6)</u>	<del>112.5</del> <u>115.7</u>	(115.4)	<del>(2.9)</del> <u>0.3</u> (0.2.4%)
12	Other System Support	2.2	(2.2)	(0.0)	0.2	0.1 6.85%
13	<b>Total DTS and STS</b>	<b>757.8</b>	<del>(689.8)</del> <u>(691.1)</u>	<del>68.0</del> <u>66.8</u>	(72.1)	<del>(4.1)</del> <u>(5.3)</u> (0.68%)

Note: Numbers may not add due to rounding.

### 6.3 2004 Deferral Account Balance

Costs and revenue variances through the year give rise to deferral account balances. The deferral account balances for 2004 are summarized in Table 6-4, and reflect the 2004 recorded costs and revenues provided in Tables 6-1 and 6-3 respectively. Table 6-4 also includes Deferral Account Adjustment Rider C, which collects or refunds revenue to align actual revenues with actual costs by rate and rate component.

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 levels each quarter based on estimates of deferral account balances at the end of the quarter and forecast billing volumes for the quarter.

The total recorded revenue collected with respect to 2004 is therefore the sum of revenue collected through base rates as discussed in section 46.2, plus revenue collected or refunded through Rider C during 2004 and in the first quarter of 2005. The goal of Rider C is to provide total revenue which aligns more closely with total costs incurred than would be possible through the use of base rates only. Table 46-4 includes a portion of the Rider C amounts refunded or collected in the first quarter of 2005, reflecting that portion of the rider which refunded or collected the balance in the ~~DTS~~ deferral accounts that was estimated to remain at the end of 2004. The allocation between 2004 and 2005 of Rider C amounts charged or refunded in 2005 is reconciled in Appendix ~~NE-2~~ of this application.

In general, Rider C collections and refunds for 2004 maintained net deferral account balances at reasonable levels of less than ±7% of costs for all rate components except STS losses charges, which were undercollected by ~~8.1~~12% of costs. As explained in sections 46.1 and 46.2, loss costs and revenues varied from forecast due to a combination of higher volumes in low pool price hours and lower volumes in high price hours as compared to forecast. Recorded losses volumes were also somewhat less than forecast for 2004. Finally,



loss costs were increased as a result of the processing in 2008 of suspended TA Adjustments attributable to 2004.

5

Additional details on 2004 recorded revenues and costs 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 ~~7~~9 of this application.

## **57 2003 FINANCIAL RESULTS AND DEFERRAL ACCOUNT BALANCE**

5 The AESO filed a first reconciliation of its 2003 financial results and deferral account balance in its 2003 deferral account reconciliation application submitted to the EUBAUC on June 4, 2004. That reconciliation was revised in a refiling on December 14, 2004 pursuant to EUBAUC directions provided during the proceeding, and subsequently approved in EUBAUC Decision 2005-034 issued on April 19, 2005.

10 The AESO also committed during the proceeding to consult with stakeholders on the treatment of carryover adjustments which occurred after the cut-off date for a deferral account reconciliation. In accordance with conclusions reached during consultation on the deferral account reconciliation process (as discussed in Appendix A of this application), the 2003 deferral account has been reconciled a second time (and potentially will be reconciled a third time, depending on materiality of future adjustments). This section discusses the 2003 financial results and deferral account balance as determined for the 2003 second reconciliation.

### **57.1 2003 Deferral Account Second Reconciliation**

20 The 2003 deferral account first reconciliation included revenue and cost transactions that related to 2003 and prior years and that occurred:

- for transactions other than losses, from January 1, 2003, to January 31, 2004, and
- for transactions related to losses, from January 1, 2003, to August 31, 2004.

25 The 2003 second reconciliation includes revenue and cost transactions that relate to 2003 and that occurred from January 1, 2003, to July~~March~~ 31, 2007~~2008~~. These transactions establish the 2003 production month data for deferral account reconciliation purposes in this application.

30 As a result, the costs included in the 2003 second reconciliation differ from those included in the first reconciliation in two primary respects, which are summarized in Table 57-1.

35 (a) The first reconciliation included cost transactions that occurred from January 1, 2003, to January 31, 2004 (and, for losses, to August 31, 2004) and that related to **2003 and prior years**, rather than **solely to 2003**. In this application, the second reconciliation excludes transactions in the first reconciliation which related to years prior to 2003. Those prior-year transactions have instead been assigned to the relevant prior year, in accordance with the production month presentation discussed in section 2.2 of this application. The 2003 recorded costs reported in the first reconciliation ~~totalled~~totalled \$733.3 million, while the recorded costs reported in this second reconciliation for the same transactions after removal of the pre-2003 costs total \$732.4 million. The pre-2003 costs which were included in the first deferral account reconciliation for 2003 are presented in column (b) of Table 57-1.

45 ~~(b) — The first reconciliation included cost transactions that related to 2003 and that occurred up to January 31, 2004 for non-losses transactions and up to August 31,~~



~~2004 for losses-related transactions. This application includes additional transactions that relate to 2003 and that occurred from these dates up to July 31, 2007. The~~

Appendix M Comparison — 2003 Deferral Account  
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Table 57-1 Costs Included in 2003 First and Second Reconciliations, \$ 000 000

Line No.		Deferral Account Reconciliation (DAR) Recorded Costs				
		1st DAR (a)	Prior to 2003 (b)	2003-Only 1st DAR (c)=(a)+(b)	Post 1st DAR (d)	2nd DAR (e)=(c)+(d)
<b>WIRES</b>						
<b>TFO's Wires-Related Costs</b>						
1	AltaLink	136.2	(0.1)	136.1	14.7	150.8
2	ATCO Electric Ltd.	132.2	0.3	132.5	<del>14.8</del> 0	<del>144.3</del> 133.5
<del>23</del>	Foster Creek Substation	-	-	-	-	-
<del>34</del>	Isolated Generation	(5.7)	0.0	(5.7)	-	(5.7)
<del>45</del>	Subtotal ATCO Costs	126.5	0.3	126.8	<del>14.8</del> 0	<del>138.6</del> 127.8
<del>56</del>	Enmax Power Corporation	31.3	-	31.3	1.3	32.6
<del>67</del>	EPCOR Transmission Inc.	31.2	-	31.2	(1.9)	29.3
<del>78</del>	City of Lethbridge	4.3	-	4.3	-	4.3
<del>89</del>	TransAlta	2.8	-	2.8	-	2.8
<del>910</del>	City of Red Deer	1.8	-	1.8	-	1.8
<del>1011</del>	Aquila Networks (Farm)	2.5	(0.6)	1.9	-	1.9
<del>1112</del>	Unassigned Capital Additions	-	-	-	-	-
<del>1113</del>	Subtotal TFO Wires-Related Costs	336.6	(0.4)	336.2	<del>25.8</del> 15.0	<del>362.0</del> 351.2
<b>Non-Wires Costs</b>						
<del>1214</del>	Invitation to Bid on Credits (IBOC)	2.4	-	2.4	-	2.4
<del>1315</del>	Location Based Credit Standing Offer (LBC SO)	4.2	(0.1)	4.1	0.3	4.4
<del>1416</del>	Subtotal IBOC/LBC SO Costs	6.6	(0.1)	6.5	0.3	6.8
<del>1517</del>	Prior Period Adjustment	(0.3)	0.3	(0.0)	-	(0.0)
<del>1518</del>	TOTAL WIRES COSTS	342.9	(0.2)	342.7	<del>26.1</del> 15.3	<del>368.8</del> 358.0
<b>ANCILLARY SERVICES</b>						
<b>Operating Reserves</b>						
<b>Active</b>						
<del>1619</del>	Regulating	42.2	-	42.2	-	42.2
<del>1720</del>	Spinning	45.5	(0.0)	45.5	<del>-0.0</del>	45.5
<del>1821</del>	Supplemental	8.4	-	8.4	0.0	8.4
<del>1922</del>	Subtotal Active Reserves	96.1	(0.0)	96.1	0.0	96.2
<b>Standby</b>						
<del>2023</del>	Regulating	9.8	-	9.8	-	9.8
<del>2124</del>	Spinning	12.2	0.0	12.2	<del>(0.0)</del>	12.2
<del>2225</del>	Supplemental	3.3	-	3.3	0.0	3.3
<del>2326</del>	Subtotal Standby Reserves	25.3	0.0	25.3	0.0	25.3
<del>2427</del>	Trading Fees & Other Related Charges	(1.4)	0.2	(1.3)	(0.0)	(1.3)
<del>2528</del>	Subtotal Operating Reserves	120.0	0.2	120.2	(0.0)	120.2

Table 57-1 Costs Included in 2003 First and Second Reconciliations, \$ 000 000 (continued)

Line No.		Deferral Account Reconciliation (DAR) Recorded Costs				
		1st DAR (a)	Prior to 2003 (b)	2003-Only DAR (c)=(a)+(b)	Post 1st DAR (d)	2nd DAR (e)=(c)+(d)
<b>Other Ancillary Services</b>						
2629	Generator Remedial Action Schemes (RAS)	0.4	-	0.4	-	0.4
2730	Black Start	1.0	-	1.0	-	1.0
2831	Transmission Must Run (TMR)	45.2	(1.1)	44.1	(0.3)	43.8
2932	Under Frequency Mitigation	6.5	-	6.5	-	6.5
3033	Hydro Motoring	2.8	-	2.8	-	2.8
3434	Fort Saskatchewan Load Shed	-	-	-	-	-
3435	<b>Subtotal Other Ancillary Services</b>	<b>55.8</b>	<b>(1.1)</b>	<b>54.8</b>	<b>(0.3)</b>	<b>54.5</b>
<b>Poplar Hill/ILRAS</b>						
3236	Poplar Hill	2.5	(0.3)	2.2	-	2.2
3337	Interruptible Load Remedial Action (ILRAS)	0.1	0.4	0.5	(0.0)	0.5
3438	<b>Subtotal Poplar Hill/ILRAS</b>	<b>2.6</b>	<b>0.1</b>	<b>2.7</b>	<b>(0.0)</b>	<b>2.7</b>
3539	<b>TOTAL ANCILLARY SERVICES</b>	<b>178.5</b>	<b>(0.8)</b>	<b>177.7</b>	<b>(0.3)</b>	<b>177.4</b>
<b>LOSSES</b>						
3640	Pool Payment	173.2	0.2	173.3	(16.6)(17.1)	156.8-2
3741	<b>TOTAL LOSSES COSTS</b>	<b>173.2</b>	<b>0.2</b>	<b>173.3</b>	<b>(16.6)(17.1)</b>	<b>156.8-2</b>
<b>OTHER INDUSTRY COSTS</b>						
3842	External Regulatory Costs	7.9	(0.2)	7.7	-(0.0)	7.7
3943	Western Electricity Coordination Council (WECC)	0.7	-	0.7	-	0.7
4044	Share of EUBAUC Overhead	0.8	-	0.8	-	0.8
4445	<b>TOTAL OTHER INDUSTRY COSTS</b>	<b>9.4</b>	<b>(0.2)</b>	<b>9.3</b>	<b>-(0.0)</b>	<b>9.3</b>
<b>GENERAL AND ADMINISTRATIVE COSTS</b>						
<b>Administrative Costs</b>						
4246	Staff and Benefits	12.7	-	12.7	-	12.7
4347	Interconnection Fees (Offset)	(0.3)	-	(0.3)	-	(0.3)
4448	<b>Subtotal Staff &amp; Benefits</b>	<b>12.4</b>	<b>-</b>	<b>12.4</b>	<b>-</b>	<b>12.4</b>
4549	Consultants	4.3	-	4.3	-	4.3
4650	Interconnection Fees (Offset)	(0.3)	-	(0.3)	-	(0.3)
4751	<b>Subtotal Consultants</b>	<b>4.0</b>	<b>-</b>	<b>4.0</b>	<b>-</b>	<b>4.0</b>
4852	Board Members Fees	0.2	-	0.2	-	0.2
4953	Travel and Training	0.6	-	0.6	-	0.6
5054	Legal	1.0	-	1.0	-	1.0
5155	Accounting and Tax Advice	0.2	-	0.2	-	0.2
5256	Rent	1.0	-	1.0	-	1.0
5357	Insurance	0.3	-	0.3	-	0.3
5458	Other Administrative Costs	1.9	-	1.9	-	1.9
5559	Negotiated Settlement Reduction	-	-	-	-	-
5660	<b>Total Administrative Costs</b>	<b>21.6</b>	<b>-</b>	<b>21.6</b>	<b>-</b>	<b>21.6</b>

Table 57-1 Costs Included in 2003 First and Second Reconciliations, \$ 000 000 (continued)

Line No.	Deferral Account Reconciliation (DAR) Recorded Costs				
	1st DAR (a)	Prior to 2003 (b)	2003-Only DAR (c)=(a)+(b)	Post 1st DAR (d)	2nd DAR (e)=(c)+(d)
<b>General Costs</b>					
5761	Interest	-	-	-(1.7)	-(1.7)
5862	Amortization and Depreciation	1.2	-	1.2	1.2
5963	Tariff Deficiency Correction Regulation Fee	4.9	-	4.9	4.9
6064	ISO Transition Costs	1.2	-	1.2	1.2
6465	Taxes	0.5	-	0.5	0.5
6266	Total General Costs	7.8	-	7.8	7.8-6.1
6367	Total General & Administrative Costs	29.4	-	29.4	29.4-27.7
<b>System Controller Shared Costs</b>					
6468	System Controller Shared Costs	-	-	-	-
6569	Total G&A and System Controller Costs	29.4	-	29.4	29.4-27.7
6670	Total G&A and Other Industry Costs	38.9-8	(0.2)	38.7	38.7-37.0
6771	TOTAL REVENUE REQUIREMENT	733.3	(1.0)	732.4	741.6-728.7
6872	CAPITAL	2.2	-	2.2	2.2

Notes: Numbers may not add due to rounding

5 (b) The first reconciliation included cost transactions that related to 2003 and that occurred up to **January 31, 2004** for non-losses transactions and up to **August 31, 2004** for losses-related transactions. This application includes additional transactions that relate to 2003 and that occurred from those dates up to **March 31, 2008**. The inclusion of these additional transactions ~~increases~~ ~~further~~ ~~decreases~~ the 2003 recorded costs to \$~~741.6~~~~728.7~~ million. The 2003 costs which occurred after the first deferral account reconciliation are presented in column (d) of Table 57-1.

15 The net result of the exclusion of prior-year transactions and the inclusion of later transactions is \$~~741.6~~~~728.7~~ million in costs and \$730.7 million in customer revenues (including Rider C collections and refunds) being attributed to 2003.

20 Revenue and cost transactions that occurred from January 1, 2003, to ~~July~~~~March~~ 31, ~~2007~~~~2008~~ may relate, in whole or in part, to years other than 2003. In such instance 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 2003 and other years for transactions which occurred from 2003 to 2007 is provided in Appendix E-1 of this application.

5 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 and 4 relating to 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 2003.

## 7.2 2003 Cost Adjustments After First Reconciliation

10 The AESO's forecast costs for 2003 were approved in EUBAUC Decision 2003-077 issued on November 4, 2003. Variances of recorded costs from that approved forecast were explained in the first reconciliation of the 2003 deferral account (for those transactions included in that first reconciliation) and approved in EUBAUC Decision 2005-034 on the AESO's 2003 Deferral Account Reconciliation. No further discussion of those variances is provided in this application. Only cost adjustments which arise from transactions that occurred after the first reconciliation are discussed in this application.

Specifically, the 2003 cost adjustments which occurred after the first reconciliation and which are included in this second deferral account reconciliation are those transactions that:

- relate to 2003,
- occurred after the cut-off date for data included in the 2003 first reconciliation, and
- occurred up to July~~March~~ 31, 2007~~2008~~.

25 These 2003 cost adjustments, together with the original 2003-related transactions which were included in the first reconciliation, establish the 2003 production year data for deferral account reconciliation purposes in this application.

Table 57-2 presents the following information for 2003:

- column (b) contains 2003 recorded costs as approved in EUBAUC Decision 2005-034, but only those amounts specifically attributed to 2003 as discussed in the preceding section;
- column (c) contains additional amounts attributed to 2003 which occurred after the cut-off date for transactions included in the first reconciliation;
- column (d) contains the 2003 recorded costs included in this application, which is the sum of the previously-approved amounts in column (b) and the additional amounts in column (c); and
- column (e) provides the 2003 additional amounts from column (c) as a percentage of the recorded costs from the first reconciliation from column (b).

40 As already discussed in section 3.1 and 4.1—the previous sections of this application, variances arise due to a number of factors, including finalization of TFO costs through EUBAUC 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 reconciliations for 2006, 2005, and 2004, in sections 34.1, 5.1, and 6.1 and 4.1 of this application respectively, the AESO considered a line item variance to be significant



when it exceeded  $\pm\$3.0$  million, or, if it was smaller than  $\pm\$3.0$  million, when it was both at least  $\pm\$0.3$  million and at least  $\pm 10\%$  of the approved line item amount.

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~~In this second reconciliation for 2003, 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. 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  $\pm\$3.0$  million threshold, together they may exceed it.~~

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~~Therefore, in Table 5-2, the AESO considers a line item variance between the first reconciliation recorded costs and the second reconciliation recorded costs to be significant when it exceeds  $\pm\$1.5$  million, which represents approximately 5% of the \$29.4 million general and administrative costs component of the 2003 first reconciliation recorded costs. A line item variance smaller than  $\pm\$1.5$  million is also considered significant when it is both~~

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**Table 57-2 2003 First and Second Deferral Account Reconciliation Variances, \$ 000 \$ 000 000**

Line No.	Approved Forecast	Recorded Costs and Adjustments			Adjustments	
		2003-Only 1st DAR <sup>+1</sup>	Post 1st DAR <sup>+1</sup>	2nd DAR <sup>+1</sup>	Over (Under) %	
	(a)	(b)	(c)	(d)=(b)+(c)	(e)=(c)÷(b)	
<b>WIRES</b>						
<b>TFO's Wires-Related Costs</b>						
1	AltaLink	133.3	136.1	14.7	150.8	10.8%
2	ATCO Electric Ltd.	132.6	132.5	<del>14.8</del> 0	<del>144.3</del> 133.5	<del>8.90</del> 7%
3	Foster Creek Substation	1.4	-	-	-	-
4	Isolated Generation	(6.1)	(5.7)	-	(5.7)	-
5	Subtotal ATCO Costs	127.9	126.8	<del>14.8</del> 0	<del>138.6</del> 127.8	<del>9.30</del> 8%
6	Enmax Power Corporation	34.4	31.3	1.3	32.6	4.2%
7	EPCOR Transmission Inc.	34.0	31.2	(1.9)	29.3	(6.1%)
8	City of Lethbridge	2.8	4.3	-	4.3	-
9	TransAlta	2.7	2.8	-	2.8	-
10	City of Red Deer	1.8	1.8	-	1.8	-
11	Aquila Networks (Farm)	1.9	1.9	-	1.9	-
12	Unassigned Capital Additions	1.1	-	-	-	-
13	Subtotal TFO Wires-Related Costs	339.9	336.2	<del>25.8</del> 15.0	<del>362.0</del> 351.2	<del>7.74</del> 5%
<b>Non-Wires Costs</b>						
14	Invitation to Bid on Credits (IBOC)	2.7	2.4	-	2.4	-
15	Location Based Credit Standing Offer (LBC SO)	3.9	4.1	0.3	4.4	7.2%
16	Subtotal IBOC/LBC SO Costs	6.6	6.5	0.3	6.8	4.5%
17	Prior Period Adjustment	-	(0.0)	-	(0.0)	-
18	<b>TOTAL WIRES COSTS</b>	346.5	342.7	<del>26.1</del> 15.3	<del>368.8</del> 358.0	<del>7.64</del> 5%
<b>ANCILLARY SERVICES</b>						
<b>Operating Reserves</b>						
<b>Active</b>						
19	Regulating	48.2	42.2	-	42.2	-
20	Spinning	49.3	45.5	<del>0.0</del>	45.5	<del>0.0</del> %
21	Supplemental	24.7	8.4	0.0	8.4	0.4%
22	Subtotal Active Reserves	122.2	96.1	0.0	96.2	0.0%
<b>Standby</b>						
23	Regulating	22.1	9.8	-	9.8	-
24	Spinning	19.1	12.2	<del>(0.0)</del>	12.2	<del>(0.0)</del> %
25	Supplemental	3.6	3.3	0.0	3.3	0.1%
26	Subtotal Standby Reserves	44.8	25.3	0.0	25.3	0.0%
27	Trading Fees & Other Related Charges	-	(1.3)	(0.0)	(1.3)	2.9%
28	Subtotal Operating Reserves	167.0	120.2	(0.0)	120.2	(0.0%)

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Table 5Z-2 2003 First and Second Deferral Account Reconciliation Variances, \$ 000 000 (continued)

Line No.	Approved Forecast	Recorded Costs and Adjustments			Adjustments	
		2003-Only 1st DAR <sup>+1</sup>	Post 1st DAR <sup>+1</sup>	2nd DAR <sup>+1</sup>	Over (Under) %	
	(a)	(b)	(c)	(d)=(b)+(c)	(e)=(c)÷(b)	
<b>Other Ancillary Services</b>						
29	Generator Remedial Action Schemes (RAS)	0.4	0.4	-	0.4	-
30	Black Start	2.2	1.0	-	1.0	-
31	Transmission Must Run (TMR)	26.1	44.1	(0.3)	43.8	(0.6%)
32	Under Frequency Mitigation	5.2	6.5	-	6.5	-
33	Hydro Motoring	4.2	2.8	-	2.8	-
34	Fort Saskatchewan Load Shed	0.9	-	-	-	-
35	<b>Subtotal Other Ancillary Services</b>	<b>39.0</b>	<b>54.8</b>	<b>(0.3)</b>	<b>54.5</b>	<b>(0.5%)</b>
<b>Poplar Hill/ILRAS</b>						
36	Poplar Hill	1.9	2.2	-	2.2	-
37	Interruptible Load Remedial Action (ILRAS)	0.5	0.5	(0.0)	0.5	(9.1%)
38	<b>Subtotal Poplar Hill/ILRAS</b>	<b>2.4</b>	<b>2.7</b>	<b>(0.0)</b>	<b>2.7</b>	<b>(1.7%)</b>
39	<b>TOTAL ANCILLARY SERVICES</b>	<b>208.4</b>	<b>177.7</b>	<b>(0.3)</b>	<b>177.4</b>	<b>(0.2%)</b>
<b>LOSSES</b>						
40	Pool Payment	142.7	173.3	<del>(16.6)</del> (17.1)	156.8 <del>2</del>	(9.69%)
41	<b>TOTAL LOSSES COSTS</b>	<b>142.7</b>	<b>173.3</b>	<b>(16.6)</b> (17.1)	<b>156.8<del>2</del></b>	<b>(9.69%)</b>
<b>OTHER INDUSTRY COSTS</b>						
42	External Regulatory Costs	9.8	7.7	<del>-(0.0)</del>	7.7	<del>-(0.2%)</del>
43	Western Electricity Coordination Council (WECC)	1.0	0.7	-	0.7	-
44	Share of <del>EUBAUC</del> Overhead	1.6	0.8	-	0.8	-
45	<b>TOTAL OTHER INDUSTRY COSTS</b>	<b>12.4</b>	<b>9.3</b>	<b><del>-(0.0)</del></b>	<b>9.3</b>	<b><del>-(0.1%)</del></b>
<b>GENERAL AND ADMINISTRATIVE COSTS</b>						
<b>Administrative Costs</b>						
46	Staff and Benefits	8.3	12.7	-	12.7	-
47	Interconnection Fees (Offset)	(0.2)	(0.3)	-	(0.3)	-
48	<b>Subtotal Staff &amp; Benefits</b>	<b>8.1</b>	<b>12.4</b>	<b>-</b>	<b>12.4</b>	<b>-</b>
49	Consultants	2.5	4.3	-	4.3	-
50	Interconnection Fees (Offset)	(0.3)	(0.3)	-	(0.3)	-
51	<b>Subtotal Consultants</b>	<b>2.2</b>	<b>4.0</b>	<b>-</b>	<b>4.0</b>	<b>-</b>
52	Board Members Fees	0.1	0.2	-	0.2	-
53	Travel and Training	0.7	0.6	-	0.6	-
54	Legal	0.4	1.0	-	1.0	-
55	Accounting and Tax Advice	0.1	0.2	-	0.2	-
56	Rent	0.7	1.0	-	1.0	-
57	<del>Insurance</del>	<del>0.3</del>	<del>0.3</del>	<del>-</del>	<del>0.3</del>	<del>-</del>
57	Insurance	0.3	0.3	-	0.3	-
58	Other Administrative Costs	0.7	1.9	-	1.9	-
59	Negotiated Settlement Reduction	(0.4)	-	-	-	-
60	<b>Total Administrative Costs</b>	<b>12.9</b>	<b>21.6</b>	<b>-</b>	<b>21.6</b>	<b>-</b>

Table 57-2 2003 First and Second Deferral Account Reconciliation Variances, \$ 000 000 (continued)

Line No.	Description	Recorded Costs and Adjustments			Adjustments	
		Approved Forecast (a)	2003-Only 1st DAR <sup>+1</sup> (b)	Post 1st DAR <sup>+1</sup> (c)	2nd DAR <sup>+1</sup> (d)=(b)+(c)	Over (Under) % (e)=(c)÷(b)
<b>General Costs</b>						
61	Interest	0.1	-	-(1.7)	-(1.7)	-
62	Amortization and Depreciation	1.5	1.2	-	1.2	-
63	Tariff Deficiency Correction Regulation Fee	4.9	4.9	-	4.9	-
64	ISO Transition Costs	1.2	1.2	-	1.2	-
65	Taxes	-	0.5	-	0.5	-
66	<b>Total General Costs</b>	<b>7.7</b>	<b>7.8</b>	<b>-(1.7)</b>	<b>7.8-6.1</b>	<b>-(21.8%)</b>
67	<b>Total General &amp; Administrative Costs</b>	<b>20.6</b>	<b>29.4</b>	<b>-(1.7)</b>	<b>29.4-27.7</b>	<b>-(5.8%)</b>
<b>System Controller Shared Costs</b>						
68	System Controller Shared Costs	3.6	-	-	-	-
69	<b>Total G&amp;A and System Controller Costs</b>	<b>3.6-24.2</b>	<b>-29.4</b>	<b>-(1.7)</b>	<b>-27.7</b>	<b>-(5.8%)</b>
70	<b>Total G&amp;A and Other Industry Costs</b>	<b>36.6</b>	<b>38.7</b>	<b>-(1.7)</b>	<b>38.7-37.0</b>	<b>-(4.4%)</b>
71	<b>TOTAL REVENUE REQUIREMENT</b>	<b>734.2</b>	<b>732.4</b>	<b>9.2-(3.8)</b>	<b>741.6</b> <b>728.7</b>	<b>1.3%-(0.5%)</b>
72	<b>CAPITAL</b>	<b>1.8</b>	<b>2.2</b>	<b>-</b>	<b>2.2</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

5 In this second reconciliation for 2003, 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. 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 ±\$3.0 million threshold, together they may exceed it.

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15 Therefore, in Table 7-2, the AESO considers a line item variance between the first reconciliation recorded costs and the second reconciliation recorded costs to be significant when it exceeds ±\$1.5 million, which represents approximately 5% of the \$29.4 million general and administrative costs component of the 2003 first reconciliation recorded costs. A line item variance smaller than ±\$1.5 million is also considered significant when it is both at least ±\$0.15 million and at least ±5% of the first reconciliation recorded costs line item amount. The ±\$0.15 million threshold represents approximately 0.5% of the \$29.4 million general and administrative costs component of the first reconciliation recorded costs, while

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the AESO considers  $\pm 5\%$  to be a reasonable threshold below which specific variance explanations are not required.

Variances exceeding these thresholds are shaded in Table 57-2, with explanations provided by line number in the following discussion. Where variances were either less than  $\pm \$0.15$  million or less than  $\pm 5\%$  (except where such variance is  $\pm \$1.5$  million or greater) explanations are not provided, as such variances are considered small enough that specific variance explanations are not required.

### 57.2.1 Wires Costs

The first reconciliation recorded costs for TFO wires was based on actual billings by the TFOs to the AESO for 2003 under interim or final approved tariffs at the time of the AESO's 2003 deferral account first reconciliation. The second reconciliation recorded cost was similarly based on actual billings by the TFOs to the AESO but under final 2003 tariffs approved for all TFOs.

#### Line 1 AltaLink

The second reconciliation recorded cost for AltaLink wires was \$150.8 million, which is \$14.7 million (or 11%) more than the first reconciliation recorded cost of \$136.1 million. The first reconciliation recorded cost reflects EUBAUC Order U2003-132 which approved AltaLink's 2003 Interim TFO Tariff (issued June 17, 2003). The second reconciliation recorded cost reflects EUBAUC Decision 2004-028 which approved AltaLink's and TransAlta's Final Transmission Tariff for 2003 (issued March 23, 2004). The variance results from the difference between the interim and final tariffs approved by the EUBAUC.

#### Line 2 ATCO Electric

Although not resulting in a significant variance from the first reconciliation recorded cost for 2005, this deferral account reconciliation includes several adjustments to ATCO Electric costs which occurred after the first reconciliation.

The second reconciliation recorded cost for ATCO Electric transmission wires was ~~\$144.3~~133.5 million, which is ~~\$14.8.0~~ million (or ~~90.7~~90.7%) more than the first reconciliation recorded cost of \$132.5 million. The first reconciliation recorded cost reflects EUBAUC Decision U2002-108 which approved ATCO Electric's 2003 Interim TFO Tariff (issued December 11, 2002). The second reconciliation recorded cost reflects ~~EUB~~AUC:

- AUC Decision 2004-016 which approved ATCO Electric's General Tariff Application Refiling for 2003 (issued February 24, 2004) ~~and~~;
- AUC Decision 2004-104 which approved ATCO Electric's 2003 Deferral Account Balances (issued December 7, 2004) ~~); and~~
- AUC Decision 2007-104 on ATCO Electric's 2007-2008 General Tariff Application Refiling which approved a refund of future income taxes that ATCO Electric had collected from customers, of which \$10.8 million was applied as a refund to 2003 as discussed in section 3.1.1 of this application.

The variance results from the difference between the interim tariff and the final tariff and ~~deferral account other adjustment~~ amounts approved by the EUBAUC.

**Line 7 EPCOR Transmission Inc.**

The second reconciliation recorded cost for EPCOR Transmission wires was \$29.3 million, which is \$1.9 million (or 6%) less than the first reconciliation recorded cost of \$31.2 million. The variance reflects the \$1.9 million difference between EPCOR's 2003 interim and final transmission revenue requirements, which the **EUBAUC** ordered to be refunded to the AESO in Decision 2004-018 dated February 26, 2004 regarding EPCOR's 2003-2004 TFO Tariff.

**Line 15 Location Based Credit Standing Offer (LBC SO)**

The LBC SO program provides increased system security, whereby the AESO retains dispatch rights to location-specific generation in return for location-based credits made up of fixed and variable payments. The 2003 second reconciliation recorded costs for LBC SO were \$4.4 million, which is \$0.3 million (or 7%) more than the first reconciliation recorded costs of \$4.1 million due to a refund in 2004 of an LBC SO amount relating to 2003.

**57.2.2 Losses (Line 40)**

Losses are the energy lost on the transmission system when power is transmitted from suppliers to loads. Losses are the residual of the metered generation plus scheduled imports less scheduled exports and less metered loads. Losses can vary significantly and are influenced by many factors, including load level, generation dispatch and the level of imports or exports.

The second reconciliation recorded cost for losses was \$156.82 million, which is ~~\$16.6~~17.1 million (or 10%) less than the first reconciliation recorded cost of \$173.3 million. The variance is primarily due to the 2003 portion of a one-time adjustment to energy market settlement data.

The adjustment, which relates to 2001-2003 losses, was quantified as \$27.5 million in the AESO's 2005-2006 General Tariff Application proceeding. The amount of the adjustment has since been updated to \$24.2 million, as noted in the AESO's Deferral Account Summary for May 2005. Consistent with the treatment of material adjustments discussed in section A-5 of the stakeholder consultation conclusions provided in Appendix A of this application, the adjustment is included in the second reconciliation of the 2003 deferral account in this application.

The losses adjustment is a reduction to costs for a one-time adjustment related to a meter reading issue that ultimately resulted in a restatement of proprietary meter data of a specific customer over the years 2001, 2002, and 2003. This one time adjustment impacted the value of system losses in all three years. The portions of the adjustments related to each of these years are as follows:

- 2003: \$11.1 million
- 2002: \$13.0 million
- 2001: \$ 0.1 million
- Total: \$24.2 million

Each year's portion of this adjustment has been reconciled and allocated in accordance with the process for that year, as described in section A-5 and A-6 of Appendix A of this application. The \$11.1 million amount is included in the reconciliation and allocation for 2003, and the \$13.0 million and \$0.1 million amounts are included in the allocation for 2001 and 2002 discussed in section 6 of this application.

In addition to the \$11.1 million portion of the adjustment discussed above which is related to 2003, ~~two~~ other adjustments to energy market settlement data also occurred that affected 2003 losses. A \$3.8 million adjustment in September 2004 and a \$1.4 million adjustment in October 2004 both related to 2003, and a \$0.5 million refund arising from suspended TA Adjustments was attributed to 2003 as discussed in section 5.1.3 of this application. These amounts, together with several miscellaneous smaller adjustments, comprise the ~~\$16.6~~17.1 million variance in 2003 losses since the first 2003 deferral account reconciliation.

### 7.2.3 General and Administrative Costs

The second reconciliation recorded general and administrative costs were \$27.7 million, which is \$1.7 million (6%) less than the first reconciliation recorded costs of \$29.4 million, due to the recognition and redistribution of interest in this application.

#### Line 61 Interest

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, offset in 2003 by interest earned on transmission customer security deposits and other amounts; and
- amounts reflecting the recognition of interest on deferral account balances and its redistribution between production months to allow the appropriate allocation of costs under the extraordinary circumstances of this deferral account reconciliation application as detailed in section 2.3.

The second reconciliation recorded cost for interest was \$1.7 million credit, which is \$1.7 million less than the first reconciliation recorded cost of \$0.0 million. The \$1.7 million credit for recorded interest expense, and the resulting variance between second and first reconciliation recorded costs, is wholly due to the recognition and redistribution of interest discussed above to account for the extraordinary circumstances of this application.

The second reconciliation recorded costs for the AESO's remaining revenue requirement line items did not vary significantly from the first reconciliation recorded costs.

### 57.3 2003 Revenue Adjustments After First Reconciliation

Table 57-3 presents AESO revenue collected from base rates and Deferral Account Adjustment Rider C during 2003 and the first quarter of 2004, and as a result of the 2003 first deferral account reconciliation approved in EUBAUC Decision 2005-034. The table also provides 2003 revenue collected to July~~March~~ 31, 2007~~2008~~ which includes adjustments occurring after the first deferral account reconciliation, as well as variances between



revenue reported in the first reconciliation and in this second reconciliation, in both dollar amounts and as a percentage of first reconciliation revenue.

- 5 On an annual basis, transmission revenue depends on approved transmission tariff rates (including both base rates and Rider C), pool price, and billed volumes of demand and energy. Variances arise due to unanticipated changes to billing volumes and pool price. The second reconciliation recorded revenue in column (b) of Table 57-3 totalled \$730.7 million,

**Table 7-3** 2003 Recorded Revenue Variances, \$ 000 000

Line No.	First Reconciliation (a)	Second Reconciliation (b)	Variance Over (Under)		
			\$ (c)=(b)-(a)	% (d)=(c)÷(a)	
<b>Demand Transmission Service</b>					
1	Interconnection	221.4	219.5	(1.9)	(0.9%)
2	Operating Reserve	87.9	88.0	0.1	0.1%
3	Other System Support	2.6	2.6	(0.0)	(1.8%)
4	<b>Total DTS</b>	<b>311.9</b>	<b>310.1</b>	<b>(1.8)</b>	<b>(0.6%)</b>
<b>Supply Transmission Service</b>					
5	Interconnection	160.3	158.4	(1.9)	(1.2%)
6	Losses	173.2	174.5	1.3	0.8%
7	Operating Reserve	87.9	87.6	(0.3)	(0.3%)
8	<b>Total STS</b>	<b>421.4</b>	<b>420.6</b>	<b>(0.8)</b>	<b>(0.2%)</b>
<b>Total DTS and STS</b>					
9	Interconnection	381.7	377.9	(3.8)	(1.0%)
10	Losses	173.2	174.5	1.3	0.8%
11	Operating Reserve	175.8	175.7	(0.2)	(0.1%)
12	Other System Support	2.6	2.6	(0.0)	(1.8%)
13	<b>Total DTS and STS</b>	<b>733.3</b>	<b>730.7</b>	<b>(2.7)</b>	<b>(0.4%)</b>

Note: Numbers may not add due to rounding.

~~second reconciliation recorded revenue in column (b) of Table 5-3 totaled \$730.7 million,~~ which is \$2.7 million (or 0.4%) less than the first reconciliation recorded revenue of \$733.3 million.

Variances arising from revenue adjustments to DTS and STS rate components after the first deferral account reconciliation ranged within  $\pm 2\%$  of first reconciliation amounts, which is considered small enough that specific variance explanations are not required.

#### **57.4 2003 Deferral Account Balance**

Costs and revenue variances attributed to a year give rise to deferral account balances. The deferral account balances for the 2003 second reconciliation are summarized in Table 57-4, and reflect the 2003 second reconciliation costs and revenues provided in Table 57-2 and 57-3 respectively.

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 2003 tariff through Working Capital Deficiency/Surplus Rider B and Deferral Account Adjustment Rider C. The AESO did not invoke Rider B during 2003, 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 the quarter and forecast billing volumes for the

Table 57-4 2003 Deferral Account Summary, \$ 000 000

Line No.	Recorded Revenue (a)	Recorded Costs (b)	Net Over (Under) Collection Variance	
			\$ (c)=(a)+(b)	% (d)=- (c)÷(b)
<b>Demand Transmission Service</b>				
1	219.5	<del>(236.5)</del> (231.2)	<del>(17.1)</del> (11.8)	<del>(7.25.1)</del> %
2	88.0	<del>(87.4)</del> 3	0.7	0.8%
3	2.6	<del>(2.5)</del>	0.1	<del>4.53.7</del> %
4	310.1	<del>(326.4)</del> (321.1)	<del>(16.3)</del> (11.0)	<del>(5.03.4)</del> %
<b>Supply Transmission Service</b>				
5	158.4	<del>(171.2)</del> (167.3)	<del>(12.7)</del> (8.9)	<del>(7.45.3)</del> %
6	174.5	<del>(156.8)</del> (152.9)	<del>17.8</del> 21.6	<del>11.314.2</del> %
7	87.6	<del>(87.4)</del> 3	0.3	0.3%
8	420.6	<del>(415.3)</del> (407.5)	<del>5.3</del> 13.0	<del>1.3.2</del> %
<b>Total DTS and STS</b>				
9	377.9	<del>(407.7)</del> (398.5)	<del>(29.8)</del> (20.7)	<del>(7.35.2)</del> %
10	174.5	<del>(156.8)</del> (152.9)	<del>17.8</del> 21.6	<del>11.314.2</del> %
11	175.7	<del>(174.7)</del>	1.0	0.6%
12	2.6	<del>(2.5)</del>	0.1	<del>4.53.7</del> %
13	730.7	<del>(741.6)</del> (728.7)	<del>(112.0)</del>	<del>(1.5%)</del> 0.3%

Note: Numbers may not add due to rounding.

5 quarter. Rider C charges and refunds were included in the 2003 second reconciliation revenue provided in Table 57-4.

10 The first reconciliation of the 2003 deferral account restored all deferral account balances to zero based on the transactions included in that reconciliation, as illustrated in Table 2.3-5 in section 2.34 of this application. However, this second reconciliation includes some significant adjustments to costs that occurred after the first reconciliation of the 2003 deferral account, as discussed in section 57.2. Adjustments to revenues, on the other hand, have been reasonably small, as discussed in section 57.3. This second reconciliation therefore includes some relatively large deferral account components, primarily reflecting the adjustments to costs that have occurred since the first reconciliation.

15 The interconnection charges deferral account balance has increased to an undercollection of \$29.820.7 million (or 75% of recorded costs), primarily due to adjustments resulting from EUBAUC decisions on final TFO tariffs for AltaLink, ~~ATCO Electric~~, and EPCOR Transmission as discussed in ~~section 5~~section 7.2.1.

20 The losses deferral account balance has decreased to an overcollection of \$17.821.6 million (or 4414% of recorded costs), primarily due to the 2003 ~~portion~~portions of a one-time ~~adjustment~~adjustments to energy market settlement data as discussed in section 57.2.2.



5

Deferral account balances for operating reserve and for other system support have not changed significantly from the first reconciliation. The impact of all 2003 cost and revenue adjustments is a deferral account net balance ~~increased~~decrease to an undercollection of \$~~112~~142.0 million (or ~~4.50~~4.50.3% of recorded costs), compared to the zero balance based on transactions included in the first reconciliation.

10

Additional details on 2003 cost and revenue adjustments that occurred after the first reconciliation are provided in Appendices B through G of this application. The allocation of the 2003 net deferral account balances to customers is discussed in section ~~7~~79 of this application.

## **68 PRE-2003 DEFERRAL ACCOUNT ADJUSTMENTS**

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 pre-2003 tariffs through Working Capital Deficiency/Surplus Rider B and Deferral Account Adjustment Rider C. The AESO determined deferral account rider charges and refunds in accordance with the riders' approved purpose to restore deferral account balances to zero. The AESO set rider rates based on estimates of deferral account balances and forecast billing volumes. Additional charges and refunds relating to deferral account outstanding balances resulted after deferral account reconciliations were submitted to and approved by the EUBAUC.

However, cost and revenue adjustments relating to a deferral account year can continue to occur after a deferral account reconciliation is submitted and approved. Section 57 of this application discussed such adjustments relating to 2003. Adjustments relating to prior years are addressed in this section of the application.

Adjustment transactions included in this application have affected production month and production year data for 1999, 2000, 2001, and 2002. Specifically, the adjustment transactions which relate to the years 1999 to 2002 include:

- transactions that occurred from January 1, 2003 to January 31, 2004 (and, for losses, to August 31, 2004) and that were included as "13th month" transactions in the 2003 deferral account reconciliation application; and
- transactions that occurred from February 1, 2004 (and, for losses, from September 1, 2004) to JulyMarch 31, 20072008 — that is, after the data cut-off date for the 2003 deferral account reconciliation.

The net impacts of adjustment transactions on 1999-2002 deferral account balances are:

- an undercollection of \$0.003 million for 1999,
- an overcollection of \$0.06 million for 2000,
- an overcollection of \$79.7 million for 2001, and
- an overcollection of \$29.032.3 million for 2002.

Table 68-1 provides a summary by main revenue and cost categories of the adjustment transactions included in this application which relate to years prior to 2003. These transactions occurred from January 1, 2003 to JulyMarch 31, 20072008, as discussed above, and determine the overall deferral account balances for 1999, 2000, 2001, and 2002 that remain outstanding as of JulyMarch 31, 20072008.

### **68.1 1999-2001 Deferral Account Adjustments**

The undercollection of \$0.003 million for 1999 and overcollection of \$0.06 million for 2000 are very small. The amounts are well below the materiality thresholds of  $\pm$ \$50,000 for single-customer revenue and about  $\pm$ \$7 million for total costs, as determined during stakeholder consultation and discussed in Appendix A of this application. Therefore, the adjustments for 1999 and 2000 have simply been added to the \$79.7 million overcollection arising from adjustments related to 2001 for reconciliation and allocation purposes in this application.

Appendix M Comparison — Pre-2003 Deferral Accounts  
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Table 68-1 1999-2002 Deferral Account Adjustments Summary, \$ 000 000

Line No.	Deferral Account Adjustments (\$ 000 000)				Totals	
	2002 (a)	2001 (b)	2000 (c)	1999 (d)	1999-2002 (e)	
	<u>Recorded Revenue Adjustment Increases (Decreases)</u>					
	<u>Recorded Revenue Adjustment Increases (Decreases)</u>					
1	Interconnection	(0.6)	(0.1)	-	-	(0.6)
2	Losses	(1.2)	(0.0)	-	-	(1.2)
3	Operating Reserve	(0.0)	0.0	-	-	0.0
4	Other System Support	(0.1)	(0.0)	-	-	(0.1)
5	<b>Total Revenue Adjustments</b>	<b>(1.9)</b>	<b>(0.1)</b>	<b>-</b>	<b>-</b>	<b>(2.0)</b>
	<u>Recorded Cost Adjustment Decreases (Increases)</u>					
6	Wires	15.98	7.7	0.1	-	23.76
7	Ancillary Services	(0.7)	(0.1)	(0.1)	(0.0)	(0.8)
8	Losses	1516.6	02.2	0.0	-	1518.8
9	Other Industry	0.0	-	-	-	0.0
10	General & Administrative	0.023	-	-	-	0.023
11	<b>Total Cost Adjustments</b>	<b>30.8341</b>	<b>79.8</b>	<b>0.1</b>	<b>(0.0)</b>	<b>38.744.0</b>
	<u>Deferral Account Adjustment Surplus (Shortfall)</u>					
12	<b>Net Surplus (Shortfall)</b>	<b>29.032.3</b>	<b>79.7</b>	<b>0.1</b>	<b>(0.0)</b>	<b>36.842.1</b>

Note: Numbers may not add due to rounding.

5 Table 68-2 provides a summary of the impact of 1999-2001 adjustments on deferral account balances by rate component. Adjustments to revenues have been small, with a net total decrease in revenue of \$0.1 million. Adjustments to costs have been somewhat larger, with a net total decrease in costs of \$79.9 million.

10 The largest of the 1999-2001 cost adjustments affect the interconnection charges deferral account balance, which has increased to an overcollection of \$7.7 million primarily due to adjustments resulting from EUBAUC decisions affecting TFO revenue requirements as follows:

- 15 • a refund of \$7.0 million from TransAlta to reflect a reduction in federal income tax rates for 2001 and to reflect Rainbow Pipeline tax case results for 2001, ordered in Decision 2004-028 dated March 23, 2004 regarding TransAlta's Final Transmission Tariff for January 1 to April 30, 2002;
- a refund of \$0.6 million relating to an overpayment of a depreciation adjustment resulting from ATCO Electric's 2001-2002 Isolated Generation Application; and
- 20 • a refund of \$0.3 million from ATCO Electric to reflect tax savings from capital repair costs for 2001 ordered in Decision 2004-104 dated December 7, 2004 regarding ATCO Electric's Disposal of 2003 Transmission and Distribution Deferral Account Balances.

Adjustments to other cost components were not significant for the 1999-2001 deferral accounts. The impact of all 1999-2001 cost and revenue adjustments is a deferral account

~~net balance increase to an overcollection of \$7.8 million, which represents about 1% of recorded costs for 2001.~~

*Table 6-2 — 1999-2001 Deferral Account Adjustments, \$ 000 000*

Cost adjustments have also affected the 1999-2001 losses deferral account balance, which has increased to an overcollection of \$2.2 million primarily due to the \$2.0 million refund arising from suspended TA Adjustments attributable to 2001 as discussed in section 5.1.3 of this application.

*Table 8-2 — 1999-2001 Deferral Account Adjustments, \$ 000 000*

Line No.		Deferral Account Adjustments		Net Over (Under) Collection Variance (c)=(a)+(b)
		Recorded Revenue (a)	Recorded Costs (b)	
<b>Demand Transmission Service</b>				
1	Interconnection	(0.0)	4.5	4.5
2	Operating Reserve	0.0	-	0.0
3	Other System Support	(0.0)	(0.1)	(0.1)
4	<b>Total DTS</b>	<b>(0.0)</b>	<b>4.4</b>	<b>4.3</b>
<b>Supply Transmission Service</b>				
5	Interconnection	(0.0)	3.3	3.2
6	Losses	(0.0)	02.2	02.2
7	Operating Reserve	(0.0)	-	(0.0)
8	<b>Total STS</b>	<b>(0.1)</b>	<b>35.5</b>	<b>35.4</b>
<b>Total DTS and STS</b>				
9	Interconnection	(0.1)	7.8	7.7
10	Losses	(0.0)	02.2	02.2
11	Operating Reserve	0.0	-	0.0
12	Other System Support	(0.0)	(0.1)	(0.1)
13	<b>Total DTS and STS</b>	<b>(0.1)</b>	<b>79.9</b>	<b>79.8</b>

Note: Numbers may not add due to rounding.

Adjustments to other cost components were not significant for the 1999-2001 deferral accounts. The impact of all 1999-2001 cost and revenue adjustments is a deferral account net balance increase to an overcollection of \$9.8 million, which represents about 1% of recorded costs for 2001.

Additional information on the 1999-2001 cost and revenue adjustments discussed above are provided in Appendix E-1 of this application. The allocation of the 1999-2001 deferral account adjustments to customers is discussed in section 79 of this application.

## 68.2 2002 Deferral Account Adjustments

Adjustments related to 2002 result in a net ~~\$28.9~~32.3 million overcollection for reconciliation and allocation purposes in this application.

Table ~~68~~-3 provides a summary of the impact of 2002 adjustments on deferral account balances by rate component. Adjustments to revenues have been relatively small, with a net total decrease in revenue of \$1.9 million. Adjustments to costs have been larger, with a net total decrease in costs of ~~\$30.8 million~~.

~~The largest of the 2002 cost adjustments affect the losses charges deferral account balance, which has increased to an overcollection of \$14.4~~34.1 million, primarily due to the 2002 portion of a one-time adjustment to energy market settlement data as discussed in section 5.2.2 of this application.

Table ~~68~~-3 2002 Deferral Account Adjustments, \$ 000 000

Line No.	Deferral Account Adjustments		Net Over (Under) Collection Variance (c)=(a)+(b)	
	Recorded Revenue (a)	Recorded Costs (b)		
<b>Demand Transmission Service</b>				
1	Interconnection	(0.2)	9.2	8.9
2	Operating Reserve	0.1	(0.4)	(0.3)
3	Other System Support	(0.1)	0.2	0.1
4	<b>Total DTS</b>	<b>(0.2)</b>	<b>9.0</b>	<b>8.7</b>
<b>Supply Transmission Service</b>				
5	Interconnection	(0.3)	6.7	6.3
6	Losses	(1.2)	<del>15.6</del> <u>18.9</u>	<del>14.4</del> <u>17.7</u>
7	Operating Reserve	(0.1)	(0.4)	(0.5)
8	<b>Total STS</b>	<b>(1.6)</b>	<b><del>21.8</del><u>25.2</u></b>	<b><del>20.2</del><u>23.5</u></b>
<b>Total DTS and STS</b>				
9	Interconnection	(0.6)	15.8	15.3
10	Losses	(1.2)	<del>15.6</del> <u>18.9</u>	<del>14.4</del> <u>17.7</u>
11	Operating Reserve	(0.0)	(0.9)	(0.9)
12	Other System Support	(0.1)	0.2	0.1
13	<b>Total DTS and STS</b>	<b>(1.9)</b>	<b><del>30.8</del><u>34.1</u></b>	<b><del>28.9</del><u>32.3</u></b>

Note: Numbers may not add due to rounding.

~~The largest of the 2002 cost adjustments affect the losses charges deferral account balance, which has increased to an overcollection of \$17.7 million, primarily due to \$13.0 million attributed to 2002 for the one-time adjustment to energy market settlement data as discussed in section 7.2.2 of this application. The cost adjustments affecting losses also includes the \$1.0 million refund arising from suspended TA Adjustments attributable to 2002 as discussed in section 5.1.3 of this application.~~

The interconnection charges deferral account balance has also increased to an overcollection of \$15.3 million primarily due to adjustments resulting from the following

| **EUBAUC** decisions regarding TFO tariffs:

- a refund of \$13.8 million from AltaLink due to the difference between interim and final TFO tariffs for 2002, ordered in Decision 2004-028 dated March 23, 2004 regarding AltaLink's Final Transmission Tariff for May 1 to April 30, 2004; and
- a refund of \$2.9 million from TransAlta to due to the difference between interim and final TFO tariffs for January to April 2002, ordered in Decision 2004-028 dated March 23, 2004 regarding TransAlta's Final Transmission Tariff for January 1 to April 30, 2002;

The interconnection charges deferral account balance also includes smaller amounts reflecting a decrease to ATCO Electric's 2002 TFO revenue requirement in Decision 2004-104, incremental 2002 revenue requirement amounts for Enmax TFO, and an increase to 2002 farm transmission costs for Aquila Networks Canada (now FortisAlberta) in Decision 2003-019.

Adjustments to other cost components were not significant for the 2002 deferral accounts. The impact of all 2002 cost and revenue adjustments is a deferral account net balance increase to an overcollection of \$~~28.9~~32.3 million, which represents about 4% of recorded costs for 2002.

Additional information on the 2002 cost and revenue adjustments discussed above are provided in Appendix E-1 of this application. The allocation of the 2002 deferral account adjustments to customers is discussed in section 7-9 of this application.

## **79 ALLOCATION TO CUSTOMERS**

5 Deferral account balances and adjustments are allocated to customers as in prior deferral account reconciliation applications, and in accordance with the conclusions reached during the stakeholder consultation discussed in Appendix A of this application.

### **79.1 Allocation of ~~2003, 2004, and 2005~~ to 2007 Deferral Account Balances**

10 As in the previous deferral account reconciliation application for 2003, deferral account balances are calculated on a production month basis as the costs paid by rate and revenue rate component for ~~2003, 2004, and 2005~~ each year from 2003 to 2007. (Deferral accounts in prior years were reconciled on an accounting month (for 2002) or accounting year (for 1999-2001) basis.) Consistent with treatment in prior years, these deferral account balances have been allocated to individual customers based on each customer's  
15 percentage of total revenue collected based on the rates in place during the period, by month (or year) and by rate component, except for losses.

20 ~~Also as in the 2003 deferral account reconciliation application, deferral account balances associated with losses for 2003, 2004, and 2005. 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, AR 86/2007. There is accordingly no allocation of losses deferral account balances to customers included in this application for 2006 and 2007.~~

25 ~~Deferral account balances associated with losses for 2003, 2004, and 2005 remain subject to retrospective deferral account reconciliation and are included in this application. As in the 2003 deferral account reconciliation application, those 2003, 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 2003, 2004, and 2005, generators paid losses charges on the basis of normalized loss factors, which are the aggregate of "raw" loss  
30 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.

35  
40  
45 After the allocation of deferral account balances is determined by rate and rate component for each customer, the Rider C revenue already paid by each customer is subtracted 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.

5 For 2003, the second reconciliation in this application includes deferral account charges or refunds relating to 2003 which were financially settled in 2005 as a result of the first reconciliation proceeding. The Rider C revenue by customer that is subtracted from the deferral account balances includes the settlement amounts approved in the 2003 deferral account reconciliation proceeding.

## 79.2 Allocation of Prior-Year Deferral Account Adjustments

10 As concluded during the stakeholder consultation discussed in Appendix A of this application, adjustments relating to years prior to 2003 are allocated to customers using the final allocators approved by the EUBAUC for each of those years. Adjustments relating to 1999 and 2000 are allocated together with amounts relating to 2001, as discussed in section 68.1 of this application, by rate and rate component using the 2001 annual allocators approved in EUBAUC Decision 2003-099. Adjustments relating to 2002 are allocated by rate and rate component using the 2002 monthly allocators approved in EUBAUC Decision 2003-099.

## 9.3 Provision of Customer Allocation Information

20 The results of the deferral account allocation for each DTS and STS customer are included in Appendices H ~~through M, J, K, and L~~ of this application, in annual customer detail summaries and customer allocation detail. As discussed in section 2.6 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 (including the 2004-2005 deferral account reconciliation application filed on December 1, 2007).

30 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 H, J, K, and L, in Microsoft Excel format.

40 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 2006 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.

45

5 This treatment of deferral account allocations to System Access Service Agreements that have been assigned applies to assignments effective in 2002 and later years. The AESO is unable to apply similar treatment to assignments effective in 2001 and prior years due to a lack of detailed assignment data for those years. As well, assignees will be determined as of the ~~date of settlement of the deferral account reconciliation after approval by the EUB, and not as of the July-March 31, 2007-2008~~ data cut-off date for this application.

#### 9.4 Application of GST to Deferral Account Balances

10 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 1999, 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 AUC approves the interim settlement of customer charges and refunds as discussed in section 1.2 of this application.

20 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.

30 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.



**810 PROPOSED METHOD OF REFUNDING AND COLLECTING**

5 Consistent with the approach approved for the AESO's 2003 deferral account reconciliation, the AESO proposes to make a one-time payment and collection option to settle the outstanding deferral account balances.

10 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 EUBAUC decision regarding this application.

15 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.

20

### 10.1 Immediate Interim Settlement

As discussed in section 1.2 of this application, the AESO proposes that the refunds and charges due to customers as a result of this application be settled as soon as possible on an interim refundable basis. The AESO notes the AUC commented in its April 16, 2008, letter, "Prior to ordering immediate financial settlement arising from a revised application, however, the Commission must be satisfied that the amounts are accurate and that such an order is in the public interest."

The AESO considers that the reasons set out in section 1.2 provide support that interim settlement of the deferral account balances in the amounts allocated in this application would be accurate and in the public interest. The AESO will therefore plan interim settlement on invoices issued in July 2008, pending approval of the AUC.

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

*Table 10-1 Distribution of Charges and Refunds Among Customers*

<u>Range of Refunds and Charges</u>	<u>DTS</u>	<u>STS</u>
Refund Greater Than \$100,000	7	23
Refund of \$100,000 to Charge of \$100,000	37	18
Charge Greater Than \$100,000	5	0
Total Number of Customers	49	41

As already noted, the amounts settled on invoices issued in July 2008 would be interim and refundable, and subject to adjustment in the final decision on the 2004-2007 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 2008 deferral account reconciliation application expected to be filed in the second quarter of 2009.

If no material adjustments are required, the AESO suggests it may be efficient 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.

**911**    **RESPONSES TO DIRECTIONS**

Previous **EUBAUC** decisions on AESO deferral account reconciliations included various directions to the AESO.

5

Decision 2003-099 on the AESO's deferral account reconciliations for 2000, 2001, and 2002 included 20 directions to the AESO. The majority of these directions were responded to immediately following the issuing of the decision and in the AESO's deferral account reconciliation application for 2003 filed on June 4, 2004.

10

Additional directions, which required the AESO to evaluate Rider C in a trial period in 2004 and to provide the results of the trial and a recommended rider methodology to be used for 2004, were responded to in a compliance filing on October 21, 2004.

15

Decision 2005-034 on the AESO's 2003 deferral account reconciliations included two directions to the AESO. Responses to those directions are summarized in this section.



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**1 Distribute 2003 Deferral Account Balances by June 30, 2005** Page 1 of 1

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**Direction**

5 In light of the above, and the Board's finding in Section 3 of the Decision in respect of the  
carry over of 2002 amounts into the 2003 reconciliation, the Board considers that the  
distribution of 2003 deferral account balances to AESO customers should occur as soon as  
possible on the basis of the distribution proposed by the AESO in the Revised Application.  
Accordingly, the Board directs that by June 30, 2005, the AESO shall make refunds to and  
10 obtain collections from AESO customers in accordance with the distribution of 2003 deferral  
account balances as provided for in Appendix D of the Revised Application. [p. 12]

**Response**

15 The AESO made all refunds and collections associated with the 2003 deferral account  
reconciliation on June 28, 2005, concurrent with the May 2005 transmission tariff billings  
issued on that day.

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**2 Identify and Propose Disposition of Prior Period Adjustments** Page 1 of 1

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**Direction**

5 Accordingly, the Board directs the AESO, in its 2004 deferral account application, to re-file a  
version of Table 5 from the 2003 Application with three additional columns to indicate 2002  
carry forward adjustments, 2003 carry forward adjustments not yet accounted for, and a final  
“pure” determination of 2003 costs after removal of 2002 carry forward adjustments and the  
inclusion of 2003 carry forward adjustments. Further, the Board directs the AESO, in its  
10 2004 deferral account application to propose a methodology for the disposition of the 2003  
carryover. [p. 13]

**Response**

15 Amounts included in the AESO’s 2003 deferral account reconciliation which relate to other  
years, and removal of those amounts to provide a “pure” determination of 2003-only costs,  
are discussed in section 2.3 and summarized in Tables 2-2 and 2-3 of this application.  
Additional detail is provided in sections 57.1 and 57.2 and in Appendix E-1 of this  
application.

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**3 Provide Comparisons of Applications and IR Responses** Page 1 of 1

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**Direction**

To facilitate the parties' and the Commission's review, the Commission considers it appropriate that the revised application include a blackline showing all changes made to the Application, along with a table of concordance or blackline of the IR responses to make clear what page references or other changes are required in order for the AESO's IR responses to be carried through to the revised application. [AUC Letter dated April 16, 2008]

**Response**

A redline comparison of the original 2004-2005 Deferral Account Reconciliation Application dated December 1, 2007, and this extended 2004-2007 Deferral Account Reconciliation Application is provided as Appendix M. As the appendices to the applications are provided as PDF files and have been extensively reorganized in this application, it is not practical to provide a redline comparison of the appendices (other than Appendix A, which is included with the redline comparison of the applications). However, a cross-references list of appendices has been included at the end of the redline comparison.

Revisions to the responses filed on March 18, 2008, to information requests on the original 2004-2005 application, are provided as Appendix N-1 of this application. A redline comparison of the original and revised responses is provided as Appendix N-2.

**APPENDIX A**  
**CONCLUSIONS OF 2004-~~2005~~-2008 STAKEHOLDER CONSULTATION**

5 Since the filing of the AESO's 2003 Deferral Account Reconciliation Application on June 2, 2004, the AESO has conducted extensive stakeholder consultation on the deferral account rider methodology and reconciliation processes.

- 10 • Consultation on the AESO's Decision 2003-099 Compliance Filing (dated October 21, 2004) and on the methodology to be used for future deferral account riders was held in November 2004.
- 15 • Consultation resulting from the AESO's 2003 deferral account reconciliation process, on the 2004 deferral account cut-off date and post cut-off adjustment process, was held from March through December 2005.
- 20 • Consultation on moving to a prospective deferral account rider methodology was held from May through September 2005.
- 20 • Consultation on filing an extended 2004-2007 application with immediate interim settlement was held in March 2008.
- 25 • Consultation on redistribution of interest in the AESO's extended 2004-2007 deferral account reconciliation application was held in April 2008.

25 The consultation activities included meetings, discussion papers, and requests for comments. A broad representation of AESO customers participated at various times in the consultation, and written comments were provided by ADC (Alberta Direct Connect Consumer Consumer's Association), AltaGas, ASBG/PGA (Alberta Sugar Beet Growers and Potato Growers of Alberta), ATCO Electric, ATCO Power, Calpine Canada, EnCana, ~~Enmax~~ENMAX, EPCOR Utilities, FIRM Customers, FortisAlberta, City of Medicine Hat, PICA (Public Institutional Consumers of Alberta), Cities of Red Deer and Lethbridge, TransAlta, TransCanada, and UCA (Utilities Consumer Advocate). The complete record of presentations, discussion papers, comments, and responses is currently available on the AESO's website at www.aeso.ca, by following the paths:

- 35 • Tariff ► Current Consultations ► 2004 Deferral Account Reconciliation Process,
- Tariff ► Current Consultations ► 2006 Prospective Deferral Account Rider, ~~and~~
- Tariff ► Previous Applications ► 2004 Deferral Account Rider Evaluation, ~~and~~
- Tariff ► Current Applications ► 2004-2005 Deferral Account Reconciliation, and
- 40 • Tariff ► Current Applications ► 2004-2007 Deferral Account Reconciliation.

45 The stakeholder consultation in 2004 and 2005 was held to specifically review matters raised in the deferral account reconciliation applications for 2000-2002 and for 2003, and also to more generally discuss the deferral account reconciliation process. The consultation held in 2008 addressed the specific matters of filing an extended 2004-2007 application with immediate interim settlement and of redistribution of interest in the AESO's deferral account reconciliation application.

5 Some of the conclusions reached in the 2004 and 2005 consultation have been modified or are less relevant as a result of later discussions, development of the software program used for deferral account reconciliation, and other changes relating to deferral account reconciliations. The AESO has incorporated many of the conclusions reached during consultation into this application, sometimes modified if appropriate, and thereby expects that the regulatory review process for the deferral account reconciliations ~~may~~ be relatively expeditious.

10 ~~In particular, one~~ The AESO considers the most significant conclusion of the stakeholder consultation ~~was to be~~ that deferral account balances for 2003 and later years should be subject to adjustment and re--reconciliation after the first reconciliation approved by the EUB-AUC. This conclusion recognizes that material adjustments frequently occur after the data cut-off date used for the first reconciliation application. To ensure that customer impacts resulting from material adjustments are the same regardless of when they occur, the deferral account balances should be included in a second reconciliation application (and potentially a third one) in subsequent years. In accordance with this conclusion, the AESO has provided in section 5 of this application a second reconciliation of 2003 deferral account balances.

20 A summary of the conclusions reached during these consultations, as well as a description of several aspects of the resulting deferral account reconciliation process, is provided in the following sections. Each section first provides the conclusion (in italicized text) and then provides background information relating to each conclusion. If appropriate, updates indicating modifications to the conclusion or comments on current relevance of the conclusions precede the conclusion itself.

25 The AESO believes these conclusions were generally supported by a majority of stakeholders involved in the consultation process, although with the specific exception of the redistribution of interest discussed in section A-13 on which consensus views were not expressed. The AESO also notes that not every stakeholder expressed opinions on every matter and support was not necessarily unanimous.

#### **A-1 Data Cut-Off Date**

35 Update: The AESO now proposes a data cut-off date after initial settlement in December (as discussed in section 2.8) rather than the original conclusion of August 31 as presented below.

- 40 • *The cut-off date for data to be included in the deferral account reconciliation will be August 31 of the following year.*

An August 31 cut-off date would include all revenue and cost adjustments received to that date. An August 31 cut-off date would also include final transmission system losses for the deferral account year.

45 The AESO notes that the data cut-off date used for this application was March 31, 2008, only three months after the 2007 deferral account year-end. 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, which removes the need to include final transmission system losses in the application.

5 As well, in follow-up to questions asked at the February 8, 2008 technical meeting on the 2004-2005 deferral account reconciliation application, the AESO examined the impact of interim and final settlement on deferral account allocations to load customers and found there was no significant change to load customer energy volumes and DTS charges between initial, interim and final settlements. The change in deferral account allocation which would result from the volume changes would be expected to be below the  $\pm$ \$50,000 materiality threshold for individual customer revenues discussed in Appendix A-4 of this application.

10 Therefore, based on the current quality of settlement data, the AESO now considers that it could prepare a deferral account reconciliation application immediately after initial settlement of December volumes, with minimal impact on the accuracy of deferral account allocations to customers.

## 20 **A-2 Application Filing Date**

- *The filing date for the deferral account reconciliation application will be as soon after the data cut-off date as possible.*

25 The AESO initially anticipated that it would require two and a half months after the data cut-off date to prepare a deferral account reconciliation application. However, later consultation concluded that each deferral account application would include up to three separate annual reconciliations, as described in section A-5 and A-6 below. Multi-year reconciliation applications will require additional preparation time beyond that required for a single-year application.

30 During consultation, the AESO also expected to file its 2004 deferral account reconciliation application in late 2005. However, the AESO found that the multi-year reconciliation (first reconciliation for 2004, second reconciliation for 2003, and adjustments for 1999-2002) was a more difficult process than expected.

35 The steps involved in a retrospective deferral account reconciliation involve complex and resource-intensive activities, particularly the assignment of costs to the “production months” to which they relate, and the determination of the deferral account balance and customer revenue by rate component for each month in the calendar year. The AESO concluded it was appropriate to develop an automated process that queries the AESO’s accounting and billing systems to populate a database with all cost and revenue amounts by customer and by production month. The AESO has developed such a systemprogram and has used it for this 2004-~~2005-2007~~ deferral account reconciliation application.

45 Beyond the development of the deferral account reconciliation systemprogram, this application was further delayed by AESO resources being directed to other regulatory proceedings, in particular the 2005-2006 tariff application and refiling and the 2007 tariff

consultation and application. However, the AESO considered it appropriate to delay this application until all matters raised in prior applications and in consultation could be adequately addressed, and until it was confident the reconciliations and customer allocations were complete and accurate.

5 The AESO anticipates that the automated deferral account reconciliation system program developed for the original 2004-2005 application and this extended 2004-2007 application will allow future deferral account reconciliation applications to be filed about three months after the data cut-off date, ~~resulting in filing in late November or early December following a data cut-off date of August 31. If a data cut-off date immediately after year-end is used, as discussed in the preceding section A-1, a deferral account reconciliation application could be filed in the second quarter after the deferral account year-end.~~

### 15 A-3 Materiality Threshold for Costs

Update: Given the commitment to filing a second reconciliation application (and potentially a third one) for each deferral account year, the consideration of materiality thresholds may be less important than it initially was.

- 20 • *For AESO costs, post cut-off adjustments will be considered material if the cumulative adjustments for a single cost component or the cumulative adjustments for total costs exceed  $\pm 1\%$  of the AESO's annual revenue requirement.*

25 During consultation, the AESO and stakeholders discussed the possibility of recalculating and refile a deferral account reconciliation if **material** adjustments arose which affected the deferral account balances. A material adjustment was defined as one that would have a significant impact on the amount of the deferral account balances allocated to the AESO's customers. However, the impact on the allocation to customers would not be certain until all the reconciliation calculations were complete, and determining that an impact is not  
30 significant after completing the reconciliation work would not be an efficient use of time and resources. Therefore, stakeholders generally supported the establishment of materiality thresholds for deferral account adjustments, in advance of completing the allocation to customers.

35 As consultation continued, the question of materiality thresholds became less important as multiple annual reconciliations were contemplated to include all deferral account adjustments, as discussed in section A-5 and A-6 below. However, materiality considerations affect decisions as to whether reconciliations beyond a second annual reconciliation must be done, and are therefore still relevant.

40 Consultation also highlighted that the materiality threshold for AESO costs differs from that for AESO revenues, and should therefore be determined separately.

45 **AESO costs** comprise wires, ancillary services, losses, (included in retrospective deferral account reconciliations only for 2005 and prior years), and "own costs" cost components, as well as revenue offsets such as Customer-Owned Substation (COS) credits. Adjustments to costs affect the deferral account balance but do not affect the relative allocation of that

balance between customers, since the deferral account balance is allocated based on AESO revenue collections from customers (except for losses which are allocated on production times pool price), and revenue collections are unaffected by adjustments to costs.

5

For adjustments to AESO costs, the AESO concluded that an adjustment would be considered material when it was greater than ±1% of the AESO's annual revenue requirement. Such an adjustment to costs would correspondingly have a greater than ±1% impact on the total revenue collection from an individual customer with respect to the deferral account reconciliation year.

10

As an illustration, the AESO's annual revenue requirements for the 2005 and 2004 deferral account years included in this application were \$782.9 million and \$757.5 million respectively. The resulting ±1% cost materiality threshold would be ±\$7.8 million for 2005 and ±\$7.6 million for 2004. This level of materiality threshold is also comparable to the working capital deficiency or surplus trigger level of \$7.0 million used for the AESO's Rider B.

15

#### A-4 Materiality Threshold for Revenues

20

Update: Given the commitment to filing a second reconciliation application (and potentially a third one) for each deferral account year, the consideration of materiality thresholds may be less important than it initially was.

25

- For **AESO revenues**, post cut-off adjustments would be considered material if the cumulative adjustments for a single revenue component (interconnection, operating reserve, other system support, or transmission losses for 2005 and prior years) for a single customer or the cumulative adjustments for total revenue for a single customer exceed the exact threshold determined for "a" through trial-and-error solution of the following equation:

30

$$\cancel{\$50,000} = \cancel{\left[ (D + a) \times \frac{(r + a)}{(R + a)} \right] \frac{Dr}{R}} \quad \underline{\$50,000 = \left[ (D + a) \times \frac{(r + a)}{(R + a)} \right] - \frac{Dr}{R}} \quad (\text{eq. 1})$$

where, by revenue component and in total:

35

*D* = original deferral account balance total for all customers being adjusted

*a* = cumulative adjustments to revenue for an individual customer

*R* = annual revenue from all customers before adjustment over which deferral account will be allocated

40

*r* = annual revenue from the individual customer

**AESO revenues** comprise charges collected from customers for interconnection, operating reserve, other system support, and transmission losses charges collected from customers (included in retrospective deferral account reconciliations only for 2005 and prior years). Adjustments to revenue affect both the deferral account balance and the basis for

45

the allocation of that balance to customers. That is, a revenue adjustment will affect the revenue collection from an individual customer, and will therefore increase or decrease the deferral account balance allocated to that individual customer, independent of any change to the deferral account balance.

5

For clarity, this consideration does not affect the billing of the revenue adjustment to the customer involved. The individual customer would be billed the revenue adjustment according to standard billing practices of the AESO. Rather, this discussion relates to what may be considered the “second order effects” that the revenue adjustment has on the allocation of deferral accounts based on customer revenue.

10

The amount of a deferral account adjustment that is allocated to a customer depends on three factors:

15

- (i) the size of the deferral account balance being adjusted,
- (ii) the individual customer’s revenue, and
- (iii) the size of the total revenue over which the deferral account will be allocated.

This is illustrated by the fundamental deferral account (DA) allocation formula:

20

$$\begin{aligned}
 & \text{DA Allocation} = \text{DA Balance} \times \frac{\text{Customer Revenue}}{\text{Total Revenue}} \\
 \text{DA Allocation} &= \text{DA Balance} \times \frac{\text{Customer Revenue}}{\text{Total Revenue}} \qquad \qquad \qquad \text{(eq. 2)}
 \end{aligned}$$

For a customer who receives a revenue adjustment, the adjustment affects each of the deferral account balance, the customer revenue, and the total revenue when determining the adjusted allocation to that customer:

25

$$\begin{aligned}
 & \frac{\text{Adjusted Allocation}}{\text{Allocation}} = \frac{(\text{DA Balance} + \text{Adjustment}) \times \text{Customer Revenue} + \text{Adjustment}}{\text{Total Revenue} + \text{Adjustment}} \\
 \text{Adjusted Allocation} &= (\text{DA Balance} + \text{Adjustment}) \times \frac{\text{Customer Revenue} + \text{Adjustment}}{\text{Total Revenue} + \text{Adjustment}} \qquad \qquad \qquad \text{(eq. 3)}
 \end{aligned}$$

30

For adjustments to AESO revenues, the AESO concluded that an adjustment would be considered material when it would change the deferral account allocation to a customer by greater than ±\$50,000. Further examination of the deferral account allocation formulas presented above shows that the revenue adjustment materiality threshold can then be determined by solving for “a” in equation 1 as presented above. The AESO will use equation 1 to determine the materiality threshold for revenue adjustments for each annual deferral account reconciliation.

35

40

The AESO notes that a simplified formula was also discussed with stakeholders that may be used as a “rule of thumb” to assess whether a revenue adjustment is near the materiality threshold. The “rule of thumb” formula is:

$$\text{Materiality Threshold} = \frac{50,000 \times \text{Total Revenue}}{2 \times \text{Deferral Account Balance}} \quad (\text{eq. 4})$$

5 The “rule of thumb” formula is much simpler to calculate, but give a less precise threshold than the more exact formula presented in equation 1 due to simplifying assumptions incorporated in its derivation.

10 Consultation also suggested a higher materiality threshold might be appropriate for distribution facility owners (DFOs) compared to AESO direct connect customers. The AESO proposes that the same materiality threshold apply to all customers, as DFOs serve some transmission-connected customers who receive a flowthrough of the AESO’s charges including deferral account allocations. Applying a higher materiality threshold for DFOs might result in different treatment for such transmission-connected DFO customers compared to AESO direct connect customers which, in the AESO’s opinion, would be  
15 inappropriate.

20 Equation 1 includes individual customer revenue “r” in the formula, and therefore would result in a different threshold level of adjustment for every customer of the AESO. However, the lowest threshold level of adjustment arises from the customer with the highest revenue. The AESO’s highest revenue from a single direct connect customer (which currently represents about 1.25% of the AESO’s total revenue) will be substituted into equation 1 to determine the materiality threshold for adjustments to AESO revenues. (Revenue from DFOs is not considered, as resulting adjustments are spread over many DFO end-use customers and would not result in any single end user receiving a ±\$50,000 deferral account  
25 allocation adjustment.)

### A-5 Second Reconciliation of Deferral Accounts

- 30 • *Material adjustments occurring after a deferral account reconciliation application’s cut-off date will be included in a second reconciliation of the deferral account in the following year.*

35 The AESO and stakeholders support the principle that the treatment of a material deferral account adjustment should not depend on when that adjustment happens. This principle leads to the conclusion that material adjustments must always be subject to full reconciliation. The AESO therefore proposes that full annual reconciliations be filed at least twice — the first reconciliation in the year following the deferral account, and the second reconciliation in the next year following. The AESO further proposes that these first and second reconciliations include all deferral account adjustments, both material and non-  
40 material, and that these reconciliations be performed regardless of whether a material adjustment has occurred or not. The AESO believes this will address the treatment of the majority of material adjustments that occur after the data cut-off date for the first reconciliation.

## A-6 Third Reconciliation of Material Adjustments

- *Material adjustments occurring after a data cut-off date will be included in a subsequent annual reconciliation of the deferral account, for up to a total of three annual reconciliations. After the third reconciliation this process will be reviewed with stakeholders to determine if further annual reconciliations should be completed.*

As discussed in section A-2 above, the AESO has developed an automated process that extracts all cost and revenue amounts from the AESO's accounting and billing systems by customer and by production month. With such an automated process, the AESO considers it practical to complete annual retrospective deferral account reconciliations beyond the second reconciliation discussed in section A-5 above, for material adjustments to deferral account balances. The AESO suggests, however, that annual reconciliations should not continue indefinitely, but at this point does not have a basis for setting a maximum number of annual reconciliations. The AESO proposes that, initially, a third reconciliation be completed where material adjustments occur, and a further review of the process be conducted with customer consultation before completing additional reconciliations.

The AESO further proposes that if no material adjustments occur after the data cut-off date for the second reconciliation, a third reconciliation would not be performed. Instead, all non-material adjustments would be allocated to customers using the allocators most recently approved by the [EUBAUC](#) for the relevant deferral account year, as discussed in section A-9 below. This approach recognizes that even with an automated process, a full annual reconciliation will continue to require resources to complete.

The AESO also does not propose to complete any further reconciliations for the 1999-2002 deferral accounts. The consultation conducted in 2004 and 2005 resulted from concerns raised during the AESO's 2003 deferral account reconciliation process, and the AESO believes they should not be retroactively applied to years before 2003. As well, changes to the AESO's information systems make it more difficult to perform additional reconciliations for those periods. The AESO proposes that any adjustments relating to years before 2003 be allocated to customers using the final allocators approved by the [EUBAUC](#) for each of those years. The AESO notes that annual allocators were approved for 1999, 2000, and 2001 deferral accounts, while monthly allocators were approved for 2002. Therefore all adjustments related to those periods will be assigned to appropriate years (for 1999, 2000, and 2001) and months (for 2002) and allocated using the relevant allocators approved in Decision 2003-099.

## A-7 Inclusion of Non-Material Adjustments in Re-Reconciliations

- *If a material adjustment occurs after the data cut-off date, all non-material adjustments after the cut-off date will be included in the subsequent reconciliation of the deferral account in the next year's deferral account reconciliation application.*

The inclusion of non-material adjustments in second and subsequent reconciliations is a practical and efficient approach when an automated process can be used as discussed in section A-6 above.

## A-8 Allocation of Non-Material Adjustments Without Re-Reconciliation

5 Update: The AESO's experience with the software program developed for its deferral  
account reconciliations suggests that if a deferral account is settled for one year without  
reconciliation (that is, through use of previously-approved allocators), it is impractical to  
attempt full re-reconciliation in a later year. Essentially, once the full reconciliation is  
switched "off" for a particular deferral account period, the AESO anticipates it would be  
extremely difficult to switch it back "on" for a later application. The AESO therefore proposes  
10 that all 2003-2008 deferral accounts will be subject to re-reconciliation as part of its 2008  
application.

15 The AESO also considers that continuing to add an additional year of full reconciliation to  
each subsequent application is not practical. The AESO therefore proposes to consult with  
stakeholders in early 2009 (after the AUC issues its final decision on the extended 2004-  
2007 application), on when and on what basis full reconciliations should be permanently  
discontinued for a deferral account year. The AESO also expects to reconsider the  
possibility of a prospective methodology for its deferral accounts as part of such  
20 consultation. Any changes to the AESO's deferral account riders recommended by such  
consultation could be implemented no earlier than 2010, which suggests that full  
retrospective reconciliations would be included in the AESO's 2009 deferral account  
reconciliation application as well.

- 25 • *If no material adjustments occur after the cut-off date, all non-material adjustments after the cut-off date will be allocated to customers by production month based on the most recent **EUBAUC**-approved allocators for the deferral account, in the next year's deferral account reconciliation application.*

30 If no material adjustments give rise to an annual reconciliation in a third or subsequent year, the AESO proposes a simplified allocation as a pragmatic approach, given the minimal impact on customers of non-material adjustments. Such non-material adjustments would be allocated to customers as discussed in section A-9 below.

## A-9 Allocation of Non-Material Adjustments Using Prior Allocators

35 Update: See update comments under section A-8.

- 40 • *All non-material adjustments occurring after the next year's cut-off date will be allocated to customers by production month based on the most recent **EUBAUC**-approved allocators for the deferral account, in the next deferral account reconciliation application filed by the AESO.*

45 This approach was referred to as a "13th month" treatment during consultation, and simply refers to a method of collecting revenue and cost adjustments in a future year's application without associating them with a specific month of that future year. The "13th month" amounts are instead allocated on a basis other than a month in the future year. In effect,

adjustments for any period other than the year of the deferral account being reconciled are segregated from the 12 calendar months of the year.

5 In the AESO's 2003 deferral account reconciliation application, cost and revenue adjustments related to years prior to 2003 were accumulated in a "13th month" and allocated based on the 2003 annual revenue, which comprised total January 2003 to December 2003 revenue plus prior year revenue adjustments that had been included in the 2003 deferral account. A different approach has been applied by the AESO in the deferral account reconciliations in this application, and is proposed to be continued in future applications.

10 Non-material adjustments would continue to accumulate separately and be allocated in the next deferral account reconciliation application filed by the AESO. However, the non-material adjustments would be assigned to the production months of the original deferral account year to which they relate, and be allocated based on the monthly allocators approved by the EUBAUC in the most recent deferral account reconciliation decision for the deferral account year. If monthly allocators were not approved for the year, the previously-approved annual allocators would be used. To date, annual allocators have been approved for 1999, 2000, and 2001, and monthly allocators for 2002 and 2003.

#### 20 **A-10 Allocation of 2001-2003 Losses Adjustment**

25 Update: The 2001-2003 losses adjustment was included in the original 2004-2005 deferral account reconciliation application, and is also included in this extended 2004-2007 application.

- *The \$24.2 million adjustment relating to 2001-2003 losses is included in the prior year reconciliations filed with this 2004-2005 deferral account reconciliation application.*

30 A \$27.5 million adjustment relating to 2001-2003 losses was identified in the AESO's 2005-2006 General Tariff Application proceeding. The amount of the adjustment has since been updated to \$24.2 million, as noted in the AESO's Deferral Account Summary for May 2005. Consistent with the treatment of material adjustments discussed in section A-5 above, the adjustment is addressed in the second reconciliation of the 2003 deferral account included in this application.

35 The portion of the losses adjustment which is related to each of the years 2001, 2002, and 2003 has been attributed to each year, under the production month presentation discussed in section 2.2 of this application. The treatment of each year's portion is discussed in section 40 68.1 (for 2001), section 68.2 (for 2002), and section 57.2.2 (for 2003) of this application.

#### **A-11 Refunds or Collections of Amounts Less Than \$1,000**

- *An amount of less than \$1,000 arising from deferral account adjustments will be neither refunded to nor collected from a customer where the original customer is no longer the customer of the AESO and the service contract was not assigned to a current customer, but will instead be treated as an adjustment to AESO transmission costs.*

5 The AESO expects that the amount of deferral account allocation changes for some customers in the second, third, or subsequent annual reconciliations could be quite small. Over the three-year reconciliation period, it is also likely that some customers will terminate their services. The AESO notes that retrospective adjustments due to deferral account reconciliation are to apply to the customer for the service during the year to which the deferral account pertains, unless the customer assigned its contract to another party pursuant to the AESO's terms and conditions of service. As the number of annual reconciliations increases, the likelihood also increases that a service will have changed ownership without the contract being assigned. In such instances, the AESO considers it inefficient to pursue the previous customer for small retrospective deferral account adjustment amounts.

15 The AESO therefore proposes that it neither refund nor collect retrospective deferral account adjustment amounts of less than \$1,000 where the original customer is no longer the customer of the AESO and the service contract was not assigned to a current customer. Adjustments of less than \$1,000, where the original customer is no longer the customer of the AESO and the service contract was not assigned to a current customer, will be treated as an adjustment to appropriate rate and rate category of the AESO transmission costs in the current accounting year.

20 The AESO notes that the \$1,000 limit accords with the rebilling charge approved in paragraph 15.3(c) of the AESO's 2006 terms and conditions of service.

### 25 **A-12 Extended 2004-2007 Application and Immediate Settlement**

- *Suspending the 2004-2005 application and filing an extended 2004-2007 application including a request for immediate settlement is an appropriate means of addressing the current deferral account surplus.*

30 Shortly after filing its original 2004-2005 deferral account reconciliation application, the AESO's deferral account surplus increased materially due in part to additional amounts refunded to the AESO at the end of 2007 and in early 2008. As a result, the process for future deferral account applications proposed in the 2004-2005 application would not provide a prompt return of the full surplus to customers. The AESO therefore examined alternatives which could allow a more prompt settlement of the outstanding deferral account balances, and conducted a brief consultation process with stakeholders on possible options.

35 After reviewing various alternatives, the AESO proposed that the process for the 2004-2005 application be suspended after submission of responses to information requests, and that the application be replaced with an extended 2004-2007 application which the AESO would prepare and file in May 2008. The extended application would incorporate the full \$56.3 million deferral account surplus, or such other amount as had accrued at the application's data cut-off date. The application would accordingly include two additional sections on financial results and deferral account balances for 2007 and for 2006, as well as additional information for any prior years affected by the additional transactions being included. However, the methodology employed in the deferral account reconciliation and allocation

would be consistent with that employed in the 2004-2005 applicaiton, and the nature of the information included in the deferral account application would remain the same.

5 The AESO considered that the extended application would result in accurate reconciliation and allocation of all existing deferral account amounts to customers. At the time of filing the extended application, the AESO would also request approval for immediate financial settlement of the deferral account amounts with customers on an interim refundable basis.

10 Parties who expressed support for the AESO's proposal represented nearly all of the registered participants in the 2004-2005 deferral account proceeding, and no comments were received from any party opposing the proposal.

15 The AESO further considered that the process for reviewing the extended 2004-2007 application should allow additional participants to register (beyond those registered for the 2004-2005 application process), as the inclusion of additional years and additional amounts in the application may affect parties who were not affected by the 2004-2005 application.

### **A-13 Redistribution of Interest in Extended 2004-2007 Application**

- 20 • The AESO considers it appropriate to account for interest in the extended 2004-2007 deferral account reconciliation application because of the following unusual aspects of the application.
- 25 • The application will cover an extended period which includes first reconciliations for 2007, 2006, 2005, and 2004, as well as re-reconciliations or reconciliations of adjustments for years from 1999 to 2003.
  - The application has been delayed for the reasons discussed in Appendix A-2 of the original 2004-2005 application.
  - 30 • The application includes a number of large one-time adjustments, some of which are laid out in Schedule TCE.AESO-002 (b-c) in the AESO's information responses filed on March 18, 2008.

The AESO considers that redistribution of interest in the extended 2004-2007 application would be a one-time, extraordinary approach.

35 It is important to recognize that redistribution of interest will not affect the net deferral account balance being reconciled, since section 14 of the EUA requires that "on an annual basis, no profit or loss results from its [the AESO's] operation." The AESO must therefore be left with a zero balance after deferral account reconciliation, whether or not interest is redistributed.

40 For clarity, the AESO does not earn or incur interest directly on its deferral account balances, but rather deferral account surpluses and shortfalls are managed in conjunction with other financial obligations of the AESO. The AESO carries a certain amount of debt to provide working capital and fund capital purchases, and deferral account balances affect the amount of debt carried. The cost of interest incurred on debt accrues to the AESO's "own costs" which is allocated to AESO customers in accordance with the AESO's approved tariffs.

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5 Redistribution of interest will therefore result in amounts being moved between production years and months, between rates and rate components, and between customers. As discussed in Information Responses TCE.AESO-002 (e), -003 (d), and -009 (c), deferral account surpluses reduce debt balances that the AESO would otherwise have been required to carry, and therefore avoid interest expense. Similarly, deferral account shortfalls increase debt balances that the AESO would otherwise have been required to carry, and therefore incur additional interest expense. Redistribution of interest in the deferral account reconciliation would involve the following steps:

- 10 1. calculate the monthly interest expense or revenue that would have been incurred based solely on the outstanding deferral account balance,  
15 2. adjust interest expense that was actually incurred on a monthly basis to reflect the calculated increase or decrease in interest as calculated in step 1, and  
3. credit or charge an equivalent amount to the production periods, rates, and rate components relevant to the deferral account balance which gave rise to the interest expense adjustment.

20 The increase or decrease in interest expense would be allocated as incurred in a period in the same manner as interconnection charges in the AESO's deferral accounts. The equivalent credit or charge would be allocated on a production month basis in the same manner as the deferral account balance which gave rise to the interest expense adjustment. Amounts will therefore move between production periods, rates and rate components, and customers, although no change in net deferral account balance will occur.

25 The AESO held a meeting and written consultation process on redistribution of interest, and notes that parties were not unanimous in support for or opposition to the proposal. The AESO has laid out in section 2.3 of the application its reasons for concluding that in the extraordinary circumstances of this specific deferral account reconciliation application, it is appropriate to recognize and redistribute interest.

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