

2 2007 REVENUE REQUIREMENT

INTRODUCTION

5 Section 2 of this application outlines the AESO's 2007 revenue requirement for the purposes of the 2007 System Access Service Tariff. This section provides a summary of the key considerations as determined in the AESO's budget review process ("ABRP"), which is discussed in greater detail below.

10 As noted in the AESO's 2005/2006 General Tariff Application (GTA), the AESO is committed to making its planning and budgetary processes more transparent and with stakeholder input. The AESO is also committed to working with stakeholders and the Alberta Energy and Utilities Board (EUB) to find efficiencies to facilitate the regulatory process with respect to AESO costs.

15 In May 2005, the Budget Review Committee ("BRC") was established to participate in the AESO's 2006 and 2007 budgetary process. The intent of this stakeholder process was to provide a first level of prudence review and input with a resulting BRC recommendation provided by the AESO executive to the AESO Board for approval. By the time such budget items were filed with the EUB the items would have had a thorough vetting and scrutiny by interested parties, and thus it would be less likely that major disputes would remain unresolved. The EUB would continue to approve the allocation between customer classes for these costs, but the expectation was that revisiting a budget prudence matter would happen on an exception basis.

25 Based on the success of the BRC along with the directions expressed in the Department of Energy's November 28, 2005 Role and Mandates of Implementing Agencies Paper, the AESO endeavoured to further develop the consultation, review and AESO Board decision process in respect of the 2007-2008 budget. The intent was to ensure the process sufficiently furthers the objectives of involving stakeholders and minimizing the extent of review required by the EUB on matters that could reasonably be addressed in this way. The process was therefore set up to include a review of not only the AESO own costs forecast, but also forecast costs for ancillary services and transmission line losses. Transparency and inclusiveness were two of the primary principles behind the redesigned process, referred to as the AESO Budget Review Process, or ABRP. The process and underlying terms of reference were established and agreed upon with interested stakeholders prior to entering into the budget review. In support of the transparency objective, comments were provided in writing by all parties, and consistently shared by way of distribution to the participants in addition to posting to the AESO's website. No stakeholders were precluded from participating in the process at any point in time. The process model, schedule and the underlying terms of reference for the ABRP are attached to this Application as Appendix A, and described somewhat further below.

45 The process commenced with the AESO executive presenting a comprehensive strategic plan to the AESO Board in April, 2006. The strategic plan was further developed based on comments from industry stakeholders as well as AESO employees. The initiatives within the strategic plan have been used as the foundation in the development of the AESO's budget.

Using the DOE's directions and principles outlined in its November 28 paper, the AESO initially held a meeting with stakeholders on May 30, 2006 in order to initiate discussions respecting an appropriate consultation process for the determination of AESO General and Administrative Costs (including capital), Ancillary Services and Losses Costs, and Other Industry Costs. The AESO solicited feedback from all stakeholders concerning a process straw model as well as a Terms of Reference document. On June 20 the AESO posted a final detailed AESO Budget Review Process, a Terms of Reference, and a calendar detailing accountabilities by date leading up to an AESO Board Decision in early October 2006 (the calendar was further revised in July). As noted, these documents have been included as Appendix A. The process at a high level is as follows:

- 1.0 Notice to Stakeholders
- 2.0 AESO Develops Priorities and Strategic Plan
- 3.0 AESO Develops Own Costs, Ancillary Services and Line Losses
- 4.0 Technical Meeting to Review Forecast & Prior Year Actual Costs
- 5.0 AESO Board Decision; EUB Applications
- 6.0 Dispute or Appeal Process (To be Determined)

The majority of stakeholders and the AESO agreed that the process should be open to all stakeholders, the size of the group should not be limited, the process should be transparent to all, and that nothing would preclude stakeholders to ultimately appeal to the EUB. There were as many as nine stakeholders in attendance at each of the meetings for this review process. All written material for this process has been posted to the AESO's website and communicated to stakeholders in the AESO's stakeholder newsletter in order for all stakeholders to have had the opportunity to provide input. Part of the plan is also that the process will be re-evaluated with stakeholders at the end of each budget cycle and refinements made if necessary.

As a result of the Budget Review Process, on October 5, 2006, the AESO distributed an "AESO Board Decision Document". The document requested the AESO Board to approve the AESO's 2007/2008 Strategic Initiatives, General and Administrative Costs, General Capital, Losses Costs, Ancillary Service Costs, and Other Industry Costs, as recommended by AESO management based on the ABRP. These strategic initiatives and costs are fully discussed in this document. It also provides the supporting rationale, as well as an overview of the process undertaken by AESO management to arrive at the recommendation.

This information was discussed at the October 19, 2006 AESO Board meeting at which the AESO Board was asked to approve, or amend and approve, as appropriate, the items for 2007 noted above. As part of the agreed to consultation process behind the proposals in the document, prior to the AESO Board meeting, several stakeholder groups took the opportunity to meet with the AESO Board to discuss their written comments. These meetings were held on October 12, 2006.

The final result of the ABRP is AESO Board approval for:

1. AESO's 2007/2008 Strategic Initiatives

2. AESO's General & Administrative Costs of \$51.5 million for 2007 (see Cost Allocation Methodology in Section 2.8)
- Transmission Costs Recovery
\$35.7 million
 - Energy market Recovery
\$11.9 million
 - Load Settlement Recovery
\$3.7 million
3. Interest Costs of \$1.9 million for 2007
- Transmission Costs Recovery
\$1.2 million
 - Energy market Recovery
\$11.9 million
 - Load Settlement Recovery
\$3.7 million
4. Amortization and Depreciation of \$10 million for 2007
- Transmission Costs Recovery
\$4.4 million
 - Energy market Recovery
\$3.3 million
 - Load Settlement Recovery
\$2.3 million
5. AESO's Capital Costs of \$5.4 million for 2007
6. AESO's Other Industry Costs of \$5.5 million for 2007
7. AESO's Line Loss Costs of \$196.0 million for 2007
8. AESO's Ancillary Service Costs of \$184.5 million for 2007

The AESO Board resolution approving the above amounts is included in Section 2.9 of this Application.

AESO Deferral Accounts

The AESO is a not-for-profit statutory corporation and provides system access service to customers pursuant to the Act. Rates charged for services provided are specified in the AESO's tariff and are matters regulated by the Board pursuant to sections 30 and 119 of the Act.

The AESO's approved rate methodology includes the use of deferral accounts. Deferral accounts are necessary in order to allow the AESO to recover differences between actual revenues and costs incurred in providing system access service to customers as set out in Section 122 (3) of the Act. The AESO reconciles, on a retrospective basis, the actual costs it has incurred in providing system access service to the revenues recovered in rates for the time period service was actually provided.

The AESO is not requesting interim approval of revenue requirement identified in this document as a result of the implementation of the deferral account process.

AESO 2007 Revenue Requirement Overview

5

The following provides an overview of the basis for the forecast cost components as approved by the AESO Board in the Decision described above, or otherwise, that comprise the 2007 revenue requirement for the purposes of this tariff application.

10

Section 2.1 provides an overview of the 2007 Forecast Revenue Requirement. Sections 2.2 to 2.5 provide comparison tables, and additional information for wires, ancillary services, transmission losses and AESO Own Costs. Sections 2.6 to 2.10 provide additional information. Schedule 2.0 of this Application provides a detailed Revenue Requirement Schedule. Variances are identified in terms of year-to-year comparisons of the 2007 Forecast over the 2006 Approved Forecast.

15

Wires

20

The AESO's 2007 Forecast wires costs are based on each Transmission Facility Owner's ("TFO's") most recent EUB-approved final or interim tariffs. If more current interim or final rates are approved by the Board for any TFO prior to the determination of this Application, the AESO will amend its forecast accordingly. This is consistent with practice in recent years.

Ancillary Services

25

The 2007 Ancillary Services forecast is based on the AESO's forecast of ancillary service volumes, twelve months of recorded ancillary service cost data to August 2006, and an independent commodity price forecast (EDC Volume 6, Issue 24).

30

The 2007 Operating Reserve cost is determined using forecast volumes and twelve months of historical net prices paid to middle of August 2006.

The 2007 TMR forecast is determined by applying forecast volumes and commodity prices to the respective terms of each contract.

35

The 2007 forecasts for Black Start, Under-Frequency Mitigation, Brazeau Fast Ramp, Poplar Hill and ILRAS is determined using forecast volumes and historical or current contract prices paid for each service.

40

For the 2007 Forecast the AESO has included an additional ancillary service, Generation Remedial Action Scheme (GRAS). This service is required to respond to the sudden loss of the Alberta/British Columbia tie line during high exports and is used to stabilize system frequency.

Losses

45

For 2007 Losses, the AESO continues to build on the methodology used in the GTA submissions from 2004 to 2006. The AESO's 2007 Forecast losses costs are determined using the 2004-2006 method, and compared against a historical solution based on the previous 5 years of hourly losses data, load and generation forecasts, dispatch behaviour in

each hour of the last recorded year, and forecast pool prices developed by an independent forecasting company, EDC Associated Ltd.

5 The 2007 losses volumes forecast utilized 2001 to 2006 actual settlement volumes resulting in an anticipated reduction in forecast losses volumes for 2007. Additionally, the load forecast used for the 2006 loss forecast included a portion of industrial load whose contribution to total system losses was overstated, and monitoring of actual losses confirms the total system losses are not increasing as quickly as previously forecast.

10 Own Costs

The 2007 Own Costs Forecast is determined based on a detailed analysis of specific cost categories. In addition, consideration was given to input received from the BRP in respect of the 2006/2007 and 2007/2008 AESO budget process.

15 **2006 Approved Forecast**

20 The 2006 approved Forecast Revenue Requirement is as filed in the AESO Second Refiling of the 2005-2006 General Tariff Application on December 9, 2005. The Revenue Requirement for 2006 of \$759.0 million was approved in EUB Order U2005-464 on December 20, 2005.

25 On January 13, 2006, the AESO filed an updated 2006 Own Costs forecast with variance explanations, which in aggregate were \$0.2 million less than the approved 2006 forecast amounts. Variance explanations are provided for 2006 “updated” forecast and approved forecast amounts for the Own Costs portion of this application.

30 Construction of a new System Coordination Centre began in September 2005. In addition to the costs incurred for this project in 2005 of \$2.1 million, costs of \$11.6 million are projected to occur in 2006. This allocation was inadvertently omitted in the January 13, 2006 AESO Own Cost Update, but is included in this Application.

2.1 Summary of Revenue Requirement

The 2007 Forecast Revenue Requirement is expected to increase by \$113.7 million as compared to the 2006 Updated Forecast. A summary of these costs is provided in Table 2.1.1 below.

Table 2.1.1 Summary of AESO Revenue Requirement (\$M)

	Sch 2.0 Ref.	2007 Forecast	2006 Approved & Updated Forecast	Variance Under (Over)
Wires Costs	L17	445.2	439.5	(5.7)
Ancillary Services	L37	184.5	150.6	(33.9)
Losses	L40	196.0	131.0	(65.0)
AESO Own Costs	L61	46.8	37.7*	(9.1)
Revenue Requirement	L62	872.5	758.8	(113.7)

* AESO Own Costs reflect forecasts as filed in Application No. 1420890 "AESO 2006 Own Costs Update"

The AESO anticipates an increase in Wires Costs of \$5.7 million relative to the 2006 Forecast. The 2007 wires forecast is based on the most recent EUB Approved Final or Interim TFO wires tariffs. While the AESO is responsible for transmission system planning, and assigns capital projects other than capital maintenance to TFOs, the annual charges to the AESO by TFOs are subject to separate approvals by the EUB and the reasonableness of those charges is not within the scope of this Application.

2007 Ancillary Services costs are forecast to increase by \$33.9 million over 2006, to \$184.5 million, primarily due to an increase in Operating Reserve Costs.

The variance in losses costs from 2006 to 2007 is primarily due to an increase in the pool price from the 2006 Forecast of \$41.20/MWh to a 2007 Forecast of \$66.89/MWh. Although there is a decrease in losses volumes from 3,180 GWh in 2006 to 2,897 GWh (\$7.0 million), there is a net increase of \$65.0 million in losses costs from the 2006 Update to the 2007 forecast.

The 2007 forecast for AESO Own Costs is \$9.1 million (or 24.1%) more than the 2006 Forecast, as a result of higher amortization and depreciation costs, as well as staff and benefits costs, offset by a decrease in external regulatory consulting costs.

Table 2.1.2 Commodity Prices

	2007 Forecast	2006 Approved Forecast	Variance Under (Over)	2005 Actual	2005 Approved Forecast	Variance Under (Over)
Average Pool Price (\$/MWh)	66.89	41.20	(25.69)	70.36	59.92	(10.44)
Average Gas Price (\$/GJ)	8.48	5.80	(2.68)	8.27	6.81	(1.46)
Average Market Heat Rate (GJ/MWh)	7.9	7.1	(0.8)	8.5	8.8	0.3

Forecasts Provided by EDC Associates Ltd.

Schedule 2.0: 2007 Phase I Revenue Requirement Schedule (\$ millions)

**AESO PHASE I REVENUE REQUIREMENT
(\$ MILLIONS)**

Line No.		2007 Forecast	2006 Approved Forecast	Variance Under (Over)	2005 Actual	2005 Approved Forecast	Variance Under (Over)	2004 Actual
	WIRES							
	TFO's Wires-Related Costs							
1	AltaLink	193.7	193.7	-	177.9	181.5	3.6	162.9
2	ATCO Electric Ltd.	166.4	161.2	(5.2)	161.2	161.2	-	154.1
3	Isolated Generation	(7.9)	(3.5)	4.4	(5.9)	(5.5)	0.4	(4.8)
4	Subtotal ATCO Costs	158.5	157.7	(0.8)	155.3	155.7	0.4	149.3
5	Enmax Power Corporation	34.7	33.6	(1.1)	34.1	33.6	(0.5)	32.9
6	EPCOR Transmission Inc.	38.1	32.8	(5.3)	32.8	35.2	2.4	32.8
7	City of Lethbridge	4.4	4.5	0.1	4.5	4.5	-	4.5
8	TransAlta	3.7	3.7	-	3.7	3.6	(0.1)	0.6
9	Refund to the AESO	-	-	-	-	-	-	-
10	Subtotal TransAlta Costs	3.7	3.7	-	3.7	3.6	(0.1)	0.6
11	City of Red Deer	1.7	1.8	0.1	1.8	1.8	-	1.8
12	FortisAlberta Networks (Farm)	1.9	1.9	-	1.9	1.9	-	1.9
13	Subtotal TFO Wires-Related Costs	436.7	429.8	(6.9)	412.1	417.8	5.7	386.8
	Non-Wires Costs							
14	Invitation to Bid on Credits (IBOC)	1.7	2.0	0.3	1.7	1.9	0.2	2.1
15	Location Based Credit Standing Offer (LBC SO)	6.8	7.7	0.9	4.1	7.5	3.4	5.7
16	Subtotal IBOC/LBC SO Costs	8.5	9.7	1.2	5.9	9.4	3.5	7.8
17	TOTAL WIRES COSTS	445.2	439.5	(5.7)	418.0	427.2	9.2	394.6
	ANCILLARY SERVICES							
	Operating Reserves							
	Active							
18	Regulating	34.7	24.8	(9.9)	38.6	27.0	(11.6)	25.1
19	Spinning	41.1	25.6	(15.5)	44.1	29.2	(14.9)	25.7
20	Supplemental	32.0	20.9	(11.1)	30.9	15.1	(15.8)	11.1
21	Subtotal Active Reserves	107.8	71.4	(36.4)	113.5	71.3	(42.2)	61.9
	Standby							
22	Regulating	4.6	7.6	3.0	3.6	4.2	0.6	2.8
23	Spinning	5.7	4.3	(1.4)	5.2	7.0	1.8	4.4
24	Supplemental	3.1	2.1	(1.0)	2.2	1.9	(0.3)	1.3
25	Subtotal Standby Reserves	13.4	14.0	0.6	10.9	13.1	2.2	8.5
26	Trading fees & other related charges				(2.2)		2.2	(1.2)
27	Subtotal Operating Reserves	121.2	85.3	(35.9)	122.2	84.4	(37.8)	69.2
	Other Ancillary Services							
28	Brazeau Fast Ramp (previously GRAS)	0.6	0.4	(0.2)	0.5	0.4	(0.1)	0.4
29	Black Start	2.8	2.3	(0.5)	1.6	2.3	0.7	1.0
30	Transmission Must Run (TMR)	50.8	53.2	2.4	56.2	41.4	(14.8)	43.5
31	Under Frequency Mitigation	5.9	6.9	1.0	6.3	6.5	0.2	6.9
32	Subtotal Other Ancillary Services	60.2	62.8	2.6	64.6	50.6	(14.0)	51.8
	Poplar Hill/ILRAS							
33	Poplar Hill	1.9	1.9	-	1.9	1.9	-	1.9
34	Interruptible Load Remedial Action Scheme (ILRAS)	0.7	0.5	(0.2)	0.8	0.8	-	0.5
35	Generator Remedial Action Schemes	0.5	-	(1.0)	-	-	-	-
36	Subtotal Poplar Hill/ILRAS	3.1	2.4	(0.7)	2.8	2.7	(0.1)	2.4
37	TOTAL ANCILLARY SERVICES	184.5	150.6	(33.9)	189.6	137.7	(51.9)	123.3
	LOSSES							
38	Pool Payment	196.0	131.0	(65.0)	201.8	181.0	(20.8)	142.2
39	Prior Year Losses Adjustments	-	-	-	-	-	-	-
40	TOTAL LOSSES COSTS	196.0	131.0	(65.0)	201.8	181.0	(20.8)	142.2

Schedule 2.0: 2007 Phase I Revenue Requirement Schedule (\$ millions)

**AESO PHASE I REVENUE REQUIREMENT
(\$ MILLIONS)**

Line No.	2007 Forecast	2006 Update	Variance Under (Over)	2005 Actual	2005 Approved	Variance Under (Over)	2004 Actual	
OTHER INDUSTRY COSTS								
41								
	External Regulatory Costs	1.1	2.3	1.2	2.6	5.0	2.4	2.3
42								
	Western Electricity Coordinating Council (WECC)	2.2	1.4	(0.8)	1.0	1.0	-	0.8
43								
	Share of EUB Overhead	2.2	1.8	(0.4)	1.7	1.8	0.1	1.8
44								
	TOTAL OTHER INDUSTRY COSTS	5.5	5.5	(0.0)	5.3	7.8	2.5	5.0
GENERAL AND ADMINISTRATIVE COSTS								
Administrative Costs								
45								
	Staff and Benefits	24.3	19.9	(4.4)	19.7	19.2	(0.5)	16.1
46								
	Consultants	3.3	2.1	(1.2)	2.6	2.6	-	3.5
47								
	Board Members Fees	0.4	0.4	-	0.4	0.3	(0.1)	0.3
48								
	Travel and Training	1.1	1.0	(0.1)	0.8	1.0	0.2	1.0
49								
	Legal	0.4	0.4	-	0.6	0.4	(0.2)	0.4
50								
	Audits/Reviews	0.4	0.2	(0.2)	0.2	0.3	0.1	-
51								
	Rent	1.9	1.5	(0.4)	1.2	1.2	-	0.9
52								
	Insurance	0.4	0.4	-	0.4	0.5	0.1	0.3
53								
	Other Administrative Costs	1.5	1.3	(0.2)	0.9	1.1	0.2	2.2
54								
	Telecomm and IT Maintenance	2.1	1.6	(0.5)	1.4	1.5	0.1	-
55								
	Interconnection Fees (offset)	(0.2)	0.0	0.2	(0.6)	(0.9)	(0.3)	-
56								
	Total Administrative Costs	35.7	28.8	(6.9)	27.6	27.2	(0.4)	24.9
General Costs								
57								
	Interest	1.2	0.5	-	0.4	0.3	(0.1)	0.2
58								
	Amortization and Depreciation	4.4	2.9	(1.5)	2.3	1.7	(0.6)	1.6
	Taxes	-	-	-	-	-	-	(0.4)
59								
	Total General Costs	5.6	3.4	(1.5)	2.7	2.0	(0.7)	1.4
60								
	TOTAL GENERAL & ADMINISTRATIVE COSTS	41.3	32.2	(9.1)	30.3	29.2	(1.1)	26.3
61								
	Total G&A and Other Industry Costs	46.8	37.7	(9.1)	35.6	37.0	1.4	31.3
62								
	TOTAL REVENUE REQUIREMENT	872.5	758.8	(113.7)	844.5	782.9	(61.6)	691.4
CAPITAL								
63								
	General Capital	4.2	3.6	(0.6)	3.8	4.5	0.7	11.3
64								
	System Coordination Centre*	-	11.6	11.6	2.1	-	(2.1)	0.2
65								
	Total Capital	4.2	15.2	11.0	5.9	4.5	(1.4)	11.5

5

* The \$11.6M allocated to the System Coordination Centre in 2006 was not included in the January 13, 2006 AESO Own Cost Update

Note: Totals in this schedule and subsequent schedules and tables may be different due to rounding

2.2 Wires - TFO Wires-Related Costs

Table 2.2.1 TFO Wires-Related Costs (\$M)

Transmission Facility Owner	2007 Forecast	2006 Approved Forecast	Variance Under (Over)	2005 Actual	2005 Approved forecast	Variance Under (Over)
AltaLink Management Ltd.	193.7	193.7	-	177.9	181.5	3.6
ATCO Electric Ltd.	166.4	161.2	(5.2)	161.2	161.2	-
Isolated Generation	(7.9)*	(3.5)	4.4	(5.9)	(5.5)	0.4
Subtotal	158.5	157.7	(0.8)	155.3	155.7	0.4
ENMAX Power Corporation	34.7	33.6	(1.1)	34.1	33.6	(0.5)
EPCOR Transmission Inc.	38.1	32.8	(5.3)	32.8	35.2	2.4
City of Lethbridge	4.4	4.5	0.1	4.5	4.5	-
TransAlta Utilities Corporation	3.7	3.7	-	3.7	3.6	(0.1)
City of Red Deer	1.7	1.8	0.1	1.8	1.8	-
FortisAlberta Networks (Farm)	1.9	1.9	-	1.9	1.9	-
TFO Wires-Related Costs (\$M)	436.7	429.8	(6.9)	412.1	417.8	5.7

5

* ATCO Electric's Isolated Generation forecasted fuel costs of \$8.2 million in 2005 and \$7.9 million in 2006 related to the operation of isolated generating power plants. The EUB approved these forecast fuel costs in EUB Decision 2006-024 on March 17, 2006.

5 The 2007 TFO Wires-Related Cost forecast is based upon the most recent Board-approved Approved Final or Interim Tariffs applicable for the 2006 and 2007 calendar years, or the most recent year available. The 2007 Forecast is \$436.7 million which represents an increase of \$6.9 million from the 2006 Forecast of \$429.8 million.

AltaLink Management Ltd.

10 The AESO's Forecast for AltaLink's 2007 Wires Cost is \$193.7 million, which is identical to the 2006 Forecast. The 2007 Forecast is based on EUB Decision 2005-082 and represents the \$16.1 million monthly charge that was approved by the EUB for the period of January 1, 2006 to December 31, 2006. The 2006 Forecast is based on this same Decision, and was submitted by the AESO in its Second Refiling on December 9, 2005.

ATCO Electric Ltd.

15 The ATCO Electric 2007 Forecast of \$166.4 million is based on its 2006 Interim Approved Tariff in Decision 2005-133 and represents an increase of \$5.2 million from the 2006 previously Approved Forecast of \$161.2 million, which was based on EUB Decision 2005-102.

20 In EUB Decision 2006-024, the Board approved ATCO Electric's forecast fuel costs for isolated generation in the amount of \$7.9 million for 2006. As such, this amount has been used as a placeholder for 2007 Isolated Generation costs. The Board also noted that there are potential variations in fuel costs, and approved AE's Isolated Generation Deferral Account for this amount

ENMAX Power Corporation

30 Commencing January 1, 2006, the EUB assumed responsibility for approving ENMAX's revenue requirement. Prior to this, the Alberta Department of Energy (ADOE) was responsible for approving ENMAX's costs. The EUB has not approved ENMAX's revenue requirement for 2007. Therefore, the 2007 Forecast Wires Cost is based on the last approved revenue requirement of \$33.6, as directed in EUB Rates Order U2005-445, approving the 2006 Interim Tariff.

EPCOR Transmission Inc.

40 The EPCOR 2007 Forecast of \$38.1 is based on its 2006 Interim Approved Tariff per EUB Decision 2005-140, and represents an increase of \$5.3 million compared to the 2006 Forecast of \$32.8 million, which was based on EPCOR's 2005 Interim Approved Tariff in EUB Rates Order U2004-418.

City of Lethbridge

45 Commencing January 1, 2006, the EUB assumed responsibility for approving the City of Lethbridge's revenue requirement.

In Decision 2005-148, the EUB issued interim approval of the City of Lethbridge's 2007 tariff of \$4.4 million. This represents a decrease of \$0.1 million from the 2006 Forecast of \$4.5

million. The City of Lethbridge's 2007 Revenue Requirements were subsequently directed in EUB Rate Order U2006-47.

TransAlta Utilities Corporation

5

The AESO's Forecast for TransAlta's 2006 Wires Cost is \$3.7 million, which is the same as the 2006 Forecast. The 2007 Forecasts are based Decision 2005-082.

The City of Red Deer

10

Commencing January 1, 2006, the EUB assumed responsibility for approving the City of Red Deer's revenue requirement.

15

In Decision 2005-149, the EUB issued an interim approval of the City of Red Deer's 2007 tariff of \$1.8 million. There is no variance from the 2006 Forecast, which was based on the ADOE's 2005 approved Revenue Requirement. In compliance with Decision 2005-149, the City of Red Deer refiled their 2007 Revenue Requirement, which was subsequently approved in EUB Rate Order U2006-48.

20

FortisAlberta Networks (Farm)

FortisAlberta's forecast pertains to farm wires costs. For the purposes of this Application, the 2007 Forecast is \$1.9 million, based on the amounts approved in Decision 2005-007, which granted FortisAlberta permission to initiate a Negotiated Settlement Process.,

25

2.2.1 Non-Wires Costs

Invitation to Bid on Credits Agreements (IBOC) and Location Based Credit Standing Offer Agreements (LBC SO) are included in the AESO's total Wires Costs forecast amount for rate setting purposes. Although these are two separate programs, both were initiated as an incentive for supply to locate closer to major load centres and provide a non-wires solution to transmission wires issues in Alberta.

The 2007 Non-Wires cost forecast is \$8.5 million, which represents a decrease of \$1.2 million from the 2006 Forecast of \$9.7 million. The 2005 Actual Non-Wires cost is \$5.8 million, which represents a decrease of \$3.6 million from the 2005 Forecast of \$9.4 million.

Invitation to Bid on Credits Agreements (IBOC)

	2007 Forecast	2006 Forecast	Variance Under (Over)	2005 Actual	2005 Approved forecast	Variance Under (Over)
IBOC Costs (\$M)	1.7	2.0	0.3	1.7	1.9	0.2

The IBOC program provides a financial credit to a specific generator in the Calgary vicinity based on the volume of megawatt-hours generated each month.

The AESO generally expects costs for the IBOC contract to remain relatively stable as unit operation and contract payments are fairly predictable. The 2005 Actual cost of \$1.7 million is \$0.2 million (or 10.5%) less than the 2005 Forecast of \$1.9 million due to the small decrease in recent availability of the service.

Location Based Credit Standing Offer Agreements (LBC SO)

	2007 Forecast	2006 Forecast	Variance Under (Over)	2005 Actual	2005 Approved Forecast	Variance Under (Over)
LBC SO Costs (\$M)	6.8	7.7	0.9	4.1	7.5	3.4

The LBC SO program provides increased system security, whereby the AESO retains dispatch rights to location-specific generation in return for location-based credits. Those credits are made up of fixed and variable payments.

The variable payment the AESO makes is based upon keeping the generator whole up to an established heat rate (gas price multiplied by heat rate) when dispatched for system security, in the event the market heat rate (pool price divided by gas price) is below the established heat rate. If a provider is dispatched to provide service, and the market heat

rate is above the established heat rate, no variable cost is incurred. The relationship between variable costs, market heat rate and gas price generally are:

- The lower the market heat rate, the higher the variable costs;
- The higher the market heat rate, the lower the variable costs;
- The lower the gas price, the lower the variable cost; and
- The higher the gas price, the higher the variable cost.

The fixed payment the AESO makes to a provider does not change with heat rates, gas price or usage but allows the AESO to call upon the facility for system security, if required.

In EUB Decision 2005-096 the Board reconfirmed the continued obligation of the AESO to fulfill the following directions:

“The Board directs the AESO to report the amount of any amounts received from a generation facility owner (GFO) pursuant to an LBC SO Entitlement offer and to consider such amounts as a offset to the forecast revenue requirement of future general tariff applications in respect of years in which the AESO may be receiving such revenue from a GFO” (pg. 89 – 90)

The AESO requests relief on the ongoing nature of this direction. The AESO suggests that the intent of the direction was to monitor income associated with Eligibility Payments, however these payments would be one time occurrences, and would not be ongoing. The intent of Eligibility Payments was to incent GFOs to achieve COD (Commercial Operation Date) by the RCOD (Required Commercial Operation Date). The Commercial Operation dates, or Commissioning, of facilities has passed. There were no instances of GFOs failing to achieve COD.

“The Board directs the AESO to file with the Board, at the conclusion of each fiscal year, the total number of times conscripted ancillary services were procured as well as the total cost incurred. The number and length of occurrences by payment option and the total cost by payment option should be included.” (pg. 90)

In a single year the AESO enters into tens of thousands of operating reserve transactions. In 2006 (YTD) the AESO has conscripted operating reserves 29 times. Approximately half of these occurrences were due to contracted operating reserve providers being unable to provide their contracted volumes due to unplanned operational problems and the AESO therefore having to conscript (non-contracted) operating reserve providers. The other half of these occurrences are due to delayed communications, generally as a result of system conditions, to contracted operating reserve providers, that results in a contracted operating reserve provider providing service beyond the top of the hour. All operating reserve contracts should expire at the top of the hour.

The AESO has not yet received invoices for the majority of these 29 events. The AESO will be following up with each of the providers to settle these outstanding amounts. The AESO estimates the total cost for the conscriptions to be less than \$20,000. Given the small amount of dollars associated with conscripted operating reserves, (relative to total operating reserve costs of tens of millions) the AESO does not forecast conscripted operating reserve amounts.

5 Since January 1, 2006 the AESO has been conscripting TMR service from one TMR service provider. The AESO is in negotiations with this one service provider to resolve the outstanding conscriptions.

In 2005, the AESO conscripted operating reserves 70 times. The total cost of the conscripted services was approximately \$40,000.

10 *“In order to understand the performance of GFOs and the AESO, the Board directs AESO in all future GTAs for the term of the LBC SO contracts to report on any occurrences where the GFO exceeded the maximum time to commercial operation requirement”. (pg. 90)*

15 There have been no instances where a GFO has exceeded the maximum time to commercial operation.

The 2007 Forecast for LBC SO is \$6.8 million, which is \$0.9 million less than the 2006 Forecast of \$7.7 million. Although there is a forecasted increase in gas price and a decrease in market heat rate, the volumes forecast for LBC SO has decreased.

20 The 2005 Actual cost for LBC SO is \$4.1 million or \$3.4 million less than the 2005 Approved Forecast of \$7.5 million. This is due to significantly lower volumes in 2005 versus the forecast and a low availability in 2005 of one of the three LBC SO facilities, which resulted in the AESO not having to make the fixed payments for most of the year to this one facility.

2.3 Ancillary Services

Table 2.3.1 Summary of Ancillary Services (\$M)

	2007 Forecast	2006 Approved Forecast	Variance Under (Over)	2005 Actual	2005 Approved Forecast	Variance Under (Over)
Operating Reserves (not incl. Trading fees & related charges)	121.2	85.3	(35.9)	124.4	84.4	(40.0)
Transmission Must Run	50.8	53.2	2.4	56.2	41.4	(14.8)
Other Ancillary Services	12.5	12.0	(0.5)	11.2	11.9	0.7
Total Ancillary Services (\$M)	184.5	150.6	(33.9)	191.8	137.7	(54.1)

5

The AESO is responsible for the procurement of Ancillary Services (“AS”) necessary for the secure and reliable operation of the Alberta Interconnected Electric System (“AIES”).

10

Ancillary Services costs are forecast to increase in 2007 by \$33.9 million from the 2006 Approved Forecast of \$150.6 million, to the 2007 Forecast of \$184.5 million. This is due to the large increase in operating reserve costs and smaller increases in TMR and Other Ancillary Service costs. The forecasts provided in this section were reviewed via the ABRP and approved by the AESO Board.

15

2.3.1 Operating Reserves

Table 2.3.1.1 Summary of Operating Reserve Costs (\$M)

	2007 Forecast	2006 Approved Forecast	Variance Under (Over)	2005 Actual	2005 Approved Forecast	Variance Under (Over)
Active Reserves	107.8	71.4	(36.4)	113.6	71.3	(42.2)
Standby Reserves	13.4	14.0	0.6	10.9	13.1	2.2
Total Operating Reserve Costs	121.2	85.3	(35.9)	124.4	84.4	40.0

20

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

The 2007 Forecast for Operating Reserves is \$121.2 million, which is \$35.9 million (or 42.1%) more than the 2006 Forecast of \$85.3 million.

Active Operating Reserves

5

Active Operating Reserves are the operating reserves that are forecast by the AESO as necessary to operate the AIES securely and meet the AESO's reliability obligations to the WECC.

10

The 2007 Forecast for Active Reserves is \$107.8 million, which is \$36.4 million (51.0%) more than the 2006 Forecast of \$71.4 million. The increase in the 2007 Forecast is due to the large increase in operating costs observed in the second half of 2005, where pool price and procured volumes increased.

15

The 2007 Forecast volumes for Active Operating Reserves is comparable to the 2006 Forecast. The slightly lower number in 2007 is caused by more imports in 2007 than 2006. Imports requires less Regulating Reserve than generation.

Standby Reserves

20

Standby Reserves are additional reserves 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 capability.

25

Payments for Standby Reserves include a premium for the option to activate the Standby Reserves and a price that is paid if the reserves are activated. Forecast volumes and prices for premiums and activation charges for each type of Standby Reserve are detailed in the tables below.

30

The 2007 Forecast for Standby Reserves is \$13.4 million, which is \$0.6 million (or 4.3%) less than the 2006 Forecast of \$14.0 million. The difference arises from a revision to the forecast methodology for Standby Reserves from 2006 to 2007. The 2006 methodology assumed an increase in regulating reserve activations as more intermittent generation is anticipated to be online in 2006.

35

2.3.4 Other Ancillary Services

Table 2.3.4 Summary of Other Ancillary Services

Other Ancillary Services	2007 Forecast	2006 Updated Forecast	Variance Under (Over)	2005 Actual	2005 Approved Forecast	Variance Under (Over)
Brazeau Fast Ramp	0.6	0.4	(0.2)	0.5	0.4	(0.1)
Black Start	2.8	2.3	(0.5)	1.6	2.3	0.7
Transmission Must Run (TMR)	50.8	53.2	2.4	56.2	41.4	(14.8)
Under Frequency Mitigation	5.9	6.9	1.0	6.3	6.5	0.2
Poplar Hill	1.9	1.9	-	1.9	1.9	-
Interruptible Load Remedial Action Scheme (ILRAS)	0.7	0.5	(0.2)	0.8	0.8	-
Generation Remedial Action Scheme (GRAS)	0.5	-	(0.5)	-	-	-
Total Other Ancillary Services	63.3	65.2	2.1	67.4	53.3	(14.1)

5

The remaining services that the AESO procures for the secure and reliable operation of the AIES are “Other Ancillary Services”. These services are procured either through competitive processes or bilateral contract negotiations with one or more suppliers, and include Brazeau Fast Ramp (BFR), Black Start, Transmission Must-Run, Under-Frequency Mitigation, Poplar Hill, Interruptible Load Remedial Action Scheme (ILRAS) and Generation Remedial Action Scheme (GRAS).

10

The 2007 Forecast for Other Ancillary Services is \$63.3 million, which is \$2.1 million (or 2.9%) less than the 2006 Forecast of \$65.2 million, primarily due to lower TMR costs, offset by the inclusion of the 2007 forecast for GRAS.

15

Brazeau Fast Ramp (BFR)

This service was identified as Generation Remedial Action Scheme (“GRAS”) in previous GTAs.

20

The 2007 Forecast for the BFR service is \$0.6 million, which is \$0.2 million (or 50.0%) higher than the 2006 Forecast of \$0.4 million, due to the AESO having negotiated an extension to the contract in 2005 with higher pricing.

25

Black Start

5 The 2007 Forecast for Black Start service is \$2.8 million, which is \$0.5 million (or 21.7%) higher than the 2006 Forecast of \$2.3 million. The forecasts for Black Start services are determined based on pricing in existing agreements and historical pricing under expired agreements. The 2007 Forecast uses recent contract information.

Transmission Must-Run (TMR)

10 The 2007 Forecast for TMR is \$50.8 million, which is \$2.4 million (or 4.5%) less than the 2006 Forecast of \$53.2 million. This decrease is due to the decline in forecast market heat rates, offset by higher gas prices and the inclusion of additional costs related to the Rossdale TMR contract. The AESO is now responsible for additional natural gas fuel supply charges that were not contemplated in the 2006 GTA forecast. However, offsetting this, the
15 AESO forecasts fewer TMR agreements in 2007 and structural changes to some of its TMR agreements.

Under-Frequency Mitigation

20 The 2007 Forecast of \$5.9 million is \$1.0 million (or 14.5%) less than the 2006 forecast of \$6.9 million due to the pricing of competitive contracts entered into as a result of the 59.5 Hz Load Shed Service Request for Proposal (“LSS RFP”) in 2005.

Poplar Hill

25 The 2007 Forecast and 2006 Forecast are the same. The Poplar Hill costs are largely fixed and the forecast for these costs is unchanged.

Interruptible Load Remedial Action Scheme (ILRAS)

30 The 2007 Forecast and 2006 Forecast are comparable due to the fixed pricing in the contract which varies slightly based on usage.

Generation Remedial Action Scheme (GRAS)

35 For the 2007 Forecast, the AESO has included an additional ancillary service, Generation Remedial Action Scheme (GRAS). This service is required to respond to the sudden loss of the Alberta/British Columbia tie line during high exports and is used to stabilize system frequency. This service requires a generator to trip off instantaneously in the event a
40 system contingency occurs. The AESO does not procure this service at this time, but expects to have the service contracted for by 2007. Until such time as the forecasted tripping of the service is established, the AESO does not have a reliable forecast of GRAS costs. The 2007 Forecast of \$0.5 million is a place holder estimate not derived using any
45 particular methodology.

2.4 Transmission Losses (Losses)

Table 2.4.1 Transmission Losses Costs (\$M) & Volumes (GWh)

	2007 Forecast	2006 Updated Forecast	Variance Under (Over)	2005 Actual	2005 Approved Forecast	Variance Under (Over)
Total Losses Costs (\$M)	196.0	131.0	(65.0)	201.8	181.0	(20.8)
Total Volumes (GWh)	2,897	3,180	283	2,847	2,986	139
Average Hourly Volume (MWh)	330	363	33	325	341	16

5

Total Losses

10 Losses are the MWh of energy lost on the transmission system when power is transmitted from suppliers to loads. Losses are calculated hourly and expressed monthly and annually. 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.

15 The AESO is initially responsible to pay for the cost of Losses and recovers these costs from generators, importers and opportunity service customers through a location specific loss factor applied against generator outputs, and import/opportunity service volumes. Beginning in 2006, the loss factor will be established in accordance with the AESO rules made pursuant to the *Transmission Regulation*. The Losses volume forecast is produced on a monthly and annual basis. The AESO recovers the cost of Losses through charges that are indexed to pool price, consistent with the manner in which the costs are incurred. The forecasts provided in this section were reviewed via the ABRP and approved by the AESO Board.

25 The AESO's 2007 Forecast losses costs are determined using 2004 – 2006 process and compared with a historical solution based on actual loss data. Additionally, load and generation forecasts, dispatch behaviour in each hour of the last recorded year, and forecast pool prices developed by an independent forecasting company, EDC Associated Ltd are utilized.

30 The 2007 losses volumes forecast, utilized 2005 and 2006 actual settlement volumes, and resulted in an anticipated reduction in losses volumes for 2007. Other considerations that have reduced 2007 total losses volumes forecast relative to 2006 include the following:

- The load forecast used for the 2006 loss forecast included a portion of industrial load whose contribution to total system losses was overstated; and
- Monitoring of actual losses confirms the total system losses are not increasing as quickly as forecast.

35

5 While the AESO recovers the cost of losses through charges that are indexed to pool price, the charges also depend on location-specific loss factors which are determined annually based on historical system loading conditions, historical generating unit outputs, and a generic stacking order for generation. Actual system loading conditions, unit outputs, and stacking order will result in revenues other than forecast, and will lead to accumulation of a deferral account balance for losses. The losses deferral account balance will be recovered or refunded through the Losses Calibration Factor Rider E.

10 Losses Costs

15 The 2007 Forecast cost of losses is \$196.0 million, which is \$65.0 million (or 49.6%) greater than the 2006 Forecast of \$131.0 million. This is due to the forecasted increase in the pool price from the 2006 Forecast of \$41.20/MWh to the 2007 Forecast of \$66.89/MWh, an increase of \$25.69/MWh.

Losses Volumes

20 2007 Forecast volumes of 2,897 GWh are 283 GWh lower than the 2006 Forecast of 3,180 GWh, due to industrial load forecast adjustments which had been previously overstated, and includes consideration of historical losses volumes.

2.5 AESO Own Costs

	2007 Forecast	2006 Updated Forecast	Variance Under (Over)	2005 Actual	2005 Approved Forecast	Variance Under (Over)
External Regulatory Costs	1.1	2.3	1.2	2.6	5.0	2.3
WECC	2.2	1.4	(0.8)	1.0	1.0	-
Share of EUB Overhead	2.2	1.8	(0.4)	1.7	1.8	0.1
Total Other Industry Costs	5.5	5.5	-	5.3	7.8	2.5
Staff and Benefits	24.3	19.9	(4.4)	19.7	19.2	(0.5)
Consultants	3.3	2.1	(1.2)	2.6	2.6	-
Board Members Fees	0.4	0.4	-	0.4	0.3	(0.1)
Travel and Training	1.1	1.0	(0.1)	0.8	1.0	0.2
Legal	0.4	0.4	-	0.6	0.4	(0.2)
Audits/Reviews	0.4	0.2	(0.2)	0.2	0.3	0.1
Rent	1.9	1.5	(0.4)	1.2	1.2	-
Insurance	0.4	0.4	-	0.4	0.5	0.1
Other Administrative Costs	1.5	1.3	(0.2)	0.9	1.1	0.2
Telecom and IT Maintenance	2.1	1.6	(0.5)	1.4	1.5	0.1
Interconnection Fees (offset)	(0.2)	0.0	0.2	(0.6)	(0.9)	(0.3)
Total Administrative Costs	35.7	28.8	(6.9)	27.6	27.2	(0.4)
Interest	1.2	0.5	(0.7)	0.4	0.3	(0.1)
Amortization and Depreciation	4.4	2.9	(1.5)	2.3	1.7	(0.6)
Total General Costs	5.6	3.4	(2.2)	2.7	2.0	(0.7)
TOTAL G&A AND OTHER INDUSTRY COSTS	46.8	37.7	(9.1)	35.6	37.0	1.4

5 The AESO's Forecast 2007 General and Administrative and Other Industry Costs are \$46.8 million, which is \$9.1 million greater than the 2006 Budget of \$37.7 million.

10 The most significant variances are anticipated in the Salaries and Benefits and Consulting cost categories. The actual corporate staff vacancy rate is much higher than anticipated and this is forecasted to continue for the remainder of 2006, into 2007. The cost saving achieved in Salaries and Benefits has (and will continue) to be utilized for consulting resources to supplement AESO staff and work on new, previously unanticipated projects.



5 Additionally, the AESO has forecast Interconnection fees of \$0.2 million in 2007. Interconnection fees are collected by the AESO in accordance with Terms and Conditions of the Tariff. The interconnection fees forecast in 2007 is associated with the merchant transmission line process and directly offsets AESO Own Costs.

As described in the introduction to this section, the 2007 forecast AESO Own Costs noted above were reviewed via the ABRP and approved by the AESO Board.

10 The AESO integrates the transmission, energy market and load settlement business functions in order to maximize the benefits accruing from a single corporate operation. This necessitates the allocation of overall costs to the transmission tariff, energy market trading charge and load settlement charge. The AESO 2007 GTA reflects costs as they relate to the regulated (i.e. transmission tariff) aspect. Section 2.8 provides the details in respect of the Cost Allocation Methodology.

15

2.6 AESO Transmission Capital Continuity

(in \$000s)	2005 Actual	2006 Approved	2007 Forecast
Assets			
Opening Balance	12,037	16,152	31,352
Additions	5,898	15,200	4,200
Disposals	(1,783)	-	-
Closing Balance	16,152	31,352	35,552
Accumulated Depreciation			
Opening Balance	4,748	5,217	8,117
Depreciation	2,252	2,900	3,300
Disposals	(1,783)	-	-
Closing Balance	5,217	8,117	11,417
Net Book Value			
Opening Balance	7,289	10,935	23,235
Closing Balance	10,935	23,235	24,135



2.7 Cost Allocation

The AESO's costs are allocated amongst different groups in the organization. The spreadsheet on the following page provides information on these cost allocations.

AESO Cost Allocation
(\$ millions)

= Inputs

= YE Inputs

2007

Line	Allocation Notes	Transmission			Energy Market			Load Settlement			AESO Total		
		Est. % split to Trans	Staff Count Equiv*	Actual Amount (\$)	Est. % split to Ener Mkt	Staff Count Equiv*	Actual Amount (\$)	Est. % split to Load Set	Staff Count Equiv*	Actual Amount (\$)	Total %	Head Count Equiv*	Total Actual Amount (\$)
		(a)	(b)	(c)	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	DIRECT OPERATING GROUPS												
	OPERATIONS & RELIABILITY												
2	System Operations	67%	25.5	3.4	33%	12.5	1.7	0%	0.0	0.0	100%	38.0	5.1
3	Operations Planning	75%	19.5	3.5	25%	6.5	1.2	0%	0.0	0.0	100%	26.0	4.7
4	Commercial	100%	4.0	0.7	0%	0.0	0.0	0%	0.0	0.0	100%	4.0	0.7
5	Subtotal Operations & Reliability		49.0	7.7		19.0	2.9		0.0	0.0		68.0	10.5
	TRANSMISSION												
6	Engineering	100%	19.0	3.4	0%	0.0	0.0	0%	0.0	0.0	100%	19.0	3.4
7	Technical Services	100%	6.0	0.8	0%	0.0	0.0	0%	0.0	0.0	100%	6.0	0.8
8	500kV System Planning	100%	6.0	1.2	0%	0.0	0.0	0%	0.0	0.0	100%	6.0	1.2
9	Regional Planning	100%	16.0	2.6	0%	0.0	0.0	0%	0.0	0.0	100%	16.0	2.6
10	Resource Adequacy	50%	1.5	0.3	50%	1.5	0.3	0%	0.0	0.0	100%	3.0	0.6
11	Subtotal Transmission		48.5	8.3		1.5	0.3		0.0	0.0		50.0	8.6
12	MARKET SERVICES	0%	0.0	0.0	100%	11.0	1.9	0%	0.0	0.0	100%	11.0	1.9
13	REGULATORY	100%	6.0	1.0	0%	0.0	0.0	0%	0.0	0.0	100%	6.0	1.0
14	LOAD SETTLEMENT	0%	0.0	0.0	0%	0.0	0.0	100%	8.0	1.5	100%	8.0	1.5
15	Total Direct Operating Group Costs		103.5	17.0		31.5	5.1		8.0	1.5		143.0	23.6
16	% of Total Direct Staff Count and Oper Costs		72.3%	72.0%		22.1%	21.6%		5.6%	6.4%		100.0%	100.0%
17	CORPORATE SERVICE COSTS												
18	INFORMATION TECHNOLOGY	62%	32.2	7.2	28%	14.6	3.2	10%	5.2	1.2	100%	52.00	11.5
19	CORPORATE INFRASTRUCTURE	72%	41.8	9.8	22%	12.5	2.9	6%	3.7	0.9	100%	58.00	13.5
20	OFFICE LEASE	70%	n/a	1.9	23%	n/a	0.6	7%	n/a	0.2	100%	n/a	2.7
21	Total Corporate Service Costs		74.0	18.8		27.1	6.8		8.9	2.2		110.00	27.8
22	% of Total Corp Services Staff Count and Oper Costs		67.3%	67.7%		24.6%	24.4%		8.1%	7.9%		100.00%	100.00%
23	Total Transmission (L13 + L19)		177.5	35.9									
24	% of Total AESO Staff Count and Oper Costs		70.2%	69.7%									
25	Total Energy Market (L13 + L19)					58.6	11.9						
26	% of Total AESO Staff Count and Oper Costs					23.2%	23.1%						
27	Total Load Settlement (L13 + L19)								16.9	3.7			
28	% of Total AESO Staff Count and Oper Costs								6.7%	7.2%			
29	Total AESO Operating Budget (L13 + L19)											253.0	51.5
30	% of Total AESO Staff Count and Oper Costs											100.0%	100.0%

Allocation Notes

- 1 Allocation determined by AESO management.
- 2 Allocated based on Total Direct Operating Group Costs
- 3 Allocated based on Staff count for Direct Operating and Corporate Service Groups

2.8 Cost Allocation Methodology

Overview

5 The AESO integrates the transmission, energy market and load settlement business
functions in order to maximize the benefits accruing from a single corporate
operation. Due to this operational integration and the three separate cost recovery
mechanisms that are associated with the business functions (transmission tariff,
energy market trading charge and load settlement recovery charge), cost allocations
10 or assignments are required. The AESO's structure is different from a traditional
utility that would have highly specialized core departments (or even separate
companies), and thus require only shared corporate services be allocated between
functions.

15 The following table and descriptions provide the allocation percentages used for
2006 through 2008 based on the business activities in the various departments.

TABLE 3.4.1 – 2006 - 2008 Cost Allocation Percentages

AESO Department	Transmission
DIRECT OPERATING	
500kV System Planning	100%
Regional Planning	100%
Resource Adequacy	50%
Engineering	100%
Technical Services	100%
System Operations	67%
Operations Planning	75%
Commercial	100%
Regulatory	100%
Market Dev & Ops	0%
Load Settlement	0%
SHARED SERVICES	
Corporate Infrastructure ¹	Based on Direct Operating Group Costs
Information Technology ²	62%
Office Lease	Based on AESO Staff Count
CAPITAL	
SCC Building ³	67%

¹ Includes the following departments: Executive Office, AESO Board, Accounting/Settlement & Risk, Information Technology, Customer Relations, Communications /Stakeholder Relations/Human Resources

² Based on 2005 actual allocations

³ Based on the utilization and allocation percentages of the departments occupying the building

IT Capital

Assigned on a project
basis

The following two categories summarize the allocation methodology for operating costs:

5
1) *Directly incurred and assignable to a business function*

For direct operating departments, their activities can be directly associated with one or more of the business functions (transmission, energy market, load settlement) and the allocation percentage is determined by management based upon an assessment of the cost drivers for the department costs on an annual basis.

10
2) *Allocation of costs from centrally managed and shared corporate services*

15
For corporate service departments, the cost allocation is based upon the costs associated with the direct operating groups (discussed in footnote 1 above). This methodology assumes that the business function with the greater costs would contribute to a higher demand for corporate service and therefore be assigned a higher percentage allocation.

20
For corporate IT costs, the allocation is based upon an activity-based analysis in order to better reflect the nature of the underlying costs and the degree of reliance on information systems by the separate business functions.

25
For office lease costs, the number of staff associated with the three business functions is the basis for allocating the costs. This basis is used as an alternative for the amount of square footage which would be difficult to assess. The allocation of costs associated with the new System Coordination Centre are based on the allocation percentages of the departments utilizing the building (IT and System Operations), the amount of space each department is occupying in the facility with an allocation for common area space.

30
The allocation of the AESO's capital expenditures (primarily IT expenditures) is based upon the following principles:

35
1) Capital costs directly incurred for the support of the business function are 100% assigned to that function,

40
2) Capital costs that cannot be specifically identified as supporting one function in isolation (i.e. shared assets) are allocated to the AESO functions based on management judgment, taking into consideration the business/operating activities that will be supported on the systems (hardware and software).

45
Allocation percentages are reviewed by management twice a year. They are first reviewed when the annual forecast is prepared and again at year end when the allocations are finalized based upon actual activities and costs.

The cost allocation methodology is consistent with that used in prior years, although the allocation percentages have changed to reflect the business/operational activities each year.



Section 2.7 provides the detailed calculation of the cost allocation for 2007 based on the G&A forecasts and staff count.



2.9 Certified Copy of Director’s Resolution Excerpt

The following page includes an excerpt taken from a resolution of the AESO Board approving the 2007 budget.

Certified Copy
of an excerpt taken from a Resolution of the
Members of the Independent System Operator,
a corporation incorporated pursuant to the
***Electric Utilities Act* (Alberta), operating as the**
Alberta Electric System Operator

(the “AESO Board”)

I, Larry D. Kram, do hereby CERTIFY THAT I am the duly elected and qualified Secretary of the AESO Board.

I DO FURTHER CERTIFY THAT the following is an excerpt taken from a Resolution that was duly adopted and passed by the AESO Board, at a meeting of the AESO Board, held in Calgary, Alberta on October 19, 2006, at which a quorum was present and acting throughout:

“BE IT RESOLVED THAT the AESO Board approve the AESO’s 2007 Business Plan and Budget ...particulars of which include approving the following

- ii. General & Administrative Costs of \$51.3 million.
 - Transmission Costs Recovery
\$35.7 million.
 - Energy market Recovery
\$11.9 million.
 - Load Settlement Recovery
\$3.7 million.

- iii. Interest Costs of \$1.9 million
 - Transmission Costs Recovery
\$1.2 million.
 - Energy market Recovery
\$0.5 million.
 - Load Settlement Recovery
\$0.2 million.

- iv. Amortization and Depreciation of \$10.0 million.
 - Transmission Costs Recovery
\$4.4 million.
 - Energy market Recovery
\$3.3 million.
 - Load Settlement Recovery
\$2.3 million.

- v. Capital Costs of \$5.4 million.
- vi. Other Industry Costs of \$5.5 million.
- vii. Line Loss Costs of \$196.0 million.
- viii. Ancillary Service Cost of \$184.5 million.”

AND I, Larry D. Kram, of the City of Calgary, in the Province of Alberta, do hereby FURTHER CERTIFY THAT, as of the date hereof, the foregoing Resolution of the AESO Board has not been modified or rescinded and remains in full force and effect.

DATED at Calgary, Alberta this 2nd day of November, 2006.



Larry D. Kram, Secretary



2.10 Insurance Coverage, Premiums and Deductibles

The following table provides summary information on the AESO's insurance coverage, premiums and deductibles.

Alberta Electric System Operator – Insurance Coverage Summary

Policy	2005/2006 Coverage	2005/2006 Deductible	2005/2006 Underwriter	{actual}	{estimate}	{estimate}	2006 Expense	2007 Expense
				July 2005 to June 2006 Premium	July 2006 to June 2007 Premium	July 2007 to June 2008 Premium		
Crime*	\$20 million	\$50,000	Chubb	\$25,300	\$26,565	\$27,893	\$25,933	\$27,229
Directors & Officers	\$10 million	\$50,000	Chubb	\$28,750	\$30,188	\$31,697	\$29,469	\$30,942
Excess Directors & Officers	\$15 million	N/A	ACE-Ina	\$32,085	\$33,689	\$35,374	\$32,887	\$34,531
Commercial General Liability & Professional Liability**	\$50 million	\$500,000	AEGIS	\$378,882	\$416,770	\$458,447	\$397,826	\$437,609
Office Contents & General Liability***	\$21.5 million total insured value (2005/2006), ----- \$35 million (2006/2007) – (estimate)	\$2,500	ECI	\$36,971	\$55,457	\$61,002	\$46,214	\$58,229
Property – terrorism	\$12 million	\$100,000	"London"	\$12,000	\$12,600	\$13,230	\$12,300	\$12,915
			Total Premiums	\$513,988	\$575,268	\$627,643	\$544,628	\$601,456

* 5% increase annually

** 10% increase annually

*** 2006/2007 increase for System Coordination Centre building