



March 12, 2009

Submitted via AUC Digital Data Submission (DDS) System

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

Dear Sir or Madam:

Re: AESO 2009 Rates Update Application

Please find enclosed the 2009 Rates Update Application of the Alberta Electric System Operator (“AESO”), made pursuant to sections 30 and 119 of the Electric Utilities Act, S.A. 2003, c. E-5.1. This application seeks approval by the Alberta Utilities Commission (“AUC”) of an update to the rates to be charged for each class of system access service in the AESO’s currently approved tariff.

The proposed update changes only the levels of the rates (that is, the dollar-based and percentage of pool price charges included in the rate schedules) based on costs and billing determinants forecast by the AESO for the 2009 calendar year. All costs included in the application have already received approval, either by the AUC for transmission facility owner tariffs or by the AESO Board for ancillary services, transmission line losses, and the AESO’s own administration. The application does not include any changes to the structure or methodology used to determine the rates, or to the terms and conditions of service currently approved in the AESO’s tariff.

As explained in more detail in the application, its purpose is to update the AESO’s rates to recover a greater portion of the AESO’s revenue requirement through “base rates”, and to correspondingly reduce the portion recovered through deferral account Rider C. The rates update will have no effect on the aggregate amount of revenue received by the AESO through base rates, deferral account riders, and deferral account reconciliations. Its only effect will be to recover a greater portion of such revenue through the more precise and timelier mechanism of the AESO’s base rates.

The AESO requests the updated rates be approved to be effective on July 1, 2009 or such other date as the AUC deems appropriate. If the regulatory review process does not permit final approval in time for these rates to be effective on July 1, 2009, the AESO requests that the AUC consider approving these rates on an interim basis to be effective on that date. In any case, the AESO requests that the rates be effective no earlier than the first of the month at least 30 days

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

IN THE MATTER OF an application for Alberta Utilities Commission approval of the rates to be charged by the AESO for each class of system access service.

**Alberta Electric System Operator
2009 Rates Update
Application**

March 12, 2009



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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 Utilities Commission (“AUC”) for a tariff which sets out, among other things, the rates to be charged for each class of system access service.

10 In particular, the application seeks approval of an update to the rates to be charged by the AESO for each class of system access service in its currently approved tariff.

15 The proposed update changes only the levels of the rates (that is, the dollar-based and percentage of pool price charges included in the rate schedules) based on costs and billing determinants forecast by the AESO for the 2009 calendar year. It does not include any changes to the structure of the rates, or to the terms and conditions of service currently approved in the AESO’s tariff.

20 The AESO notes that, for simplicity in this application, references to the AUC include the Alberta Energy and Utilities Board (“EUB”) as its predecessor.

1.1 Background

25 The AESO’s tariff was most recently approved in AUC Order U2008-217 concerning the AESO’s 2007 General Tariff Application (“GTA”) filed on November 3, 2006. The application was reviewed in the following proceedings before the AUC:

- Application No. 1485517 on the 2007 GTA itself,
- Application No. 1558815 on the First Refiling in compliance with Decision 2007-106, and
- Application No. 1572160 on the Second Refiling in compliance with Decision 2008-037.

30 In the original application and throughout the review proceedings, the AESO’s rates were based on the costs and billing determinants forecast by the AESO for the 2007 calendar year. Those rates became effective on August 1, 2008, in accordance with Order U2008-217.

35 The AESO’s currently approved tariff also includes the use of deferral accounts to ensure no annual profit or loss results from the AESO’s operation in accordance with subsection 14(3) 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. The AESO’s tariff accordingly includes Working Capital Deficiency/Surplus Rider B, Deferral Account Adjustment Rider C, and Losses Calibration Factor Rider E, all of which are used to address differences between actual revenues and costs incurred by the AESO.

45 The AESO notes that the reasonable recovery of the cost of transmission system losses is provided through the determination of annual loss factors in accordance with ISO Rule 9.2 and the requirements of sections 31 and 36 of the *Transmission Regulation*, A.R. 86/2007. In addition, Losses Calibration Factor Rider E recovers or refunds differences between



5 actual revenues and costs associated with transmission system losses, in accordance with section 33 of the *Transmission Regulation*. The determination of loss factors, the recovery of the cost of losses, and the application of the Losses Calibration Factor Rider E are not included in this application, and the AESO seeks no direction with respect to those matters. However, the AESO includes the cost of losses in both its forecast revenue requirement and rate calculations, simply for the sake of completeness.

10 Differences between actual revenues and costs for the balance of the AESO's revenue requirement are generally addressed through Deferral Account Adjustment Rider C. Rider C has been used by the AESO since current rates became effective, to recover or refund deferral account balances on a quarterly basis and thereby ensure no annual profit or loss results from the AESO's operation. In addition, the AESO is preparing its 2008 deferral account reconciliation application for filing in April 2009, which will reconcile, on a retrospective basis, the deferral account balances and allocate those balances to
15 customers.

The AESO has not used Working Capital Deficiency/Surplus Rider B to address deferral account balances under the current tariff, although it remains available if required.

20 1.2 Purpose of Application

25 There is no requirement that the AESO update its rates between more comprehensive GTAs, as deferral accounts provide certainty that the AESO can fully recover its costs. Accordingly, the AESO's costs are primarily recovered through approved "base rates", with any shortfall or surplus between actual costs and base rate revenue either recovered or refunded through deferral account riders.

30 However, the recovery or refund of shortfalls or surpluses through deferral account Rider C is imprecise, as the rider is designed on a simple \$/MWh basis. As well, recovery or refund of amounts through Rider C is effectively done on an interim basis, and is "unwound" when deferral account balances are allocated to customers more precisely on a revenue basis in later deferral account reconciliations. If large variances between costs and revenues are addressed through deferral account Rider C, the final allocation to customers in a deferral account reconciliation is subject to greater uncertainty.

35 As well, the deferral account reconciliation application occurs after year-end, several months later than the initial deferral account rider recovery or refund. The deferral account rider process therefore results in timing delays between when costs are incurred to provide system access service and when those costs are finally and accurately recovered from
40 customers.

45 The purpose of this application is to update the AESO's rates to recover a greater portion of the AESO's revenue requirement through base rates, and to correspondingly reduce the portion recovered through Rider C. The rates update will have no effect on the aggregate amount of revenue received by the AESO through base rates, deferral account riders, and deferral account reconciliations. Its only effect will be to recover a greater portion of revenue through the more precise and timelier mechanism of the AESO's base rates.

Table 1-1 2008 Revenue From Base Rates and Riders

Rate Component	Recorded Costs \$ 000 000	Recorded Base Rate Revenue \$ 000 000	Over (Under) Collection \$ 000 000	2008 Riders C and E		Remaining Over (Under) Collection \$ 000 000
				Collected (Refunded) \$ 000 000	Percentage of Costs %	
Interconnection	(\$564.1)	\$494.3	(\$69.8)	\$61.8	(11.0%)	(\$8.0)
Operating Reserve	(264.3)	183.5	(80.8)	83.1	(31.5%)	2.3
Losses	(234.5)	237.6	3.1	(13.7)	5.8%	(10.5)
Voltage Control	(42.1)	52.1	10.0	(9.7)	23.0%	0.3
Other System Support	(6.0)	8.3	2.2	(1.8)	29.0%	0.5
Total	(\$1,111.0)	\$975.7	(\$135.3)	\$119.9	(10.8%)	(\$15.4)
Percentage of Costs	(100.0%)	87.8%	(12.2%)	10.8%	—	(1.4%)

Note: Numbers may not add due to rounding.

5 As an example of the comparative proportions of AESO revenue recovery, Table 1-1 above summarizes the AESO's costs and revenues for 2008 (based on preliminary information prepared for the AESO's upcoming 2008 deferral account reconciliation application). For context, the AESO's rates in effect from January through July 2008 were based on the AESO's 2006 forecast revenue requirement, and the rates in effect from August through
10 December 2008 were based on the AESO's 2007 forecast revenue requirement. In 2008, about 88% of the AESO's actual costs were recovered through base rates, while about 11% were recovered through deferral account Riders C and E. The remaining 1% relates to costs from other years or costs to be addressed through a deferral account reconciliation application. As well, the AESO notes that, on an individual rate component basis, the amounts recovered or refunded through Riders C and E represent as much as 31% of
15 actual costs.

If rates are not updated as proposed in this application, the AESO would expect a similar result for 2009. The AESO's 2009 forecast revenue requirement (detailed in section 2.1 of this application) is \$1,123.9 million. On current rates, the AESO would expect to recover
20 \$991.6 million, or about 88%, through base rate revenue (as detailed on Table 4-11 in section 4 of this application). The remaining 12% would be expected to be recovered through Riders C and E.

25 The AESO suggests that recovery of over 10% of its revenue requirement through deferral account riders is unnecessary, and can be remedied in large part by the rates update proposed in this application. Updating rates to be reflective of current costs minimizes deferral account balances to be recovered through riders, and thereby provides more accurate and timelier recovery of costs from customers. This rates update application was prepared for that purpose.



1.2 Organization of Application

This application is organized into the following sections:

- 5 **1 Application** — Provides background on the application and specifies the relief requested.
- 10 **2 AESO 2009 Forecast Costs** — Summarizes the AESO's forecast revenue requirement for 2009, including costs which have been approved either by the AUC (for transmission facility owner tariffs) or by the AESO Board (for ancillary services, transmission line losses, and the AESO's own administration).
- 15 **3 2009 Rates Update** — Discusses the calculation of rate levels for each AESO rate based on the 2009 forecast revenue requirement, 2009 forecast billing determinants, and the rate calculation methodology approved in AUC Order U2008-217.
- 20 **4 2009 Rates Calculations** — Provides the Microsoft Excel workbook which calculates the updated dollar and percentage of pool price amounts for the 2009 rates, based on the same methodology as used for the AESO's currently approved rates.
- 25 **5 Proposed Rate and Riders** — Provides the actual rates and riders reflecting the 2009 updated dollar and percentage of pool price amounts.
- A AESO Board Decision Appendix** — Approval by the AESO Board issued on January 28, 2009, for forecasted ancillary services costs, forecasted losses costs, and the AESO's business priorities and budget for 2009.
- 30 **B AESO Board Decision Document Appendix** — Submission of AESO management to the AESO Board on September 29, 2008, containing detailed proposals for amendments to the AESO's 2008-2009 business plan and budget as it related to forecasted ancillary services costs, forecasted losses costs, and the AESO's business priorities and budget for 2009.

1.4 Relief Requested

35 This application calculates dollar and percentage of pool price amounts for the AESO's rates which are reflective of those costs which are forecast to be incurred by the AESO in 2009. The application does not request approval of these costs, as all have been subject to their own review and approval processes, either by the AUC or by the AESO Board.

40

The application calculates the updated rates using the same methodology approved in the AESO's 2007 GTA Second Refiling. The application therefore does not request approval of the rate calculation methodology.

45 The application also does not request approval of any aspects of the recovery of the cost of transmission system losses, the determination of annual loss factors, or the determination of Losses Calibration Factor Rider E.



Rather, based on the entirety of this application, the AESO requests:

- 5
- (a) Approval of the updated dollar amounts as calculated for the AESO's 2009 rates as presented in section 4 of this application; and
 - (b) Approval of the rate and rider schedules which reflect these amounts as presented in section 5 of this application.

10 The AESO requests these updated rates be approved to be effective on July 1, 2009 or such other date as the AUC deems appropriate. If the regulatory review process does not permit final approval in time for these rates to be effective on July 1, 2009, the AESO requests that the AUC consider approving these rates on an interim basis to be effective on that date. In either case, the AESO requests that the rates be effective no earlier than the first of the month at least 30 days after the date of the AUC's decision, to allow adequate
15 time to program and test the rates in the AESO's billing system.

20 For additional clarity, the AESO requests these rates apply on a go-forward basis only, on their effective date after approval by the AUC. Notwithstanding the discussion in section 1.2 of this application, the AESO considers it appropriate that currently approved deferral account rider and reconciliation mechanisms be used to address any variances between costs and revenues occurring prior to the approval of the applied-for rates. The AESO is therefore not seeking any retroactivity with respect to the rates proposed for approval in this application.

25 Given the limited scope of the requested approvals, the AESO suggests this application be reviewed through an expedited written proceeding.

All of which is respectfully submitted this 12th day of March, 2009.

30 Alberta Electric System Operator

35 Per: _____
Heidi Kirrmaier
Vice President, Regulatory

2 AESO 2009 FORECAST COSTS

The AESO's revenue requirement consists of costs related to wires, ancillary services, transmission line losses, and the AESO's own administration (which includes other industry costs and general and administrative costs). For 2009, those costs are forecast to total \$1,123.9 million. The AESO's forecast costs for 2009 are detailed in column A of Table 2-2, which for comparison also includes costs for 2008 and 2007 in columns C and D respectively.

The 2009 forecast costs represent an increase of \$238.1 million (26.9%) over the \$885.8 million of total costs on which currently-approved rates were based in the AESO's 2007 GTA Second Refiling. This increase above the basis for current rates is the primary reason for this rates update application.

Section 1.1 of this application explained that any of the AESO's costs which are not recovered through base rates are fully recovered through deferral accounts. Accordingly, as the variance increases between base rate revenue and actual costs, a greater proportion of costs are recovered through deferral account riders and later reconciliations. As summarized in Table 2-1 below, the variances between 2009 forecast and 2007 approved cost components are significant, and range from a 14.2% increase in wires costs to a 70.9% increase in administrative costs.

Table 2-1 2009 Forecast and 2007 Approved Cost Components

Cost Component	2009	2007	Increase (Decrease)	
	Forecast \$ 000 000	Approved \$ 000 000	\$ 000 000	%
Wires	\$523.7	\$458.5	\$65.2	14.2%
Ancillary Services	282.2	184.5	97.7	53.0%
Losses	238.0	196.0	42.0	21.4%
Administrative	80.0	46.8	33.2	70.9%
Revenue Requirement	\$1,123.9	\$885.8	\$238.1	26.9%

Note: Numbers may not add due to rounding

Although deferral account riders and later reconciliations allow the AESO to recover variances between base rate revenue and actual costs, use of deferral accounts generally provides imprecise and delayed allocation of costs to customers as discussed previously in section 1.2. It is therefore reasonable to update rates to reflect significant changes in costs, as in this application.

2.1 AESO Board Approval of Costs

The AESO is not seeking approval in this application of its 2009 forecast revenue requirement. The AESO's forecast costs have been approved through other processes as

Table 2-2 AESO 2009 Forecast Revenue Requirement, \$ 000 000

Line No.	Description	A	B	C	D
		2009 AESO Board Updated TFO Costs	2008 Decision 28 Jan 2009	2008 AESO Board Decision	2007 Approved U2008-217
WIRES					
TFO Wires-Related Costs					
1	AltaLink	235.6	228.7	227.5	208.0
2	ATCO Electric	194.0	178.9	176.6	169.5
3	Isolated Generation	(9.3)	(6.4)	(10.0)	(7.9)
4	Subtotal ATCO Costs	184.7	172.5	166.6	161.6
5	ENMAX Power Corporation	31.9	31.9	31.9	31.9
6	EPCOR Distribution & Transmission	51.7	40.9	36.8	36.8
7	City of Lethbridge	4.5	4.5	4.5	4.4
8	TransAlta Utilities Corporation	4.2	4.2	4.2	4.2
9	City of Red Deer	1.7	1.7	1.7	1.7
10	FortisAlberta (Farm Transmission)	1.9	1.9	1.5	1.5
11	Subtotal TFO Wires-Related Costs	516.2	486.3	474.7	450.0
Non-Wires Costs					
12	Invitation to Bid on Credits (IBOC)	1.6	1.6	1.7	1.7
13	Location Based Credit Standing Offer (LBC SO)	5.9	5.9	7.1	6.8
14	Subtotal IBOC/LBC SO Costs	7.5	7.5	8.8	8.5
15	TOTAL WIRES COSTS	523.7	493.8	483.5	458.5
ANCILLARY SERVICES					
Operating Reserves					
Active					
16	Regulating	59.1	59.1	57.3	34.7
17	Spinning	86.9	86.9	78.7	41.1
18	Supplemental	77.7	77.7	69.4	32.0
19	Subtotal Active Reserves	223.7	223.7	205.4	107.8
Standby					
20	Regulating	6.2	6.2	4.7	4.6
21	Spinning	4.1	4.1	3.6	5.7
22	Supplemental	1.6	1.6	1.4	3.1
23	Subtotal Standby Reserves	11.8	11.8	9.7	13.4
24	Trading fees & other related charges	-	-	-	-
25	Subtotal Operating Reserves	235.5	235.5	215.1	121.2
Other Ancillary Services					
26	Brazeau Fast Ramp (Previously GRAS)	-	-	0.7	0.6
27	Black Start	2.9	2.9	2.0	2.8
28	Transmission Must Run (TMR)	37.2	37.2	40.2	50.8
29	Under Frequency Mitigation	4.5	4.5	5.0	5.9
30	Subtotal Other Ancillary Services	44.7	44.7	48.0	60.2

Table 2-2 AESO 2009 Forecast Revenue Requirement, \$ 000 000 (continued)

Line No.	Description	A	B	C	D
		2009 AESO Board Updated TFO Costs	2008 Decision 28 Jan 2009	2008 AESO Board Decision	2007 Approved U2008-217
Poplar Hill/ILRAS					
31	Poplar Hill	2.1	2.1	1.9	1.9
32	Interruptible Load Remedial Action Scheme (ILRAS)	-	-	0.8	0.7
33	Generator Remedial Action Schemes (RAS)	-	-	-	0.5
34	Subtotal Poplar Hill/ILRAS	2.1	2.1	2.8	3.1
35	TOTAL ANCILLARY SERVICES	282.2	282.2	265.9	184.5
LOSSES					
36	Pool Payment	238.0	238.0	251.4	196.0
37	TOTAL LOSSES COSTS	238.0	238.0	251.4	196.0
OTHER INDUSTRY COSTS					
38	External Regulatory Costs	5.9	5.9	4.1	1.1
39	Western Electricity Coordination Council (WECC)	2.8	2.8	2.5	2.2
40	Share of EUB Overhead	9.9	9.9	2.5	2.2
41	TOTAL OTHER INDUSTRY COSTS	18.6	18.6	9.1	5.5
GENERAL AND ADMINISTRATIVE COSTS					
Administrative Costs					
42	Staff and Benefits	31.8	31.8	28.0	24.4
43	Consultants	9.0	9.0	5.8	3.3
44	Board Members Fees	0.6	0.6	0.5	0.4
45	Travel and Training	1.7	1.7	1.7	1.1
46	Legal	0.8	0.8	0.5	0.4
47	Audits/Reviews	0.6	0.6	0.6	0.4
48	Rent	2.5	2.5	2.0	1.9
49	Insurance	0.4	0.4	0.4	0.4
50	Other Administrative Costs	2.3	2.3	2.4	1.5
51	Telecomm and IT Maintenance	2.5	2.5	2.3	2.1
52	Interconnection Fees (offset)	-	-	-	(0.2)
53	Subtotal Administrative Costs	52.3	52.3	44.2	35.7
General Costs					
54	Interest	1.8	1.8	1.7	1.2
55	Amortization and Depreciation	7.3	7.3	5.8	4.4
56	Subtotal General Costs	9.1	9.1	7.5	5.6
57	TOTAL G&A COSTS	61.4	61.4	51.7	41.3
58	TOTAL G&A AND OTHER INDUSTRY COSTS	80.0	80.0	60.8	46.8
59	TOTAL REVENUE REQUIREMENT	1,123.9	1,094.0	1,061.6	885.8

Table 2-2 AESO 2009 Forecast Revenue Requirement, \$ 000 000 (continued)

Line No.	Description	A	B	C	D
		2009 AESO Board Updated TFO Costs	2008 Decision 28 Jan 2009	2008 AESO Board Decision	2007 Approved U2008-217
CAPITAL					
60	General Capital	5.3	5.3	5.8	4.2
61	System Coordination Centre	-	-	-	-
62	TOTAL CAPITAL	5.3	5.3	5.8	4.2

Note: Numbers may not add due to rounding

5 provided for in relevant legislation. Those costs, as provided in column B of Table 2-2, were addressed in the AESO Board Decision dated January 28, 2009, included as Appendix A to this application. The included costs have been approved through the processes discussed below.

10 (a) Wires-related costs reflect the rates paid by the AESO to transmission facility owners (TFOs) in the TFO tariffs approved by the AUC under section 37 of the EUA. (The wires costs included in the AESO Board Decision reflect TFO tariffs approved by the AUC at the time the AESO budget was prepared in late 2008, as discussed in more detail in section 2.2 below.)

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

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

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

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

35 The practice established by the AESO to carry out consultation on ancillary services, losses, and administrative costs is the Budget Review Process (“BRP”). The BRP is a transparent stakeholder process which provides a prudence review with input from stakeholders. At the

conclusion of the BRP, a recommendation with respect to the ancillary services costs, losses costs, and administrative costs is provided by AESO management to the AESO Board for approval.

5 As part of the AESO BRP for its 2008 and 2009 budgets, AESO management consulted with stakeholders on a multi-year budget process (outlined in more detail in the *AESO Board Decision* which is Appendix A to this application). An abbreviated BRP was also developed in recognition of the need for a process to amend the approved multi-year budgets and to approve annual forecasts of ancillary services and losses costs.

10 AESO management, following consultation with stakeholders and incorporating appropriate amendments arising from the consultation, submitted an AESO Board Decision document to the AESO Board on September 29, 2008. The document (provided as Appendix B to this application) contained detailed proposals for amendments to the AESO's 2008-2009 business plan and budget as it related to forecasted ancillary services costs, forecasted losses costs, and the AESO's business priorities and budget for 2009. The document was also provided to stakeholders and posted on the AESO website. The final AESO Board Decision includes amendments to the forecasted ancillary services and losses costs for 2009 and to the AESO's business priorities and budget for 2009.

20 Additional information on the AESO's business priorities and budget for 2009 is available on the AESO website at www.aeso.ca by following the path About AESO ► Our Business ► Business Plan and Budget ► 2009 Budget Review.

25 **2.2 2009 Wires Costs**

The 2009 forecast cost for wires is \$523.7 million and represents about 47% of the AESO's transmission revenue requirement. Wires costs include primarily TFO wires-related costs as well as two small non-wires costs.

30 The *AESO Board Decision* discussed in section 2.1 above included TFO wires-related costs based on the TFO tariffs approved by the AUC at the time the AESO budget was prepared in late 2008. Those costs are included in column B, lines 1 through 11, of Table 2-2. Most of the TFO tariffs reflected in column B reflect AUC approvals for 2008 or earlier years, those being the most recent years for which final or interim TFO tariff approvals had been issued at the time.

40 The AUC has subsequently issued several final or interim TFO tariff approvals for 2009. The wires costs have therefore been updated in this application to reflect these more recent approvals. The wires costs included in this application are based on the following AUC approvals.

Line 1 AltaLink

45 The 2009 forecast cost for AltaLink TFO is \$235.6 million as approved in AUC Decision 2008-129 released on December 9, 2008 on AltaLink's 2009 Interim Transmission Facility Owner Tariff.

Lines 2-4 ATCO Electric

The 2009 forecast cost for ATCO Electric TFO is \$194.0 million as approved in AUC Decision 2008-134 released on December 19, 2008 on ATCO Electric's 2009 Interim Transmission Facility Owner's Tariff.

5

ATCO Electric's TFO costs are offset by payments to the AESO in respect of pool price for electric energy provided to isolated communities in accordance with the *Isolated Generating Units and Customer Choice Regulation*, A.R. 165/2003. The isolated generation cost offset was estimated at \$9.3 million based on 2008 recorded volumes for isolated communities and the 2009 forecast pool price.

10

The 2009 net forecast cost for ATCO Electric TFO is accordingly \$184.7 million.

Line 5 ENMAX Power Corporation

The 2009 forecast cost for ENMAX Power Corporation TFO is \$31.9 million as approved on an interim basis in AUC Decision 2006-130 released on December 21, 2006 on ENMAX's Refiling of 2006 Transmission Facility Owner Tariff.

15

Line 6 EPCOR Distribution & Transmission

The 2009 forecast cost for EPCOR Distribution & Transmission TFO is \$51.7 million as approved in AUC Decision 2008-125 released on December 3, 2008 on EPCOR's 2007-2009 Transmission Facility Owners Tariff.

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Line 7 City of Lethbridge

The 2009 forecast cost for Lethbridge TFO is \$4.5 million as approved in AUC Order U2008-377 released on December 11, 2008 on Lethbridge's Interim 2009 Transmission Facility Owner Tariff.

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Line 8 TransAlta Utilities Corporation

The 2009 forecast cost for TransAlta TFO is \$4.2 million as approved in AUC Order U2008-367 released on December 4, 2008 on TransAlta's 2009 Interim Transmission Facility Owners Tariff.

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Line 9 City of Red Deer

The 2009 forecast cost for Red Deer TFO is \$1.7 million as approved in AUC Order U2008-378 released on December 11, 2008 on Red Deer's Interim 2009 Transmission Facility Owner Tariff.

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Line 10 FortisAlberta (Farm Transmission)

Section 32 of the EUA requires the AESO to pay owners of electric distribution systems for "farm transmission costs" as defined in the EUA. The 2009 forecast farm transmission cost for FortisAlberta is \$1.9 million as included in the revenue requirement schedules approved in AUC Decision 2008-011 released on February 12, 2008 on FortisAlberta's 2008/2009 Phase I Distribution Tariff and Negotiated Settlement Agreement.

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Lines 12-14 Non-Wires Costs

The AESO includes as wires costs two cost components which are not TFO-related: Invitation to Bid on Credit (IBOC) costs and Location Based Credit Standing Offer (LBC SO) costs. These small amounts are included by the AESO with ancillary services costs approved by the AESO Board.

2.3 2009 Ancillary Services Cost

The 2009 forecast cost for ancillary services is \$282.2 million and represents about 25% of the AESO's transmission revenue requirement. Ancillary services, as defined in the EUA, are services required to ensure that the interconnected electric system is operated in a manner that provides a satisfactory level of service with acceptable levels of voltage and frequency. The largest component of ancillary services costs is operating reserves, which are unloaded generating capacity that is available to respond to temporary shortfalls in supply caused by loss of a generating unit, loss of intertie capacity, or fluctuations in load.

Ancillary services cost is a function of volume forecasts and market-based commodity pricing forecasts. The 2009 forecast cost for ancillary services was based on a forecast average pool price of \$84.43/MWh. (The AESO notes an earlier forecast average pool price of \$84.61/MWh is indicated in the *AESO Board Decision Document* provided as Appendix B to this application. However, a final forecast pool price of \$84.43/MWh was used in the preparation of the ancillary services and losses costs forecasts included in the AESO's final 2009 forecast revenue requirement.)

2.4 2009 Losses Cost

The 2009 forecast cost for transmission line losses is \$238.0 million and represents about 21% of the AESO's transmission revenue requirement as provided in Table 2-2. Losses are the energy lost on the transmission system when power is transmitted from suppliers to loads. Losses are the residual of the metered generation plus scheduled imports less scheduled exports and less metered loads.

Losses cost is a function of volume forecasts and market-based commodity pricing forecasts. The 2009 forecast cost for losses was based on a forecast average pool price of \$84.43/MWh.

2.5 2009 Administrative Costs

The 2009 forecast cost for administration is \$80.0 million and represents about 7% of the AESO's transmission revenue requirement.

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

- 1(1)(g) "ISO's own administrative costs" means
- (i) the transmission-related costs and expenses of the ISO respecting the administration, operation and management of the ISO,

- (ii) *the transmission-related costs and expenses of the ISO respecting reliability standards and reliability management systems, and*
- (iii) *the transmission-related costs and expenses required to be paid, or otherwise appropriately paid, by the ISO, except for the following:*
- (A) *costs for the provision of ancillary services;*
 - (B) *costs of transmission line losses;*
 - (C) *amounts payable under TFO transmission tariffs;*

The AESO Board approves the AESO's administrative costs in their entirety. However, the amounts recovered through the AESO's tariff includes only the transmission-related portions of those costs, in accordance with paragraph 1(1)(g) of the *Transmission Regulation*. The AESO Board approval therefore includes the allocation of administrative costs between the three functions of the AESO, namely, transmission, energy market, and load settlement.

The allocation of the AESO's administrative costs between the three AESO functions is summarized in Table 2-3 below.

Table 2-3 Allocation of Administrative Costs to AESO Functions, \$ 000 000

Administrative Cost Component	Total	AESO Function		
		Transmission	Energy Market	Load Settlement
Other Industry Costs	\$25.8	\$18.6	\$7.2	\$ -
Administrative Costs	69.7	52.3	14.9	2.4
General Costs	15.9	9.1	4.4	2.5
Total Administrative Costs	\$111.4	\$80.0	\$26.5	\$4.9

Note: Numbers may not add due to rounding

Only the transmission-related portions of the AESO's administrative costs are included in the AESO's transmission revenue requirement detailed in Table 2-2.



3 2009 RATES UPDATE

5 The AESO's rates calculations were most recently approved as part of its 2007 GTA, which included a comprehensive examination of the approach and methodology used to establish the AESO's rates. In this rates update application, the AESO does not propose any change to the functionalization, classification, and allocation of the AESO's revenue requirement as approved in AUC Order U2008-217 released on June 25, 2008, nor to any of the responses to specific directions issued by the AUC as part of the 2007 GTA proceeding with respect to the design and structure of the AESO's rates.

10 The AESO has simply calculated the rate levels for each AESO rate based on the 2009 forecast revenue requirement discussed in section 2 of this application, using the rate calculations approved in AUC Order U2008-217. More specifically, the AESO has used the rate calculations attached as Schedules Comm.AESO-001 (h)-B-5.1 through B-5.13 to the response to Information Request Comm.AESO-001 (h), filed on March 26, 2008 in the AESO's 2007 GTA Refiling proceeding.

15 The 2009 updated rate calculations are detailed in the Microsoft Excel workbook provided as section 4 of this application, in Tables 4-1 through 4-13.

20 3.1 Specific Rate Changes

In addition to the overall updating of rates to reflect the AESO's 2009 revenue requirement, the AESO provides the following comments on updates to some specific aspects of its rates.

25 3.1.1 Fort Nelson Demand Transmission Service Rate FTS

Rate FTS has been updated to continue to align with Rate DTS, consistent with the direction by the AUC on page 75 of Decision 2007-106 on the AESO's 2007 GTA. Specifically, Rate FTS includes:

- 30 • the same bulk system charge as Rate DTS;
- a local system charge that represents the greater of the actual cost of the ATCO Electric line providing service to Fort Nelson or the charges that would accrue to BC Hydro using the DTS local system charge; and
- 35 • the same operating reserve, voltage control, and other system support services charges as Rate DTS.

40 The AESO also notes that this rates update includes Interim Refundable Fort Nelson Rider H as currently approved in the AESO's tariff. Rider H is the subject of a separate extension application by the AESO (Application No. 1600831, Proceeding ID 150) currently before the AUC. This rates update application is not meant to supersede or otherwise impact that extension application. Any revisions to Rider H that are approved in the AUC's determination on the extension application will be incorporated into the AESO's tariff when that decision is released.

3.1.2 Opportunity Service Rates

The AESO's Demand Opportunity Service ("DOS") and Export Opportunity Service ("XOS") rates were the subject of several directions regarding their components and levels in Decision 2007-106. The AESO is not proposing any changes to the components which were used in determining the current DOS and XOS rates.

However, Direction 12 on page 74 of Decision 2007-106 suggested that the change in rate levels for opportunity rates should be consistent with the overall DTS rate change. The AESO has adopted this approach to update the DOS and XOS rates in this application.

First, the AESO's 2009 DTS revenue requirement as provided in this application was converted into \$/MWh amounts by dividing the cost attributed to each rate component by the forecast DTS energy billing determinant. The percentage increase or decrease to each rate component was then calculated, based on the comparable rate components approved in the AESO's 2007 GTA second refiling. Finally, the appropriate percentage changes were applied to the 2007 approved amounts for each component comprising the DOS and XOS rates, to provide rate changes consistent with the overall DTS rate change.

The calculations for the proposed DOS and XOS rate levels are summarized in Table 4-9 in section 4 of this application.

3.1.4 Primary Service Credit

In Decision 2007-106, the AUC directed on page 66 that the AESO implement a Primary Service Credit ("PSC") calculated as:

- 55% of the first three capacity tiers (up to 40 MW) of the DTS point of delivery ("POD") charge;
- 100% of the fourth capacity tier (incremental capacity above 40 MW) of the DTS POD charge; and
- 55% of the fixed (\$/month) component of the DTS POD charge.

As the DTS POD charge has been updated in this application, the AESO has accordingly updated the PSC as provided in Table 3-1 below. The PSC amounts determined in Table 3-1 are reflected in Rate PSC in section 5 of this application.

Table 3-1 Calculation of 2009 Primary Service Credit

Rate Component	DTS Charge Amount	Primary Service Credit	
		%	Amount
Billing Capacity Charge			
• First (7.5×SF) MW	\$3,955.00/MW	55%	\$2,175.00/MW
• Next (9.5×SF) MW	\$1,368.00/MW	55%	\$752.00/MW
• Next (23×SF) MW	\$802.00/MW	55%	\$441.00/MW
• All Remaining MW	\$425.00/MW	100%	\$425.00/MW
Customer Charge	\$7,030.00/month	55%	\$3,867.00/month

3.1.5 RGU Connection Costs in Rate STS

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

10 In Decision 2007-106 on the AESO’s 2007 GTA, the AUC commented on page 76, “The [AUC] has reviewed this calculation and considers the AESO RGUCC appears to be reasonable.” The AESO has therefore updated the RGUCC charge in Rate STS to the 2009 value of \$259.00/MW included in the attachment to Information Response BR.AESO-018 (a).

15 3.2 2009 Forecast Billing Determinants

20 The updated rate calculations are also based on the AESO’s forecast of rate billing determinants for 2009. Those billing determinants were in turn based on the 2009 load forecast in the AESO’s *Future Demand and Energy Outlook (2008-2028)*, which is the AESO’s long-term load forecast prepared in accordance with the AESO’s duties under the EUA and the *Transmission Regulation*.

25 The *Future Demand and Energy Outlook* includes a 20-year peak load and electricity consumption forecast for Alberta. The load forecast is generated from economic growth (GDP) information, oilsands production forecasts, and population projections by select customer sectors, with regional adjustments based on historical results and customer-driven growth expectations. The AESO’s *Future Demand and Energy Outlook (2008-2028)* is available on the AESO website at www.aeso.ca by following the path Transmission ► Planning ► Load Forecasting.

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

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

45 Substation fractions are applied to billing capacities to develop billing determinants for each of the POD charge capacity tiers. Substation fractions are also applied to develop the billing determinant for “equivalent” customers, used in the calculation of the fixed (\$/month) component of the DTS POD charge.

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

As has been the traditional practice in AESO rate calculations, the billing determinants used in the 2009 rates update calculations are provided in aggregate, in Table 4-10 of the rate calculations in section 4.

Additionally, Table 3-2 below provides a comparison of the forecast billing determinants in this rates update application to those used in the AESO's 2007 GTA. Demand and energy billing determinants have increased between 4% and 8% compared to the 2007 forecast. In particular, the directly metered billing determinants of coincident metered demand, highest metered demand, and metered energy have increased more-or-less uniformly by about 6%, 5%, and 4% respectively. The billing capacity determinant displays a somewhat larger increase at about 8%, which the AESO attributes to a more accurate assessment of the impacts of ratchets and contract capacities on billing capacity in the 2009 forecast.

The "equivalent" customers billing determinant is anomalous in that it remains about the same as the 2007 forecast. The AESO attributes this to a more accurate application of substation fractions in determining equivalent customers in the 2009 forecast. In particular, the previous forecast was developed in mid-2006, and only about six months of historical substation fraction data was available from which to develop capacity tier and equivalent

Table 3-2 2009 Forecast and 2007 Forecast Billing Determinants

DTS Billing Determinant	Unit	2009	2007	Increase (Decrease)	
		Forecast	Forecast	Amount	%
Coincident Metered Demand	MW-months	90,263.6	84,839.3	5,424.3	6.4%
Billing Capacity					
• Total Billing Capacity	MW-months	128,427.8	118,929.4	9,498.5	8.0 %
• First (7.5×SF) MW	MW-months	32,469.3	32,704.5	(235.2)	(0.7%)
• Next (9.5×SF) MW	MW-months	27,510.1	26,849.0	661.1	2.5%
• Next (23×SF) MW	MW-months	30,981.0	30,056.2	924.8	3.1%
• All Remaining MW	MW-months	37,467.4	29,319.7	8,147.8	27.8%
Highest Metered Demand	MW-months	106,663.4	101,353.4	5,310.0	5.2%
Metered Energy (All Hours)	GWh	56,988.1	54,682.5	2,305.6	4.2%
Customers (Equivalent)	customer-months	4,852.2	4,854.4	(2.2)	(0.0%)
Pool Price (Weighted by Volume)	\$/MWh	\$86.88	\$68.75	\$18.13	26.4%
Average Increase (Weighted by Revenue)					8.6%

customer billing determinants. The AESO considers that the 2009 forecast, based on three full years of historical substation fraction data, provides a more accurate determination of both the capacity tier and equivalent customer billing determinants.

5 To further examine the reasonableness of the 2009 forecast billing determinants, Table 3-3 below provides a comparison of the forecast billing determinants in this rates update application to the actual billing determinants recorded by the AESO in 2008 and 2007. The AESO considers that the increase in billing determinants forecast for 2009 is reasonable when compared to recorded billing determinants for the two prior years.

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Table 3-3 2009 Forecast, 2008 Recorded, and 2007 Recorded Billing Determinants

DTS Billing Determinants	Units	2009 Forecast	2008 Recorded	2007 Recorded
Coincident Metered Demand	MW-months	90,263.6	86,974.7	86,429.0
Billing Capacity (Total)	MW-months	128,427.8	124,991.8	120,774.4
Highest Metered Demand	MW-months	106,663.4	105,944.3	103,085.4
Metered Energy (All Hours)	GWh	56,988.1	54,202.3	53,783.3
Customers (Total)	customer-months	6,031	5,955	5,918

15 **3.3 Bill Impacts**

As noted in section 2 of this application, the AESO's 2009 forecast costs represent an increase of 26.9% over the total costs on which currently-approved rates were based in the AESO's 2007 GTA Second Refiling. However, billing determinants have also increased from the 2007 forecast on which currently-approved rates were based. As a result, the AESO's 2009 rates update represents an overall increase of 13.4% over the 2007 rates currently in place, including an increase of 19.3% to the AESO's Demand Transmission Service Rate DTS and a decrease of 3.1% to the AESO's Supply Transmission Service Rate STS.

25 As discussed in section 1.2 of this application, deferral accounts provide certainty that the AESO's costs will be exactly recovered by revenue, either through base rates or through deferral accounts. Increases in AESO costs will therefore flow to and impact customers through deferral accounts if rates are not increased. The changes in rates summarized above simply improve the timeliness and accompanying accuracy of the recovery of costs from customers.

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The increases to the different components of the DTS rate are provided in Table 3-4 on the next page. The DTS rate increase of 19.3% represents an average increase over all components of the DTS rate. Individual increases experienced by AESO customers will vary, depending on the specific characteristics of a customer's service including peak demand coincidence, billing capacity, load factor, and hourly pool price at the time of usage.

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Table 3-4 Increase (Decrease) to 2009 DTS Rate Components

DTS Rate Charge	Unit	Proposed (1 Jul 2009)	Current (1 Aug 2008)	Increase (Decrease)
Bulk System				
• Coincident Demand	\$/MW	\$2,229.00	\$1,946.00	14.5%
• Energy	\$/MWh	\$0.78	\$0.66	18.2%
Local System				
• Billing Capacity	\$/MW billing	\$653.00	\$577.00	13.2%
• Energy	\$/MWh	\$0.32	\$0.28	14.3%
Point of Delivery				
• First (7.5 × SF) MW BC	\$/MW	\$3,955.00	\$3,291.00	20.2%
• Next (9.5 × SF) MW BC	\$/MW	\$1,368.00	\$1,138.00	20.2%
• Next (23 × SF) MW BC	\$/MW	\$802.00	\$667.00	20.2%
• Remaining MW BC	\$/MW	\$425.00	\$353.00	20.4%
• Customer × SF	\$/month	\$7,030.00	\$5,849.00	20.2%
Operating Reserve	% of Pool Price	4.82%	3.33%	44.7%
Voltage Control	\$/MWh	\$0.65	\$0.93	(30.1%)
Other System Support	\$/MW	\$62.00	\$77.00	(19.5%)
Net Change				19.3%

5 To allow individual DTS customers to estimate the impact of the 2009 rates on their individual bills, the AESO has included a bill impact estimator as Table 4-14 in section 4 of this application. The bill impact estimator calculates bills for a given set of billing inputs under both the current 2007 rate and the proposed 2009 rate, to allow the impact of the rates update on an individual service to be estimated.

10 The decreases to the different components of the STS rate are provided in Table 3-5 below. The STS rate decrease of 3.1% represents an average decrease over all components of the STS rate. Individual decreases or increases experienced by AESO customers will vary, depending on the specific characteristics of a customer's service including whether it includes a previously-regulated generating unit subject to the regulated generating unit (RGU) connection costs charge.

Table 3-5 Increase (Decrease) to 2009 STS Rate Components

STS Rate Charge	Unit	Proposed (1 Jul 2009)	Current (1 Aug 2008)	Increase (Decrease)
Losses	% of Pool Price	4.66%	4.76%	(2.1%)
RGU Connection Costs	\$/MW	\$259.00	\$304.00	(14.8%)
Net Change				(3.1%)



In particular, the AESO notes that the loss factors provided in Table 3-5 are representative average loss factors only. The actual losses charge applicable to an individual customer will be based on a location specific loss factor determined in accordance with ISO Rule 9.2, as specified in the STS rate schedule.

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3.4 Future Rate Changes

Although the AESO is not seeking any direction or approval from the AUC for changes to rates beyond those explicitly included in this application, the AESO provides the following information for the interest of the AUC and stakeholders.

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The AESO recently began the consultation process for its 2010 GTA, which it expects to file in the third quarter of 2009. That application will include a review of the approach and methodology used to establish the AESO's rates, and is expected to propose a new structure for the DTS operating reserve charge, among other changes. The AESO further expects that the rates from its 2010 GTA will become effective about a year later, in the third quarter of 2010. The rates applied for in this 2009 rates update application could therefore be in effect from about July 2009 to the third quarter of 2010.

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The AESO considers that updating rates to reflect changes to revenue requirement is a practical approach to deal with the time required to consult on, prepare, and review a GTA. As well, a rates update that can be reviewed in a relatively quick process accommodates the approval of the AESO's budget just before (or in the current application, just after) the start of the budget year. For these reasons, the AESO anticipates filing rates update applications similar to this current application in the years between more comprehensive GTAs.

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As noted above, the AESO is not seeking any direction or approval from the AUC on this proposal. However, the AESO may offer additional comments and seek direction from the AUC on its approach to rates updates in its 2010 GTA.

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after the date of the AUC's decision, to allow adequate time to program and test the rates in the AESO's billing system.

Given the limited scope of the requested approvals, the AESO has not planned a technical meeting to review the application with stakeholders as part of the regulatory review process. However, if the AUC considers that such a meeting would aid the review process, the AESO will arrange a technical meeting on the application as promptly as possible.

Finally, also based on the limited scope of the requested approvals, the AESO suggests this application be reviewed through a written proceeding.

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Yours truly,

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