Title: Purpose of application

Reference: Application, page 3 of 22

Preamble: 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 tariff

Request:

(a) Why is the AESO filing for a change in rate levels now when on page 22 of the application the AESO has begun a consultation process and expects to file in the third quarter of 2009 an application which will review both rate levels and rate structure?

(b) Did the AESO engage in any form of consultation process with interested parties before proceeding with this application?

(c) Will this application reduce the need for any potential/future regulatory applications?

(d) Has the AESO initiated a consultation process with respect to rate design for its next rates application? If so, what is the status of that process? When would the AESO expect to file such an application? Has this plan changed from what was mentioned in the application?

Response:

(a) As discussed on page 5 of the application (lines 19-22), on current rates the AESO expects to recover only about 88% of its 2009 revenue requirement through base rate revenue. The remaining 12% would therefore need to be recovered through Riders C and E. The AESO considers that updating base rates rather than relying on deferral account riders provides a more accurate and timelier recovery of costs from customers. The AESO further considers the applied-for rates update to be straightforward and uncontroversial, and a reasonable approach to recovering costs.

As noted on page 22 of the rates update application, the AESO plans to file its 2010 general tariff application in the third quarter of 2009. The tariff resulting from that application is not expected to be approved and implemented until the third quarter of 2010 or later. That is at least 12 months after the July 1, 2009 effective date requested in the rates update application. Without the rates update, the AESO would continue to recover a large portion of its revenue requirement through deferral account riders for a year or more, which seems unnecessary when it can be remedied in large part by the rates update.

(b) The AESO included the 2009 rates update in general information provided with the preliminary list of potential matters to be addressed in its 2010 tariff application, distributed on February 5, 2009. The AESO also discussed the 2009 rates update in meetings with individual parties held as part of its 2010 tariff consultation. By the date of filing of the rates update application, the AESO had met individually with six parties in its 2010 tariff consultation and had raised the 2009 rates update in those meetings.

The AESO also included discussion of the rates update application in a consultation meeting on March 3, 2009, on the AESO's 2008 deferral account reconciliation application and related deferral account matters.

The AESO did not hold a specific consultation process on the 2009 rates update application itself, as the AESO considered the rates update to be straightforward and uncontroversial.

(c) The AESO does not expect this application to reduce the need for any potential or future regulatory applications. As explained on page 4 of the application (lines 42-44), "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." It is expected that the rates update will significantly reduce the amounts that will need to be reconciled and reallocated to customers in future deferral account reconciliation applications, as further discussed in information response AUC.AESO-002.

(d) The AESO began consultation on its 2010 tariff application on February 5, 2009, by distributing a preliminary list of potential matters to be addressed as discussed in part (b) above. The AESO has since:

- met individually with parties to discuss the preliminary list,
- updated the list based on further review of the tariff by the AESO and on comments received from parties,
- held a general stakeholder meeting to discuss preliminary proposals for the 2010 application,
- formed several small working groups which have met one or more times to explore specific topics for the 2010 application, and
- held a second general stakeholder meeting to provide an update on the working group discussions and 2010 application development.

The AESO expects to complete most of the working group discussions in July 2009, to hold a final general stakeholder meeting on the application in early September 2009, and to file the application in late September 2009. This plan is essentially the same as mentioned in the application, although the AESO had not anticipated the number of working groups that would be formed and had initially intended to file the application earlier in the third quarter of 2009.

Reference: Application, page 4 of 22

Preamble: 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.

Request:

(a) How does this application fix the imprecise recovery or refund of shortfalls through deferral account Rider C?

(b) Will this application remove the need for future Rider C applications?

(c) Please quantify the imprecise recovery or refund of shortfalls or surpluses through deferral account Rider C.

(d) Has the AESO received any concerns from its customers with respect to the operation of Rider C? If so please disclose those concerns.

Response:

(a) The imprecise recovery or refund of amounts through Rider C results from two aspects of the rider.

First, Rider C recovers or refunds amounts through a simple $/MWh fixed energy charge or credit for each of the main components of the AESO’s Demand Transmission Service (DTS) rate: interconnection, operating reserve, voltage control, and other ancillary services. However, some of the charges in those four components of the DTS rate are based on billing determinants other than MWh. Specifically:

- the interconnection charge is primarily a $/MW demand charge,
- the operating reserve charge is a percentage of pool price varying energy charge, and
- the other ancillary services charge is a $/MW demand charge.

Since the basis for Rider C is different from the bases for these DTS rate component charges, addressing shortfalls or surpluses through Rider C would likely result in different charges to customers compared to recovery of the AESO’s revenue requirement solely through base rates. (The AESO notes that the voltage control charge is a $/MWh charge, which would likely result in similar charges whether voltage control costs were recovered through Rider C or through base rates.)

Second, Rider C recovers or refunds shortfalls or surpluses in the quarter following that in which the shortfall or surplus accrued, and the quarterly recovery is subsequently reconciled after year-end. Rider C therefore creates timing differences compared to recovery of the AESO's revenue requirement solely through base rates, and those timing difference may exist for over a year until a deferral account reconciliation is approved for settlement with customers.

By allowing the recovery of a greater portion of the AESO's revenue requirement through base rates and reducing the portion recovered through Rider C, the rates update will reduce the impact of both of these aspects of Rider C.

(b) This application will not remove the need for future deferral account reconciliation applications, but should reduce the deferral account balances (prior to Rider C collections or refunds) addressed in those applications.

(c) It is difficult to quantify the impact as it is affected by AUC approvals of TFO tariffs and other applications, customer volumes, pool price, and other factors. The AESO further notes that over 80% of its DTS revenue requirement is charged to distribution facility owners, who recover those charges from their customers connected to distribution systems at 25 kV or lower voltage. The AESO has no visibility of the impact, if any, of the imprecision of Rider C charges or credits on those customers.

The clearest indication of the imprecision of Rider C would be:

- charges to a customer through Rider C which are subsequently refunded to that customer in a deferral account reconciliation, and
- refunds to a customer through Rider C which are subsequently collected from that customer in a reconciliation.

Table 11-1 in the AESO's 2008 deferral account reconciliation application provides some quantification of such impacts. The 2008 application reconciled a net deferral account shortfall of $6.4 million, and included customer refunds totaling $0.6 million and customer charges totaling $7.0 million. This indicates that at least $0.6 million (or 10%) of the $6.4 million net shortfall was imprecisely recovered through Rider C, and had to be subsequently refunded to customers as a result of the reconciliation after year-end.

Table 11-1 provides a quantification only of the annual impact. Amounts may also be charged through Rider C in one quarter and refunded in a subsequent quarter, or refunded in one quarter and collected in a subsequent quarter. Such quarterly exchanges would not be visible in Table 11-1. As well, for distribution facility owners similar impacts probably occur at individual points of delivery which would not be visible at the aggregate customer level in Table 11-1.

Section 11 (pages 98-99) of the AESO's 2008 deferral account reconciliation application (Application 1604964 and Proceeding ID 186, filed on April 9, 2009) is attached and provided Table 11-1 for ease of reference.

(d) The AESO has heard concerns from customers about the magnitude and variability of Rider C charges, but not about the operation of Rider C itself. The AESO understands customers are generally supportive of the quarterly Rider C methodology as long as the amounts recovered or refunded are relatively small. However, customers express concerns when Rider C amounts become large or difficult to predict.

11 PROPOSED METHOD OF REFUNDING AND COLLECTING

421 Consistent with the approach approved for the AESO's 2003 and 2004-2007 deferral account reconciliations, the AESO proposes to settle the outstanding deferral account balances through a one-time payment and collection option.

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

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

11.1 Immediate Interim Settlement

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

425 The AESO considers that the reasons set out in section 1.2 provide a sufficient basis to allow the AUC to conclude that interim settlement of the deferral account balances in the amounts allocated in this application would be both accurate and in the public interest. The AESO will therefore plan interim settlement on invoices to be issued in June 2009, pending approval of the AUC.

426 Appendix H includes the total DTS and STS amounts that will be settled with individual customers on an interim refundable basis as a result of this application, pending approval of the AUC. Table 11-1 summarizes the distribution of charges and refunds among individual DTS and individual STS customers.

427 Table 11-1 indicates that 11 DTS and 11 STS customers will receive refunds totalling $0.6 million while 39 DTS and 30 STS customers will receive charges totalling $7.0 million, as a result of this 2008 application.

428 The total charges are $0.6 million more than the $6.4 million net deferral account shortfall being settled. This $0.6 million amount indicates the magnitude of the reallocation of Rider C charges and refunds among customers in this reconciliation. The AESO submits that settlement of the amounts in this application would therefore improve the accuracy of the

Table 11-1 Distribution of Charges and Refunds Among Customers

Range of Refunds and Charges	Number of Customers DTS	Number of Customers STS	Total Amount, $ 000 000 DTS	Total Amount, $ 000 000 STS	Total Amount, $ 000 000 Total
Refund Greater Than $100,000	1	-	$0.3	-	$0.3
Refund of $0 to $100,000	10	11	0.3	0.1	0.3
Subtotal Refunds	11	11	$0.6	$0.1	$0.6
Charge Greater Than $0 to $100,000	28	23	(0.6)	(0.4)	(1.1)
Charge Greater Than $100,000 to $500,000	9	6	(1.9)	(1.8)	(3.7)
Charge Greater Than $500,000 to $1,000,000	1	1	(0.6)	(0.6)	(1.2)
Charge Greater Than $1,000,000	1	-	(1.1)	-	(1.1)
Subtotal Charges	39	30	($4.2)	($2.8)	($7.0)
Total Refunds and Charges	50	41	($3.6)	($2.8)	($6.4)

Note: Numbers may not add due to rounding.

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

429 As already noted, the amounts settled on invoices issued in June 2009 would be interim and refundable, and subject to adjustment in the final decision on the 2008 deferral account reconciliation application following a full regulatory review. In the event such adjustment is required, the AESO proposes that the impact of the adjustment be assessed to determine whether a separate settlement process is required or whether the adjustment can be included in the 2009 deferral account reconciliation application expected to be filed in the second quarter of 2010.

430 The AESO suggests it may be efficient to continue to settle future deferral account reconciliations on an immediate interim basis upon filing, with any required minor adjustments included in the following year's deferral account reconciliation. However, in this application the AESO is not seeking any direction with respect to settlement of future deferral account reconciliations.

Reference: Application, page 4 of 22

Preamble: 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 customers.

Request:

How does this application address the above noted concerns with respect to the deferral account reconciliation application?

Response:

As discussed in Information Response AUC.AESO-002 (a), Rider C recovers or refunds shortfalls or surpluses in the quarter following that in which the shortfall or surplus accrued, and the quarterly recovery is subsequently reconciled after year-end.

The applied-for rates update would recover a greater portion of the AESO's revenue requirement through base rates, and correspondingly reduce the portion recovered through Rider C. Accordingly, a smaller portion of the AESO's revenue requirement would be subject to Rider C recovery in the quarter following that in which a shortfall accrued, and a smaller portion would also be subject to subsequent reconciliation after year-end. This would reduce the amount of costs which would be subject to the timing delays mentioned in the referenced paragraph of the application.

AUC.AESO-004

Reference: Application, page 5 of 22

Preamble: 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 actual costs.

Request:

Please provide support for the 31% identified in the above statement.

Response:

The 31% is the rounded largest value provided in Table 1-1 on page 5 of the application.

Table 1-1 summarizes, by rate component, the 2008 revenue from base rates and riders, and includes in the 5th column of numbers the collections or refunds through Riders C and E as a percentage of the cost of each rate component. Those percentages range from a 29.0% refund of other system support costs through Rider C to a 31.5% collection of operating reserve costs through Rider C. An additional decimal place in Table 1-1 would provide the relevant operating reserve value as 31.46%, which was rounded to 31% in the referenced paragraph from the application.

Title: Administrative costs

Reference: Application, page 15 of 22

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

Request:

Please describe how Administrative costs are allocated between the three AESO functions.

Response:

The following cost allocation methodology is used to allocate direct and corporate service costs to the three AESO business functions.

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

(b) For **corporate service departments**, the cost allocation is based on the costs associated with the direct operating departments. This methodology assumes that the business function with higher costs would contribute to a higher demand for corporate services and therefore be assigned a higher percentage allocation.

(c) For **corporate IT costs**, the allocation is based on 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.

(d) For **rent costs**, the allocation is based on the number of staff associated with the three business functions.

(e) **Interest costs** are allocated to the business functions based on the financial transactions that give rise to the utilization of the credit facilities. The allocation of interest to a business function is determined by the proportion of that business function's monthly deferral balances and the net book value of capital assets to the corporate totals.

(f) **Amortization costs** related to capital purchases for the support of a specific business function are directly assigned to that function. Amortization costs related to capital that cannot be specifically identified as supporting one function are allocated to the business functions based on management judgment, taking into consideration the business and operating activities that will be supported on the systems.

The AESO last presented the full allocation methodology to the AESO Board as part of the budget approval process for 2008 and 2009. The detailed allocation methodology was contained in the AESO Board Decision Document dated November 23, 2007, and the relevant sections of that document are provided as Attachment AUC.AESO-005. The full document is available on the AESO website at www.aeso.ca by following the path About AESO ▶ Our Business ▶ Business Plan and Budget ▶ 2008 & 2009 Business Priorities and Budget, via the link titled, “2007-11-23 - Final Board Decision Document”.

the EMS is scheduled to begin in 2007 with completion targeted for 2009. This replacement is a significant enhancement to the hardware and software of the business system used by the system controllers to supervise and direct the operations of the power system. The AESO Board approved funding of $14.4 million in October 2007 for the implementation phase of the project, with total project funding approved to date of $15.6 million.

20.3 Calgary Place Office Space Expansion

In order to accommodate staff growth, the AESO acquired 5,000 square feet of additional office space in 2007 which is adjacent to existing office space occupied by the AESO. In mid-2007, the AESO Board approved a capital budget of $0.8 million (in addition to the $0.3 million included in the 2007 general capital budget) for office space renovations after a review of the office space utilization concluded that in addition to acquiring additional space, the existing space could be more effectively utilized to address additional growth requirements.

21.0 COST ALLOCATION METHODOLOGY

21.1 Overview

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 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.

The following table and descriptions highlight the allocation percentages used for 2007 through 2009 based on the business activities in the various departments.

TABLE 1 - 2007-2009 Cost Allocation Percentages

AESO Department	Transmission	Energy Market	Load Settlement
DIRECT OPERATING			
500kV System Planning	100%	0%	0%
Regional Planning	100%	0%	0%
Resource Adequacy	50%	50%	0%
Engineering	100%	0%	0%
Customer Services	100%	0%	0%
Technical Services	100%	0%	0%
System Operations	67%	33%	0%
Operations Planning	75%	25%	0%
Commercial	100%	0%	0%
Regulatory	100%	0%	0%
Market Dev & Ops	0%	100%	0%
Load Settlement	0%	0%	100%
SHARED SERVICES			
Corporate Infrastructure[1]	Based on Direct Operating Group Costs		
Information Technology[2]	65%	28%	7%
Office Lease	Based on AESO Staff Count		
CAPITAL			
SCC Building[3]	67%	33%	0%
IT Capital	Assigned on a project basis		

[1] Includes the following departments: Executive Office, AESO Board, Accounting, Settlement & Risk, Information Technology, Customer Services, Human Resources, Stakeholder Relations/ Communications
[2] Based on 2006 actual allocations
[3] Based on the utilization and allocation percentages of the departments occupying the building

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

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.

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

For corporate service departments, the cost allocation is based upon the costs associated with the direct operating groups (discussed in 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.

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.

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.

The allocation of the AESO's <u>capital expenditures</u> (primarily IT expenditures) is based upon the following principles:

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

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).

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

The cost allocation methodology as discussed has not changed from that used in prior years though the allocation percentages change to reflect the business/operational activities each year. Appendix K provides the detailed calculation of the cost allocation for 2008 to 2009 based on the G&A budgets and staff count.

21.2 Update of Assumptions for 2008 to 2009

It is anticipated that the allocation percentages will not materially change in 2008 and 2009 in comparison to 2007.

21.3 2008 to 2009 Cost Recovery Allocations

The following table provides a summary presentation of the AESO's G&A budgets by funding area based upon the allocation percentages previously discussed.

TABLE 2 – Budget G&A Allocations
(including interest and amortization and excluding interconnection application fees for transmission)

Funding	Recovery Basis
Transmission Tariff	Charge to transmission customers in accordance with tariff rate design
Energy Market Trading Charge	Charge to energy market participants based upon MWh exchanged through the power pool
Load Settlement Charge	Charge to Load Settlement Agents based upon service area MWh

Funding	2009 Budget	2008 Budget	2007 Budget	2006 Actual	2006 Budget	2005 Actual
Transmission Tariff	$55.0M	$51.8M	$41.4M	$32.0M	$32.2M	$31.1M
Energy Market Trading Charge	$18.3M	$16.5M	$15.7M	$13.3M	$15.3M	$13.0M
Load Settlement Charge	$6.5M	$6.4M	$6.2M	$4.8M	$5.6M	$2.7M
Total G&A	$79.8M	$74.7M	$63.3M	$50.1M	$53.1M	$46.8M

= Inputs   = YE Inputs

AESO Cost Allocation
($ millions)

2008

Line		Allo-cation Notes	Transmission: Est. % split to Trans (a)	Transmission: Staff Count Equiv* (b)	Transmission: Actual Amount ($) (c)	Energy Market: Est. % split to Ener Mkt (a)	Energy Market: Staff Count Equiv* (b)	Energy Market: Actual Amount ($) (c)	Load Settlement: Est. % split to Load Set (d)	Load Settlement: Staff Count Equiv* (e)	Load Settlement: Actual Amount ($) (f)	AESO Total: Total % (g)	AESO Total: Head Count Equiv* (h)	AESO Total: Total Actual Amount ($) (i)
1	**DIRECT OPERATING GROUPS**													
	OPERATIONS & RELIABILITY													
2	System Operations	1	67%	26.8	4.1	33%	13.2	2.0	0%	0.0	0.0	100%	40.0	6.2
3	Operations Planning	1	75%	19.5	3.4	25%	6.5	1.1	0%	0.0	0.0	100%	26.0	4.5
4	Subtotal Operations & Reliability			46.3	7.5		19.7	3.2		0.0	0.0		66.0	10.7
	TRANSMISSION													
5	Engineering	1	100%	15.0	3.2	0%	0.0	0.0	0%	0.0	0.0	100%	15.0	3.2
6	Technical Services	1	100%	7.0	1.0	0%	0.0	0.0	0%	0.0	0.0	100%	7.0	1.0
7	500kV System Planning	1	100%	8.0	2.2	0%	0.0	0.0	0%	0.0	0.0	100%	8.0	2.2
8	Regional Planning	1	100%	16.0	3.1	0%	0.0	0.0	0%	0.0	0.0	100%	16.0	3.1
9	Customer Services	1	100%	4.0	0.6	0%	0.0	0.0	0%	0.0	0.0	100%	4.0	0.6
10	Resource Adequacy	1	50%	2.0	0.4	50%	2.0	0.4	0%	0.0	0.0	100%	4.0	0.9
11	Subtotal Transmission			52.0	10.6		2.0	0.4		0.0	0.0		54.0	11.0
	MARKET SERVICES													
12	Market Services	1	0%	0.0	0.0	100%	9.0	1.7	0%	0.0	0.0	100%	9.0	1.7
13	Commercial	1	100%	3.0	0.7	0%	0.0	0.0	0%	0.0	0.0	100%	3.0	0.7
14	Regulatory	1	100%	10.0	2.0	0%	0.0	0.0	0%	0.0	0.0	100%	10.0	2.0
15	Subtotal Market Services			13.0	2.7		9.0	1.7		0.0	0.0		22.0	4.4
16	COMPLIANCE	1	0%	0.0	0.0	0%	0.0	0.0	100%	11.0	1.7	100%	11.0	1.7
17	**Total Direct Operating Group Costs**			**111.3**	**20.8**		**30.7**	**5.3**		**11.0**	**1.7**		**153.0**	**27.7**
18	% of Total Direct Staff Count and Oper Costs			72.7%	74.9%		20.1%	19.1%		7.2%	6.0%		100.0%	100.0%
19	**CORPORATE SERVICE COSTS**													
20	INFORMATION TECHNOLOGY	1	65%	37.7	8.6	28%	16.2	3.7	7%	4.1	0.9	100%	58.00	13.2
21	CORPORATE INFRASTRUCTURE	2	75%	47.2	13.4	19%	12.0	3.4	6%	3.8	1.1	100%	63.00	17.9
22	OFFICE LEASE	3	72%	n/a	1.5	22%	n/a	0.5	7%	n/a	0.1	100%	n/a	2.1
23	**Total Corporate Service Costs**			**84.9**	**23.5**		**28.3**	**7.6**		**7.8**	**2.1**		**121.00**	**33.3**
24	% of Total Corp Services Staff Count and Oper Costs			70.2%	70.8%		23.3%	22.8%		6.5%	6.5%		100.00%	100.00%
25	**Total Transmission (L16 + L22)**			**196.2**	**44.3**									
26	% of Total AESO Staff Count and Oper Costs			71.6%	72.7%									
27	**Total Energy Market (L16 + L22)**						**59.0**	**12.9**						
28	% of Total AESO Staff Count and Oper Costs						21.5%	21.1%						
29	**Total Load Settlement (L16 + L22)**									**18.8**	**3.8**			
30	% of Total AESO Staff Count and Oper Costs									6.9%	6.3%			
31	**Total AESO Operating Budget (L16 + L22)**												**274.0**	**61.0**
32	% 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

= Inputs   = YE Inputs

AESO Cost Allocation
($ millions)

2009

Line		Allo-cation Notes	Transmission: Est. % split to Trans (a)	Transmission: Staff Count Equiv* (b)	Transmission: Actual Amount ($) (c)	Energy Market: Est. % split to Ener Mkt (a)	Energy Market: Staff Count Equiv* (b)	Energy Market: Actual Amount ($) (c)	Load Settlement: Est. % split to Load Set (d)	Load Settlement: Staff Count Equiv* (e)	Load Settlement: Actual Amount ($) (f)	AESO Total: Total % (g)	AESO Total: Head Count Equiv* (h)	AESO Total: Total Actual Amount ($) (i)
1	**DIRECT OPERATING GROUPS**													
	OPERATIONS & RELIABILITY													
2	System Operations	1	67%	28.8	4.7	33%	14.2	2.3	0%	0.0	0.0	100%	43.0	7.0
3	Operations Planning	1	75%	20.3	3.7	25%	6.8	1.2	0%	0.0	0.0	100%	27.0	5.0
4	Subtotal Operations & Reliability			49.1	8.4		20.9	3.5		0.0	0.0		70.0	11.9
	TRANSMISSION													
5	Engineering	1	100%	15.0	3.2	0%	0.0	0.0	0%	0.0	0.0	100%	15.0	3.2
6	Technical Services	1	100%	7.0	1.1	0%	0.0	0.0	0%	0.0	0.0	100%	7.0	1.1
7	500kV System Planning	1	100%	8.0	1.8	0%	0.0	0.0	0%	0.0	0.0	100%	8.0	1.8
8	Regional Planning	1	100%	16.0	3.2	0%	0.0	0.0	0%	0.0	0.0	100%	16.0	3.2
9	Customer Services	1	100%	4.0	0.7	0%	0.0	0.0	0%	0.0	0.0	100%	4.0	0.7
10	Resource Adequacy	1	50%	2.0	0.4	50%	2.0	0.4	0%	0.0	0.0	100%	4.0	0.8
11	Subtotal Transmission			52.0	10.4		2.0	0.4		0.0	0.0		54.0	10.8
	MARKET SERVICES													
12	Market Services	1	0%	0.0	0.0	100%	9.0	1.8	0%	0.0	0.0	100%	9.0	1.8
13	Commercial	1	100%	3.0	0.7	0%	0.0	0.0	0%	0.0	0.0	100%	3.0	0.7
14	Regulatory	1	100%	10.0	2.0	0%	0.0	0.0	0%	0.0	0.0	100%	10.0	2.0
15	Subtotal Market Services			13.0	2.6		9.0	1.8		0.0	0.0		22.0	4.4
16	COMPLIANCE	1	0%	0.0	0.0	0%	0.0	0.0	100%	11.0	1.7	100%	11.0	1.7
17	**Total Direct Operating Group Costs**			**114.1**	**21.4**		**31.9**	**5.7**		**11.0**	**1.7**		**157.0**	**28.9**
18	% of Total Direct Staff Count and Oper Costs			72.6%	74.2%		20.3%	19.9%		7.0%	5.9%		100.0%	100.0%
19	**CORPORATE SERVICE COSTS**													
20	INFORMATION TECHNOLOGY	1	65%	41.6	9.4	28%	17.9	4.1	7%	4.5	1.0	100%	64.00	14.5
21	CORPORATE INFRASTRUCTURE	2	74%	49.0	13.6	20%	13.1	3.6	6%	3.9	1.1	100%	66.00	18.3
22	OFFICE LEASE	3	71%	n/a	1.5	22%	n/a	0.5	7%	n/a	0.1	100%	n/a	2.2
23	**Total Corporate Service Costs**			**90.6**	**24.5**		**31.0**	**8.2**		**8.4**	**2.2**		**130.00**	**35.0**
24	% of Total Corp Services Staff Count and Oper Costs			69.7%	70.2%		23.9%	23.4%		6.5%	6.4%		100.00%	100.00%
25	**Total Transmission (L16 + L22)**			**204.6**	**46.0**									
26	% of Total AESO Staff Count and Oper Costs			71.3%	72.0%									
27	**Total Energy Market (L16 + L22)**						**63.0**	**13.9**						
28	% of Total AESO Staff Count and Oper Costs						21.9%	21.8%						
29	**Total Load Settlement (L16 + L22)**									**19.4**	**4.0**			
30	% of Total AESO Staff Count and Oper Costs									6.8%	6.2%			
31	**Total AESO Operating Budget (L16 + L22)**												**287.0**	**63.9**
32	% 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

Cost Allocation by Cost Category

	2008				2009			
($ millions)	Trans-mission	Energy Market	Load Settlement	Total	Trans-mission	Energy Market	Load Settlement	Total
Administrative Costs								
Staff Costs	20.8	6.1	2.0	28.8	23.2	7.0	2.2	32.4
Benefit Costs	4.6	1.4	0.4	6.4	5.2	1.6	0.5	7.2
Incentive Costs	2.8	0.8	0.3	3.8	3.1	0.9	0.3	4.3
Total Staff and Benefits	28.2	8.3	2.7	39.1	31.5	9.5	3.0	43.9
Consultants	5.8	1.4	0.4	7.5	4.2	1.2	0.2	5.6
IT Telecomm & Maintenance Costs	2.3	1.0	0.2	3.5	2.5	1.1	0.3	3.8
Rent	2.0	0.7	0.1	2.8	2.1	0.7	0.1	2.9
Other Admin Costs	2.4	0.7	0.2	3.2	2.2	0.7	0.2	3.0
Travel and Training	1.7	0.4	0.1	2.2	1.5	0.4	0.1	2.0
Audits/Reviews	0.6	0.1	0.0	0.7	0.7	0.1	0.0	0.8
AESO Board Member Fees	0.5	0.1	0.0	0.7	0.5	0.1	0.0	0.7
Insurance	0.4	0.1	0.0	0.6	0.4	0.1	0.0	0.6
External Legal Costs	0.5	0.0	0.0	0.6	0.4	0.0	0.0	0.5
TOTAL ADMINISTRATIVE	44.3	12.9	3.8	61.0	46.0	13.9	4.0	63.9
Interest	1.7	0.9	0.3	2.9	1.8	0.9	0.2	2.9
Amortization & Depreciation	5.8	2.7	2.3	10.8	7.3	3.4	2.3	13.0

Title: Forecast Billing Determinants

Reference: Application, page 18

Preamble: 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.

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.

Request:

(a) How does the preparation of this forecast information differ from the forecasting methodology employed by the AESO when it files a full GTA before the AUC?

(b) Please provide a copy of the document "Future Demand and Energy Outlook (2008-2028)" (hereinafter "FDEO Report").

(c) In consideration of the statement on page 18 that updated 2009 billing determinates were based on the 2009 load forecast in the FDEO Report, please provide detailed explanations of how each the following 2009 billing determinant forecasts used in the 2009 update application were developed from information provided in the FDEO:

(i) Coincident Metered Demand (90,263.6 MW-months)

(ii) Total Billing Capacity (128,427.8 MW-months)

(iii) Highest Metered Demand (106,663.4 MW-months)

(iv) Metered Energy (All Hours) (56,988.1 GWh)

Response:

(a) The billing determinants forecast methodology employed by the AESO for the rates update is the same as the methodology employed for a full GTA filing.

(b) Please see Attachment AUC.AESO-006 (b), which is the *Future Demand and Energy Outlook (2008-2028)* posted on the AESO website on January 30, 2009.

(c) The methodology employed by the AESO creates forecast hourly loads in MW for every load metering point, as shown in Figure 3.1-1 on page 8 of the *Future Demand and Energy Outlook (2008 – 2028)*. By using hourly information the AESO can calculate all forecasted DTS billing determinants.

(i) For coincident metered demand, the monthly hour of the peak coincidence of all DTS points is first determined. The load in MW for all DTS points in each of those twelve monthly hours is then summed to arrive at 90,263.6 MW-months.

(ii) For total billing capacity, the following values are first determined:

- the forecast maximum hourly load in MW for each DTS point in each month based on the forecast hourly load,
- The forecast contract capacity for each DTS point based on current contract capacity and known contract value changes in each month, and
- the highest metered demand for each DTS point in each 24-month period ending with each month in the forecast year.

The billing capacity for each DTS point is then calculated based on the definition provided in the DTS rate, and summed over all DTS points and over all 12 months to arrive at 128,427.8 MW-months.

(iii) For highest metered demand, the forecast maximum hourly load in MW for each DTS point in each month is determined and then summed over all DTS points and over all 12 months to arrive at 106,663.4 MW-months.

(iv) For metered energy, the forecast hourly load in MW is summed over all DTS points and over all 12 months to arrive at 56,988.1 GWh.

Title: Forecast Billing Determinants – 2009 Metered Energy Forecast

Reference: Application Section 3.2, pages 18-20

Preamble: Table 3-3 describes the 2007 and 2008 amounts for metered energy (53,783.3 GWh and 54,202.3 GWh respectively) as well as the 2009 forecast (56,988.1 GWh). Whereas the 2007 to 2008 increase in metered energy consumption was 0.78%, the AESO forecast indicates that 2009 metered energy will increase by 5.13% over the 2008 recorded amount.

Request:

(a) In consideration of the comparatively flat increase in metered energy consumption between 2007 and 2008 and the potential impacts of global economic events on Alberta energy consumption, please provide the AESO's rationale for forecasting that 2009 metered energy consumption will rise by more than 5% over recorded 2008 metered energy consumption.

(b) Whereas Section 1.0 of the FDEO Report indicates that it was completed in the third quarter of 2008, Section 1.1 of the FDEO Report entitled "Economic Update November 2008" provides an assessment of the impact of global economic events on the future demand for electricity in Alberta. Please describe what adjustments, if any, were made to the AESO's 2009 metered energy forecast to reflect the November 2008 economic update described in Section 1.1 of the FDEO Report.

Response:

(a) The AESO's process to annually update its long term energy and demand forecast is outlined in the *Future Demand and Energy Outlook (2008-2028)*. This work was completed in the third quarter of 2008 before the major economic events in 2008. In particular, the 2009 metered energy forecast was completed before the 2008 calendar year had passed, and was based on economic information from Spring 2008.

The AESO has established a regular and thorough process for developing its long term forecast. In general, it is impractical to repeatedly revisit a forecast as economic events unfold, especially when the events are subject to considerable uncertainty. The AESO further notes that, with respect to billing determinants, it is more conservative to **not** reduce the forecast as lower billing determinants would result in higher charges in the AESO's rates.

(b) No adjustments were made to the AESO's 2009 energy forecast to reflect the November 2008 economic update.

Title: RGU Connection Costs in Rate STS

Reference: Application Section 3.1.5, page 18

Preamble: 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.

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).

Request:

Please provide a copy of the attachment to the AESO’s response to BR.AESO-018(a) from the AESO’s 2007 GTA proceeding.

Response:

Please see Attachment AUC.AESO-008, which provides Schedule BR.AESO-018 (a) filed on January 24, 2007 in the AESO’s 2007 GTA proceeding.

AESO Response to Information Request
Calculation of Regulated Generating Unit Connection Cost Charge

Year	RGU Connection Costs $ 000 000	Annual Decline 4%/year $ 000 000	RGUCC Mid-Year Amount $ 000 000	RGUCC Original MCRs MW-months	RGUCC Charge $/MW-month
1996	43.9	1.8	43.0	88,240.8	$487.11
1997	42.1	1.8	41.2	88,240.8	467.23
1998	40.4	1.8	39.5	88,240.8	447.34
1999	38.6	1.8	37.7	88,240.8	427.46
2000	36.8	1.8	36.0	88,240.8	407.58
2001	35.1	1.8	34.2	88,240.8	387.70
2002	33.3	1.8	32.5	88,240.8	367.82
2003	31.6	1.8	30.7	88,240.8	347.93
2004	29.8	1.8	28.9	79,202.4	365.49
2005	28.1	1.8	27.2	79,202.4	343.34
2006	26.3	1.8	25.4	77,941.2	326.38
2007	24.6	1.8	23.7	77,941.2	303.88
2008	22.8	1.8	21.9	77,941.2	281.37
2009	21.1	1.8	20.2	77,941.2	258.86
2010	19.3	1.8	18.4	77,941.2	236.35
2011	17.5	1.8	16.7	70,395.6	236.76
2012	15.8	1.8	14.9	70,395.6	211.84
2013	14.0	1.8	13.2	68,664.0	191.63
2014	12.3	1.8	11.4	64,948.8	175.58
2015	10.5	1.8	9.6	64,948.8	148.57
2016	8.8	1.8	7.9	64,948.8	121.55
2017	7.0	1.8	6.1	64,948.8	94.54
2018	5.3	1.8	4.4	58,262.4	75.28
2019	3.5	1.8	2.6	58,262.4	45.17
2020	1.8	1.8	0.9	58,262.4	15.06

Notes:
Decision U97065 deemed RGU connection costs to be $43.9 million on January 1, 1996 (p. 652).
Decision 2000-1 determined that an appropriate amortization period should be 25 years, and that RGU connection costs should decline at a rate of 4% per year (p. 119).